Docket:	:	A.15-09-007
Exhibit Number	:	
Reference Number	:	ORA-02
Commissioner	:	C. Peterman
ALJ	:	K. MacDonald
Witness	:	N. Stannik

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Prepared Testimony Application of PacifiCorp for Authority to Sell Certain Mining Assets in Accordance with Public Utilities Code Section 851

ORA Supporting Attachments

San Francisco, California
July 11, 2016

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8	79	ORA-03	01	
9	81, 85	ORA-01	05	Attach ORA 1.5.xlsx

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ORA Data Request 1.2

For the purposes of this data request, "the Transaction" should be understood to include all of the transactions related to or required to facilitate the transfer of PacifiCorp's Mining Assets to Bowie Resource Partners, LLC (Bowie) as proposed in A.15-09-007, including, without limitation, the transaction required to transfer ownership in the Fossil Rock Mine.

Please provide all written communications in calendar years 2015 and 2016 between PacifiCorp or its affiliates and Bowie or its affiliates regarding the Transaction, along with an index of the communications.

Response to ORA Data Request 1.2

PacifiCorp objects to this request as overly broad, unduly burdensome, not reasonably calculated to lead to the discovery of admissible evidence; and as requesting information protected by the attorney-client privilege, attorney work product doctrine, or confidentiality agreement. Without waiving these objections, the Company responds as follows:

Internal emails are not routinely saved but are automatically deleted in the normal course of business after 100 days unless deliberately saved by a user. PacifiCorp conducted an internal review of emails maintained by the individuals involved in the Transaction during the requested timeframe. Please refer to Confidential Attachment ORA 1.2, which contains all available emails between the Company or its affiliates and Bowie, relating to the Transaction for the requested period.

Emails in the attachment have been categorized into folders by sender/receiver. Emails that include Highly Confidential information require special handling. Please contact Cathie Allen (813) 503-5934 to arrange to review those emails.

Confidential information is provided subject to California Public Utilities Code Section 583 and General Order 66-C.

From:	Hall, Richard
To:	Kim Colton (KColton@vancott.com)
Cc:	Brian Settles (BSettles@bowieresources.com)
Subject:	PacifiCorp/Bowie - Bills of Sale
Date:	Tuesday, June 02, 2015 7:37:00 AM
Attachments:	79132793_1.DOC.doc 79132793_1.DOC.doc 79135480_1.DOC.DOC 79136237_1.DOC.DOC

Kim,

Attached are the following bills of sale for the PacifiCorp/Bowie transaction:

1. Prep Plant Bill of Sale (personal property)
2. Prep Plant culinary lines Bill of Sale
3. Central Warehouse Bill of Sale

I have left the redlines on in both the Central Warehouse bill of sale and the Prep Plant culinary line bill of sale, identifying the changes between those documents and the Prep Plant bill of sale (personal property), which I used as the base form.

There is no personal property listed at Trail Mountain, so I have not prepared a BoS. Obviously, no personal property at Fossil Rock.

Let me know what comments or questions you have on these documents. Thanks.

Rich

Richard R. Hall | **Partner**
STOEL RIVES LLP |201 S. Main St., Suite 1100 | Salt Lake City, UT 84111
Direct: (801) 578-6960 | Fax: (801) 578-6999

101 S. Capitol Blvd, Suite 1900 | Boise, ID 83702-7705
Direct: (208) 387-4211 | Fax: (208) 389-9040
richard.hall@stoel.com | www.stoel.com

ORA Data Request 2.8

Do any of the terms of sale as part of the Transaction, including those covering the sale of the Fossil Rock Mine, discuss Bowie shipping coal to or through California? Please explain and provide the relevant citations.

Response to ORA Data Request 2.8

PacifiCorp objects to this request as overly broad, not reasonably calculated to lead to the discovery of admissible evidence; and as requesting information protected by the attorney-client privilege, attorney work product doctrine, or confidentiality agreement. Without waiving these objections, the Company responds as follows:

Nothing in the agreements substantively discusses Bowie shipping coal to or through California. A single reference to the "Stockton terminal" is made in one of the agreements as an example of how to calculate royalties under the relevant contractual definitions. Also, please note that as explained in the Company's response to ORA 1.1, the Fossil Rock assets are leases. It is not the Fossil Rock Mine as referred to in this question.

ORA Data Request 1.4

For the purposes of this data request, "the Transaction" should be understood to include all of the transactions related to or required to facilitate the transfer of PacifiCorp's Mining Assets to Bowie Resource Partners, LLC (Bowie) as proposed in A.15-09-007, including, without limitation, the transaction required to transfer ownership in the Fossil Rock Mine.

Please provide the known and probable reserves of the coal contained in the undeveloped Fossil Rock mine.

Response to ORA Data Request 1.4

PacifiCorp objects to this data request as overly broad, requesting information that is outside the scope of this proceeding, and not reasonably calculated to lead to the discovery of admissible evidence. The Transaction does include the sale of the assets of Fossil Rock Fuels LLC, a wholly owned subsidiary of the Company. However, these assets are not in California rates and would not be at issue before the California Public Utilities Commission. Furthermore, the Fossil Rock assets are coal leases, not the "Fossil Rock Mine." Without waiving this objection, the Company responds as follows:

Reserves in the undeveloped Fossil Rock coal leases at the time of the transaction were estimated at 41,660,000 tons.

ORA Data Request 1.7

For the purposes of this data request, "the Transaction" should be understood to include all of the transactions related to or required to facilitate the transfer of PacifiCorp's Mining Assets to Bowie Resource Partners, LLC (Bowie) as proposed in A.15-09-007, including, without limitation, the transaction required to transfer ownership in the Fossil Rock Mine.

On page 4, lines 9 – 11 of Ms. Crane's testimony, PacifiCorp states "Bowie has been recognized for its environmental stewardship and has a strong track record for a reduction of safety violations and lost-time safety incident rates".

Please provide evidence supporting these three assertions (environmental stewardship, reduction of safety violations, and reduction of lost-time safety incident rates).

Response to ORA Data Request 1.7

Please refer to the Bowie Resource Partners LLC website links (along with information copied from those links) below, showing information supporting the cited assertions:

http://bowieresources.com/safety/

Safety

Safety Is A Core Value

Safety is more than a priority at our mines, it is a core value that has been adopted and internalized by all of our employees. We pride ourselves on our exemplary safety records.

We consistently outperform the national average in number of safety violations

We consistently outperform the national average in lost-time safety incident rates

Our Awards

National Mining Association Sentinels of Safety Award

- Sufco: 2010, 2012
- Dugout Canyon: 2011
- Skyline: 2005, 2014

Sentinels of Safety Certificate of Achievement In Safety

- Dugout: 2012

Colorado Mining Association – Outstanding Safety Practices

- Bowie: 2007, 2008

Utah Mining Association – Safety Award

- Dugout: 2010-2014
- Skyline: 2010-2014
- Sufco: 2010-2012

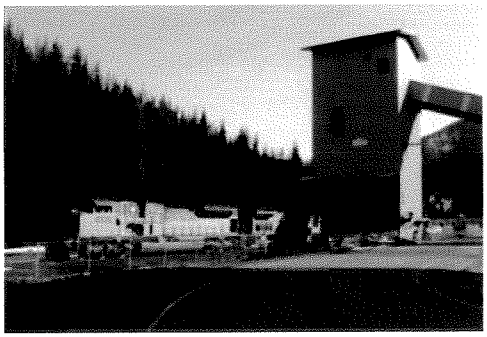
Rocky Mountain Coal Mining Institute Safety Award

- Dugout Canyon: 2011, 2012, 2014
- Skyline: 2007-2010, 2014
- Sufco: 2010, 2012

http://bowieresources.com/environment/

Environment

Environmental Stewardship



We are committed environmental custodians – we maintain the highest standards in mining methods and reclamation

We work hard to go further than environmental regulations require of us to protect our land, water, air and communities

- We employ sophisticated water management methods and technologies to reduce water demand, increase use of recycled water and to treat water prior to discharge back into the environment
- We deploy best-practice reclamation solutions to optimize the lands future use

We have received numerous environmental awards:

- Sufco and Skyline received the Utah Board of Oil, Gas and Mining awards for environmental excellence
- Sufco and Skyline have perfect environmental compliance rates 6 years running
- Skyline and Sufco have received numerous Utah Earth Day awards
- Bowie has been recognized by the Colorado Division of Minerals and Geology for environmental stewardship
- Bowie received the Excellence in Reclamation Award twice
- Bowie was awarded the Subsidence Impact Evaluation Award and the Pollution Prevention Award

Our affiliates offer environmental control technologies and services

- Bowie Refined Coal LLC
- ClearStack Power LLC

ORA Data Request 1.3

For the purposes of this data request, "the Transaction" should be understood to include all of the transactions related to or required to facilitate the transfer of PacifiCorp's Mining Assets to Bowie Resource Partners, LLC (Bowie) as proposed in A.15-09-007, including, without limitation, the transaction required to transfer ownership in the Fossil Rock Mine.

Do any existing PacifiCorp mines, mines included as part of the Transaction, or known coal reserves owned by PacifiCorp have non-truck, surface route access (i.e. rail) to the Huntington or Hunter power plants?

For each mine or known reserve where the answer is 'yes,' please provide the name of the mine; precise location of the mine; the type of access; and the route number or other identifier for the access route.

Response to ORA Data Request 1.3

No. Currently, there is no non-truck (i.e. rail) access to the Huntington or Hunter power plants.

ORA Data Request 3.1

(a) Generally, does PacifiCorp consider Coal Supply Agreements (CSAs) or similar agreements when evaluating the economic/financial viability of coal-fired power plants? If so, please provide the appropriate procedures, best practices, etc.

(b) Has PacifiCorp ever extended the life of a coal-fired power plant due to a long-term CSA? (In the context of this question, please interpret "long-term" to mean greater than 5 years.) If so, please provide all covered analyses and supporting work papers.

Response to ORA Data Request 3.1

(a) Yes. The Company evaluates pricing and other terms of coal supply agreements when evaluating the economic viability of major capital investments for coal-fired plants relative to alternatives. These analyses generally evaluate the cost to install emission control equipment relative to other compliance alternatives, which can include early retirement, change in dispatch, and fuel-switching. In these studies coal cost assumptions over the term of a coal supply agreement are based on the terms of the agreement and the specific assumptions of the scenario. This can include liquidated damages and/or costs associated with minimum take obligations, as applicable.

(b) No.

ORA Data Request 1.5

For the purposes of this data request, "the Transaction" should be understood to include all of the transactions related to or required to facilitate the transfer of PacifiCorp's Mining Assets to Bowie Resource Partners, LLC (Bowie) as proposed in A.15-09-007, including, without limitation, the transaction required to transfer ownership in the Fossil Rock Mine.

Please provide PacifiCorp's projections for operations and maintenance (O&M) expenses for the Huntington plant through 2025, with cost categories provided in a form that is as specific as available.

Response to ORA Data Request 1.5

Operations and maintenance (O&M) expense projections for the Huntington and Hunter plants through 2025 are provided in Attachment ORA 1.5. These projections are consistent with the data reflected for these plants in the 2015 Integrated Resource Plan Update issued March 31, 2016.

PacifiCorp

Total O&M (PacifiCorp Share)
(Thousands of Dollars)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Hunter Plant									
Labor	24,059	22,422	22,704	23,148	23,186	23,321	23,677	24,052	24,251	24,859
Chemicals	9,210	9,171	9,099	9,497	9,379	10,331	11,282	11,303	12,293	13,316
Other O&M	19,288	19,796	22,222	23,353	23,113	23,746	24,269	24,677	24,691	24,504
Special Maintenance	-	-	501	372	372	372	372	372	372	372
Overhauls	8,759	-	8,598	6,738	10,567	10,526	-	6,836	11,635	10,526
Total Excluding Fuel	61,316	51,389	63,124	63,108	66,617	68,296	59,600	67,240	73,242	73,577
Fuel Consumed	147,619	153,749	149,215	153,964	155,432	177,393	198,064	200,541	194,551	199,664
Total Including Fuel	208,935	205,138	212,339	217,072	222,049	245,689	257,664	267,781	267,793	273,241
	Huntington Plant									
Labor	21,516	20,441	19,521	19,947	20,638	20,050	20,842	20,376	21,194	20,957
Chemicals	5,707	5,704	5,645	5,794	6,094	6,370	7,431	7,656	8,239	8,433
Other O&M	14,022	12,624	14,037	14,061	14,057	14,267	13,986	14,070	14,107	14,168
Special Maintenance	-	-	-	-	-	-	-	-	-	-
Overhauls	-	-	10,236	10,335	-	-	10,615	12,166	-	-
Total Excluding Fuel	41,245	38,769	49,439	50,137	40,789	40,687	52,874	54,268	43,540	43,558
Fuel Consumed	131,559	133,425	127,805	130,281	139,315	139,665	133,105	138,498	147,521	151,100
Total Including Fuel	172,804	172,194	177,244	180,418	180,104	180,352	185,979	192,766	191,061	194,658

Trail Mountaim Mine

Permit Number: C0150009
Emery County, Utah

Previous Page

Site Summary

The Trail Mountain Mine is currently inactive. The Trail Mountain Mine is located on the eastern edge of the Wasatch Plateau Coal Field, approximately 12 miles west of Orangeville, Utah. Mining at or near the Trail Mountain Mine began in 1898 and a large-scale operation started in 1909. Mining continued until 1967 when the mine was shut down for ten years. The mine was re-opened in 1977 and has had several owners since then. The Trail Mountain Mine was purchased from Arco Coal in 1992 by PacifiCorp and is operated by Energy West Mining Company, a wholly owned subsidiary of PacifiCorp.

Site Description

The Trail Mountain Mine encompasses about 3,500 acres, a combination of fee lands and federal ownership. Mining was by longwall method in the Hiawatha seam with an annual production of about 4 million tons of coal. Coal produced from the Trail Mountain Mine was transferred via beltline through the Cottonwood/Wilberg Mine to the surface loading facilities located in Grimes Wash. The coal was loaded onto trucks and hauled to the Hunter Power Plant where it was used to produce electricity. Both the Trail Mountain Mine and the Cottonwood/Wilberg are in temporary cessation status as of 2001.

Mine Location Map Google Map

Last Updated: Nov 30 2006 12:10PM
By: pgrubaug

EX-2.1 2 a2225124zex-2_1.htm EX-2.1

Exhibit 2.1

ASSET PURCHASE AND SALE AGREEMENT
(FOSSIL ROCK ASSETS)

between

FOSSIL ROCK FUELS, LLC

and

FOSSIL ROCK RESOURCES, LLC

dated as of

December 12, 2014

Seller Exhibits and Disclosure Schedules

Exhibit A -	Form Overriding Royalty Agreement
Exhibit B -	PacifiCorp Guaranty
Schedule 1 -	Best of Seller's Knowledge
Schedule 2 -	Contracts
Schedule 3 -	Notice of Violation
Schedule 4 -	Permits
Schedule 5 -	Permitted Encumbrances
Schedule 6 -	Property Leases
Schedule 7 -	Pending Litigation
Schedule 8 -	Consents
Schedule 9 -	Hazardous Substances
Schedule 10 -	Notices of Default
Schedule 11 -	Bonds
Schedule 12-	Rental and Royalty Obligations

ASSET PURCHASE AND SALE AGREEMENT

THIS ASSET PURCHASE AND SALE AGREEMENT (this "***Agreement***") is made and entered into this 12th day of December, 2014 (the "***Effective Date***"), by and between FOSSIL ROCK FUELS, LLC, a Delaware limited liability company, having a mailing address of 1407 W. North Temple, Salt Lake City, Utah 84116 ("***Seller***"), and FOSSIL ROCK RESOURCES, LLC, a Delaware limited liability company, having a mailing address of 6100 Dutchmans Lane, 9th Floor, Louisville, Kentucky 40205 ("***Buyer***"). Seller and Buyer may be collectively referred to herein as the "***Parties***" or individually as a "***Party***."

RECITALS

A. WHEREAS, Seller is the owner of the Purchased Assets (as defined in Section 1.1); and

B. WHEREAS, Buyer desires to purchase and acquire Seller's interest in the Purchased Assets from Seller, and Seller desires to sell and convey its interest in the Purchased Assets to Buyer, all subject to and in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, in consideration of the foregoing premises, the mutual covenants and agreements hereinafter set forth, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged by the Parties, Seller and Buyer agree as follows:

ARTICLE I
DEFINITIONS

1.1 Certain Definitions. In this Agreement, capitalized terms and other defined terms described below shall have the meanings set forth or cross-referenced as follows:

"*Affiliate*" means any person, partnership, joint venture, corporation or other form of enterprise which directly or indirectly controls, is controlled by, or is under common control with, a Party hereto. For purposes of the preceding sentence, "control" (including the terms "controlled by" and "under common control with") means possession, directly or indirectly, of the power to direct or cause direction of management and policies through ownership of voting securities, contract rights, voting trust, or otherwise.

"*Agreement*" means this Asset Purchase and Sale Agreement and the Exhibit(s) and Schedules attached hereto (all of which Exhibit(s) and Schedules shall be deemed to be

incorporated herein by reference and made a part hereof as if set out in full herein), and all agreements or instruments executed in connection herewith, including the Closing Agreements.

"Assumed Liability" has the meaning given in Section 3.2(a).

"Basket" has the meaning given in Section 11.2(c).

"***Best of Seller's knowledge***" means the knowledge and belief of Seller, based solely upon the actual knowledge of the individuals listed on Schedule 1.

"***Bonds***" means the reclamation bonds provided to the Division as surety for reclamation of the Coal Leases (if any), and the performance bonds, if any, provided to the SITLA with respect to the Coal Leases or other state authorizations, all as described on Schedule 11.

"***Business Day***" means any day except Saturday, Sunday, or any other on which commercial banks located in Salt Lake City, Utah are authorized or required by Law to be closed for business.

"Buyer" has the meaning given in the Preamble.

"Cap" has the meaning given in Section 11.3.

"***Closing***" means the closing of this transaction which is described in more detail in Section 8.1.

"Closing Agreements" has the meaning given in Section 4.1(b)(i).

"***Closing Date***" has the meaning given in Section 8.1.

"***Closing Deadline***" has the meaning given in Section 8.1.

"***Coal Leases***" means Utah State Coal Leases ML-51191-OBA and ML-51192-OBA.

"Code" means the Internal Revenue Code of 1986, as amended.

"Consent" means any approval, consent, ratification, waiver, or other authorization.

"***Contracts***" means the agreements, contracts, personal property leases, purchase orders, and other agreements pertaining to the Purchased Assets, the subject matter of which is not real property (excluding the Coal Leases), as described on Schedule 2.

"***Division***" means the Division of Oil, Gas and Mining, Department of Natural Resources, State of Utah.

"Effective Date" has the meaning given in the Preamble.

"***Employee Liabilities***" means all Liabilities that relate to, are based on, or arise from Seller's or any of its Affiliates' current and former employees and applicants for employment, and their respective contractors' employees and applicants for employment, including, but not limited to, hiring obligations, pay obligations, successorship obligations, collective bargaining obligations, workers' compensation obligations, black lung obligations, and obligations relating to or arising under any Employee Plans, including without limitation any pension plan withdrawal or retiree medical liability.

"***Employee Plans***" means all (i) "employee benefit plans," as defined in Section 3(3) of ERISA, (ii) all "multiemployer plans," as defined in Section 3(37) or ERISA, (iii) all "nonqualified deferred compensation plans," as defined in Section 409A of the Code, and (iv) all bonus or other employment, incentive compensation, equity or equity-based compensation, deferred compensation, pension, profit sharing, retirement, stock purchase, stock option, stock ownership, stock appreciation rights, phantom stock, leave of absence, layoff, day or dependent care, legal services, cafeteria, life, health, medical, hearing, accident, disability, separation, severance pay, sick leave, vacation pay, salary continuation, disability, hospitalization, medical insurance, life insurance, scholarship plans, change of control, and collective bargaining agreement benefit plans, practices, programs, or agreements, whether written or oral, whether or not subject to ERISA, that Seller or any of its Affiliates sponsor, contribute to, or has any obligation or liability, contingent or otherwise, for the benefit of any of its or their employees or former employees, including, but not limited to, the United Mine Workers of American 1974 Pension Plan.

"Encumbrances" means any charge, claim, community property interest, deed of trust, condition, equitable interest, lien, mortgage, easement, encumbrance, servitude, right of way, option, pledge, purchase agreement, additional sale agreement, proxy, security interest, right of first refusal, or restriction of any kind, including any restriction on use, voting, transfer, receipt of income, or right of exercise of any other attribute of ownership.

"***ERISA***" means the Employment Retirement Income Security Act of 1974, as amended.

"***Escrow Agent***" has the meaning as given in Section 2.3.

"Excluded Liabilities" has the meaning given in Section 3.2(b).

"Exhibit(s)" means the exhibits attached hereto.

"Files and Records" means originals or copies, as determined by Seller and in its possession, of all files, reports, records, data, maps, and accounting records relating to the

Purchased Assets, including without limitation those relating to engineering, drilling, geology, mining, permitting, maintenance, inventory and supply, property and excise taxes, Royalties, and title, but excepting corporate records, market studies, coal sales records, income tax records, Seller's general land files, personnel records, economic analyses, and documents related to formulation of the terms and conditions of this Agreement and documents related to general policies and procedures of Seller and its Affiliates not directly related to the Purchased Assets.

"***Government Authority***" shall mean any national, state or local government or any subdivision, agency, court, commission, board, bureau or other authority thereof.

"Hazardous Substances" means any hazardous, toxic, radioactive, or infectious substance, material, or waste which is regulated by any Government Authority, including any substance, material, or waste which is defined as a "hazardous waste," "hazardous material," "hazardous substance," "extremely hazardous waste," "restricted hazardous waste," "contaminant," "toxic waste," or "toxic substance" under any provision of Law, and including petroleum, petroleum products, asbestos, presumed asbestos-containing material or asbestos-containing material, urea formaldehyde, and polychlorinated biphenyls.

"Indemnitee" has the meaning given in Section 10.3(b).

"Indemnitor" has the meaning given in Section 10.3(b).

"Law" means any statute, law, ordinance, regulation, rule, code, order, constitution, treaty, common law, judgment, decree, other requirement or rule of law of any Government Authority.

"Notice of Violation" or "NOV" has reference to those notices of violation listed in Schedule 3.

"***Overriding Royalty***" has the meaning given in Section 6.1.

"Party" or "Parties" has the meaning given in the Preamble.

"Permits" means the existing permits and applications for permits appurtenant or relating to the Purchased Assets as described on Schedule 4.

"Permitted Encumbrances" means those exceptions, conditions, encumbrances, liens, and interests described on Schedule 5.

"Property Leases" means the leases (other than the Coal Leases), rights-of-way, easements, licenses, and agreements pertaining to real property included in the Purchased Assets as described on Schedule 6.

"***Property Taxes***" has the meaning given in Section 8.3(a).

"Purchase Price" has the meaning given in Section 2.2.

"Purchased Assets" means all of Seller's right, title, and interest in the Property Leases, the Coal Leases (including prepaid rentals and Royalties thereunder to the extent transferable (subject to Section 8.3(c)), the Contracts, the Permits, the Files and Records, and any other easements, rights-of-way, roads, improvements, haul ways, leases, and options and other realty relating to the Purchased Assets.

"Royalties" means all royalties and overriding royalties payable to the respective lessors or others under the Coal Leases.

"Schedules" means Seller's disclosure schedules attached hereto.

"Seller" has the meaning given in the Preamble.

"***Seller's Disclosure List***" has the meaning given in Section 4.3.

"***SITLA***" means the Utah School and Institutional Trust Lands Administration.

"Tax" (including, with correlative meaning, the terms "Taxes," "Taxing," and "Taxable") shall mean all federal, state, local or foreign taxes, charges, fees, duties, imposts, levies or other similar assessments of any kind whatsoever imposed by any Government Authority (but excluding any Royalties payable to any Government Authority under any lease).

ARTICLE II
AGREEMENT TO PURCHASE AND SELL; PURCHASE PRICE

2.1 Agreement to Purchase and Sell. Subject to the terms and conditions set forth herein, at the Closing, Seller shall sell, assign, transfer, convey and deliver to Buyer, and Buyer shall purchase from Seller, all of the Purchased Assets, free and clear of all Encumbrances except the Permitted Encumbrances.

2.2 Purchase Price. As consideration for the sale of the Purchased Assets and the other obligations of Seller hereunder, on the Closing Date, Buyer shall pay to Seller, subject to adjustment pursuant to Section 8.3 below, **Thirty Million Dollars (USD $30,000,000.00)** (the "***Purchase Price***") in immediately available funds.

2.3 Escrow Agent. The Closing of the transaction contemplated by this Agreement shall be facilitated by First American Title Insurance Company, 215 South State Street, #380, Salt Lake City, Utah 84111 (the "***Escrow Agent***").

2.4 Purchase Price Allocation. The Purchase Price shall be allocated among the Purchased Assets in the manner determined by Buyer.

ARTICLE III
ASSETS TO BE SOLD AND PURCHASED

3.1 Assets to be Sold. The assets to be sold are the Purchased Assets.

3.2 Assumed Liabilities; Excluded Liabilities.

(a) Upon completion of the Closing, Buyer covenants and agrees to assume, fulfill, perform and in due course discharge, only the following obligations and liabilities (collectively, the "***Assumed Liabilities***"):

(i) The asset retirement and reclamation obligations, including but not limited to environmental remediation obligations, if any, with respect to the Purchased Assets, whether arising before or after the Closing Date, including the obligation to replace the Bonds;

(ii) The post-Closing obligations and liabilities of Seller under Coal Leases, the Property Leases, the Permits or the Contracts that, by their terms, arise after the Closing Date, relate to periods following the Closing Date, and are to be observed, paid, discharged or performed, as the case may be, at any time after the Closing Date (excluding, for the avoidance of doubt, any obligations under the Coal Leases, the Property Leases, the Permits or the Contracts arising from breaches thereof or otherwise on or prior to the Closing Date); and

(iii) All other obligations and liabilities relating to the Purchased Assets that, by their terms, arise after the Closing Date, relate to periods following the Closing Date, and are to be observed, paid, discharged or performed, as the case may be, at any time after the Closing Date.

(b) Buyer shall not assume any liability or obligation arising from or relating to a breach by Seller of a representation, warranty or covenant set forth in this Agreement. Furthermore, except for the Assumed Liabilities, Buyer shall not assume, and Seller shall remain liable, responsible for, and shall retain, and timely pay, perform and discharge, any and all other debts, obligations, and liabilities of Seller and its Affiliates, whether known, unknown, contingent, executory, fixed or otherwise, including without limitation, all Employee Liabilities and all pending litigation, if any, as described on Schedule 7. All of the matters referenced in this Section 3.2(b) shall be referred to as "***Excluded Liabilities***".

3.3 Possession; Risk of Loss; "As Is" Purchase. Possession of, risk of loss to, and responsibility for the Purchased Assets shall be delivered to Buyer on the Closing Date.

Notwithstanding any other term or condition of this Agreement, any and all risk of loss to and responsibility for the Purchased Assets shall remain with Seller until such time as the Closing shall have been consummated according to the terms and conditions of this Agreement.

UPON CLOSING, BUT WITHOUT QUALIFYING, WAIVING, LIMITING, OR RELEASING, OR OTHERWISE AFFECTING THE BUYER'S RIGHT TO RELY ON, THE REPRESENTATIONS, COVENANTS, WARRANTIES, INDEMNITIES, AND AGREEMENTS OF THE SELLER SET FORTH IN THIS AGREEMENT, THE BUYER SHALL HAVE CONDUCTED SUCH INVESTIGATIONS WITH RESPECT TO THE PURCHASED ASSETS AS THE BUYER DEEMS ADVISABLE, AND SHALL HAVE SATISFIED ITSELF WITH RESPECT TO THE CONDITION OF THE PURCHASED ASSETS, AND THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT. FURTHER, WITHOUT QUALIFYING, WAIVING, LIMITING, OR RELEASING, OR OTHERWISE AFFECTING THE BUYER'S RIGHT TO RELY ON, THE REPRESENTATIONS, COVENANTS, WARRANTIES, INDEMNITIES, AND AGREEMENTS OF THE SELLER SET FORTH IN THIS AGREEMENT AND EXCEPT AS MAY BE OTHERWISE AGREED BY THE BUYER AND THE SELLER, THE BUYER SHALL ACCEPT THE PURCHASED ASSETS IN THE CONDITION IN WHICH THEY EXIST UPON THE CLOSING (THAT IS, "AS IS" AND "WHERE IS", "WITH ALL FAULTS"), WITHOUT ANY OTHER REPRESENTATION OR WARRANTY, EXPRESS OR IMPLIED, IN FACT OR BY LAW.

ARTICLE IV
REPRESENTATIONS AND WARRANTIES

4.1 Representations and Warranties of Seller. Seller represents and warrants to Buyer that the items set forth below in this Section 4.1 are and shall be true and correct as of the date hereof and as of the Closing Date:

(a) **Corporate Standing**. Seller is a limited liability company duly organized and validly existing and in good standing under the laws of the State of Delaware, has corporate power to execute, deliver, and carry out the terms and provisions of this Agreement, and to carry on its business as now being conducted; and as necessary, is duly qualified to do business in and is in good standing in the State of Utah.

(b) **Authorizations; Binding Agreements; Consents; Non-Contravention**.

(i) The execution, delivery and performance of this Agreement by Seller and each conveyance, assignment, agreement, and other document herein contemplated to be executed by Seller, has been duly authorized by all necessary corporate action. This Agreement and the specific conveyances, assignments, agreements, and other documents (collectively, the "***Closing Agreements***") contemplated herein to be

executed by Seller are, or will be upon execution, legal, valid and binding obligations of Seller, duly enforceable against Seller in accordance with their terms. Seller has the absolute and unrestricted right, power, and authority to execute, deliver, and, subject to any Consents as set forth in Schedule 8, perform its obligations under this Agreement and the Closing Agreements.

(ii) Except as set forth on Schedule 8, no Consent, approval, action or authorization of any third party, or application to, or other notice or filing with, a third party, including any Government Authority, is required for the execution, delivery or performance of this Agreement or the Closing Agreements or the consummation of the transactions contemplated hereby or thereby by Seller.

(iii) Seller's execution, delivery, and performance of this Agreement and the Closing Agreements do not and will not result in any violation of or be in conflict with the terms of Seller's Certificate of Formation or Limited Liability Company Agreement; and subject to any Consents set forth on Schedule 8, do not and will not violate or conflict with any permit, lease, venture, mortgage, agreement, contract, judgment, order or other obligation or restriction to which Seller or the Purchased Assets may be bound or encumbered.

(c) **Taxes.** All Tax returns and reports relating to the Purchased Assets required by Law (including, without limiting the scope of the foregoing, all federal, state, and local property Tax, severance and franchise Tax laws) to be filed by Seller prior to the Closing have been duly filed or will be caused to be filed and the Taxes due thereunder paid, if any.

(d) **Brokers or Finders Fees.** No obligation or liability, contingent or otherwise, for brokers or finder's fees, agents' commissions, or similar payments created by Seller with respect to the matters provided for in this Agreement shall be imposed upon Buyer.

(e) **No Imposition of Liens.** The consummation of the sale by Seller shall not result in the imposition of any Encumbrance upon any of the Purchased Assets.

(f) **Title to Purchased Assets.** Subject to the Permitted Encumbrances, Seller owns the Purchased Assets, free and clear of any Encumbrances (other than Taxes not yet due and payable and with exception of Seller's general corporate mortgage, which shall be released as to the Purchased Assets prior to Closing).

(g) **Applicable Contracts.** The Coal Leases, the Contracts, the Permits, and the Property Leases are the only material agreements to which the Purchased Assets are bound. There are no renegotiations or amendments of, attempts to renegotiate or amend, or outstanding

rights to renegotiate or amend any of the Coal Leases, the Contracts, the Permits or the Property Leases.

(h) **Pending Litigation.** Except for any Notice(s) of Violation disclosed in Schedule 3 and any pending litigation as disclosed on Schedule 7, (i) there are no actions, suits, arbitrations, or proceedings currently pending against or affecting the Purchased Assets, and (ii) to the Best of Seller's knowledge, there are no claims or threatened claims against or liabilities affecting the Purchased Assets.

(i) **No Default of Orders, Etc.** There is no order, judgment, writ, injunction, decree or award of any court or arbitrator that affects the Purchased Assets.

(j) **Compliance with Laws and Regulations.** Seller is in material compliance with all currently effective applicable Laws as currently interpreted by regulatory agencies concerning the Purchased Assets. Except as disclosed on Schedule 3, Seller has not received or has any knowledge of any actual or threatened order, notice, citation, directive, summons, warning, or other communication from any Government Authority or from any private citizen acting in the public interest or from any prior owner or operator of the Purchased Assets or any other third person of any actual or potential violation or failure to comply with any applicable Laws.

(k) **Hazardous Substances**. To the Best of Seller's knowledge, except as disclosed on Schedule 9, (i) no

Hazardous Substance has been disposed of, spilled, leaked or otherwise released on, under or from the properties included in the Purchased Assets in a reportable quantity; (ii) no wastes in reportable quantities (including without limitation garbage and refuse) have been disposed of on the properties included in the Purchased Assets; and (iii) there are no underground storage tanks on the properties included in the Purchased Assets. There is no PCB-bearing equipment on the land subject to the Coal Leases or included as part of the Purchased Assets.

(l) **Status of Coal Leases/Contracts/Property Leases.** The Coal Leases, the Contracts and the Property Leases are valid and in good standing, and, except as disclosed to Buyer on Schedule 10, there is no default thereunder. Except as disclosed on Schedule 10, Seller has received no notice of default under any Contract, Coal Lease or Property Lease. The Coal Leases, the Contracts and the Property Leases constitute all of the agreements and leases in which Seller has an interest relating to the Coal Leases. Schedule 12 attached hereto lists all of the minimum rental and Royalty obligations under the Coal Leases.

(m) **Validity of Permits**. The Permits, except as disclosed on Schedule 3, are valid and in full force and effect. Except as set forth in Schedule 3, Seller is in compliance with the Permits, except only such violations and instances of noncompliance as, separately and in the aggregate, are not material to the value of the Purchased Assets and have been completely abated

prior to the date hereof. The Permits are the only permits, approvals, authorizations or licenses necessary to permit Seller to lawfully conduct and operate its business on the Real Property.

4.2 Limitation of Warranties and Representations. Neither Seller nor its Affiliates make, or have made, any representation or warranty, express or implied, concerning or related to the Purchased Assets, except as expressly provided in Section 4.1. Buyer has conducted, at its sole cost and expense, its due diligence examination of the Purchased Assets as Buyer deemed appropriate. Buyer has relied on its investigation and on the representations and warranties set forth herein in entering into this Agreement. NOTWITHSTANDING ANY OTHER PROVISION OF THIS AGREEMENT TO THE CONTRARY, SELLER EXPRESSLY DISCLAIMS ANY REPRESENTATION OR WARRANTY WITH RESPECT TO THE QUANTITY, QUALITY, MINEABILITY, MERCHANTABILITY, OR MARKETABILITY (INCLUDING WITHOUT LIMITATION EXTRACTION AND REMOVAL COSTS) OF THE COAL LOCATED IN, ON OR UNDER THE PURCHASED ASSETS OR AS TO QUALITY, MERCHANTABILITY, OR MARKETABILITY OF ANY COAL THAT MIGHT BE EXTRACTED THEREFROM.

4.3 Changes Prior to Closing. Up to ten (10) days prior to the Closing, Seller shall provide Buyer with a list of any knowledge acquired or events occurring after the Effective Date that cause Seller's representations and warranties in Section 4.1 to be untrue in any material respect or are reasonably likely to cause them to be untrue in any material respect ("***Seller's Disclosure List***"). The Seller's Disclosure List shall not be deemed to (i) amend or supplement the Schedules for purposes of the conditions to Closing provided in Section 7.2, or (ii) prevent or cure any misrepresentation or breach of a warranty or covenant contained herein.

4.4 Representations and Warranties of Buyer. Buyer represents and warrants that the items set forth below in this Section 4.4 are and shall be true and correct as of the date hereof and as of the Closing Date:

(a) **Corporate Standing**. Buyer is a limited liability company duly organized, validly existing, and in good standing under the laws of the State of Delaware, has corporate power to execute, deliver, and carry out the terms and provisions of this Agreement; to carry on its business as now being conducted; and as necessary is qualified to do business and is in good standing in the State of Utah.

(b) **Authorizations; Binding Agreements; Consents; Non-Contravention**.

(i) The execution, delivery and performance of this Agreement by Buyer and each conveyance, assignment, agreement, and other document herein contemplated to be executed by Buyer, has been duly authorized by all necessary corporate action. This Agreement and the Closing Agreements to be executed by Buyer are, or will be upon execution, legal, valid and binding obligations of Buyer, duly enforceable against

Buyer in accordance with their terms. Buyer has the absolute and unrestricted right, power, and authority to execute, deliver, and perform its obligations under this Agreement and the Closing Agreements.

(ii) No Consent, approval, action or authorization of any third party, or application to, or other notice or filing with, a third party, including any Government Authority, is required for the execution, delivery or performance of this Agreement or the Closing Agreements or the consummation of the transactions contemplated hereby or thereby by Buyer.

(iii) Buyer's execution, delivery, and performance of this Agreement and the Closing Agreements do not and will not result in any violation of or be in conflict with the terms of Buyer's Certificate of Formation or Limited Liability Company Agreement; and subject to any Consents, do not and will not violate or conflict with any permit, lease, venture, mortgage, agreement, contract, judgment, order or other obligation or restriction to which Buyer may be bound or encumbered.

(c) **No Brokers or Finders Fees.** No obligation or liability, contingent or otherwise, for brokers or finder's fees, agents' commissions, or similar payments created by Buyer with respect to the matters provided for in this Agreement shall be imposed upon Seller.

ARTICLE V
CONDUCT OF BUSINESS

5.1 Operations by Seller. Seller and Buyer recognize that no production of coal is or will be conducted by Seller on the Coal Leases prior to the Closing Date. The following provisions shall govern any activities conducted on or related to the Purchased Assets after the Effective Date and prior to the Closing Date:

(a) Seller will, or cause its contractor to, maintain the Purchased Assets in compliance with regulatory, local land use, and environmental protection requirements.

(b) Seller will, subject to Section 5.3, cooperate prior to the Closing in orienting Buyer's personnel to the Purchased Assets.

(c) Subject to the reimbursement provision under Section 8.3(c), Seller shall pay or otherwise satisfy in the ordinary course of its business all liabilities and obligations associated with or related to the Purchased Assets.

5.2 Seller's Covenants. Pending the Closing, Seller shall:

(a) (i) not directly or indirectly entertain, solicit, initiate, accept or encourage any inquiries, offers or proposals from, discuss or negotiate with, provide any non-public information to, or consider the merits of any unsolicited inquiries or proposals from, any person (other than Buyer and its Affiliates) relating to any transaction involving the sale or lease of any of the Purchased Assets, and (ii) not participate in any discussions or negotiations regarding, furnish any information with respect to, assist or participate in, or facilitate in any other manner any effort or attempt by any person to do or seek, any of the foregoing;

(b) not enter into any contract or commitment relating to the Purchased Assets, or cancel or modify or in any way impair any of the Contracts, Coal Leases, the Permits or Property Leases.

5.3 Access by Buyer. Buyer and its duly authorized agents, employees and representatives, at their sole risk and expense, shall have reasonable access to the Purchased Assets for familiarization and orientation purposes upon two (2) days' notice to Seller. Buyer agrees to indemnify, defend, and hold harmless Seller and its directors, officers, agents, representatives, subsidiaries and Affiliates with respect to such activities in accordance with Section 10.2.

5.4 Confidentiality. All information provided by Seller to Buyer will be kept confidential and will not, without the prior written consent of the Seller, be disclosed by the Buyer or its representatives, in any manner whatsoever, in whole or in part, and will not be used by Buyer or its representatives directly or indirectly for any purpose other than evaluating the Purchased Assets and closing the transaction contemplated by this Agreement. Moreover, Buyer agrees to transmit the information only to those representatives who need to know the information for the purpose of evaluating and closing the transaction contemplated by this Agreement and who agree to be bound by the terms of this Agreement. Buyer will be responsible for any breach of this Agreement by its representatives. The information is supplied for informational purposes only and Seller makes no representations or warranties either express or implied, concerning the completeness or accuracy of the information except as specifically set forth herein. Further, all information provided by Buyer to Seller will be kept confidential and will not, without the prior written consent of the Buyer, be disclosed by Seller or its representatives, in any manner whatsoever, in whole or in part, and will not be used by Seller or its representatives directly or indirectly for any purpose other than evaluating and closing the transactions contemplated by this Agreement. Moreover, Seller agrees to transmit the information only to those representatives who need to know the information for the purpose of evaluating and closing the transaction contemplated by this Agreement and who agree to be bound by the terms of this Agreement. Seller will be responsible for any breach of this Agreement by its representatives. The information is supplied for informational purposes only and Buyer makes no representations or warranties either express or implied, concerning the completeness or accuracy of the information except as specifically set forth herein. The obligations of confidentiality, non-disclosure and limited use imposed by this Agreement shall not apply to information, data or materials that are required to be disclosed to a Governmental

Authority or in connection with any regulatory approval process of any state public utility/service commission with jurisdiction over the Seller's, or its Affiliate's, business operations.

5.5 Joint Obligations. The following shall apply with equal force to Seller and Buyer:

(a) Neither Party shall intentionally perform any act which, if performed (or omit to perform any act which, if omitted to be performed) would prevent or excuse the performance of this Agreement by either Party hereto or which, except as a result of the conduct of the business in the usual and ordinary course, would result in any representation or warranty herein contained being untrue in any material respect if made on and as of the Closing.

(b) Buyer and Seller agree to cooperate with each other and to use reasonable efforts to obtain all other governmental and third party consents and approvals necessary to complete the transactions contemplated by this Agreement.

ARTICLE VI
OVERRIDING ROYALTY

6.1 Overriding Royalty Payment. Concurrent with the Closing, Buyer shall grant to Seller's Affiliate, PacifiCorp, a Four Percent (4.0%) overriding royalty (the "***Overriding Royalty***") on the gross sales revenue from the sale of all coal mined from the Coal Leases, FOB the coal source, pursuant to an overriding royalty agreement substantially in the form attached hereto as Exhibit A, which shall be executed at the Closing and filed of record following the Closing.

6.2 Guaranty. Concurrent with the Closing, Seller shall cause its Affiliate, PacifiCorp, to execute a guaranty in favor of Buyer in the form attached hereto as Exhibit B ("***Guaranty***").

ARTICLE VII
CONDITIONS PRECEDENT TO CLOSING; TERMINATION

7.1 Conditions Precedent to the Obligations of Seller. The obligation for Seller to consummate the transactions contemplated by this Agreement is subject to the satisfaction, on or prior to the Closing, of the following conditions (any one or more of which may be expressly waived in writing by Seller):

(a) Seller, or its Affiliate, shall have obtained all necessary regulatory approvals of the transfer of the Purchased Assets to Buyer, on conditions acceptable to Seller in its sole discretion, including, but not limited to, the approval of any state public utility/service commission with jurisdiction over Seller's, or its Affiliate's, business operations.

(b) No proceeding shall have been instituted before any Government Authority by any person (other than a Party hereto) (i) making any challenge to, or seeking damages or other relief in connection with, the transactions contemplated by this Agreement, or (ii) that may have the effect of restraining, enjoining or prohibiting, making illegal or otherwise interfering with such transactions.

(c) The representations and warranties of Buyer contained herein shall have been true in all material respects when made and shall be true in all material respects as if originally made on and as of the Closing, without giving effect to any limitation or qualification as to "materiality" (including the word "material").

(d) Buyer shall have performed and complied in all material respects with all agreements and conditions required by this Agreement to be performed and complied with prior to or at Closing.

(e) All deliveries by Buyer set forth in Section 8.2 shall have been made.

(f) The "Effective Date" under the Coal Supply Agreement for the Huntington Power Plant between an Affiliate of Seller and an Affiliate of Buyer shall have occurred (either prior to or concurrent with the Closing).

7.2 Conditions Precedent to the Obligations of Buyer. The obligation of Buyer to consummate the transaction contemplated by this Agreement is subject to the satisfaction, on or prior to the Closing, of the following conditions (any one or more of which may be waived in writing by Buyer):

(a) Seller, or its Affiliate, shall have obtained all necessary regulatory approvals of the transfer of the Purchased Assets to Buyer, including, but not limited to, the approval of any state public utility/service commission with jurisdiction over Seller's, or its Affiliate's, business operations.

(b) No proceeding shall have been instituted before any Government Authority by any person (other than a Party hereto) (i) making any challenge to, or seeking damages or other relief in connection with, the transactions contemplated by this Agreement, or (ii) that may have the effect of restraining, enjoining or prohibiting, making illegal or otherwise interfering with such transactions.

(c) The representations and warranties of Seller contained herein shall have been true in all material respects when made and shall be true in all material respects as if originally made on and as of the Closing, without giving effect to any limitation or qualification as to "materiality" (including the word "material").

(d) Seller shall have in all material respects performed and complied with all agreements and conditions required by this Agreement to be performed or complied with prior to or at Closing.

(d) All deliveries by Seller set forth in Section 8.2 shall have been made.

(e) The "Effective Date" under the Coal Supply Agreement for the Huntington Power Plant between an Affiliate of Seller and an Affiliate of Buyer shall have occurred (either prior to or concurrent with the Closing).

(f) Between the Effective Date and the Closing Date, there shall have been (i) no material adverse federal or state legislative or regulatory change affecting the Purchased Assets or Buyer's ability to operate the same, and (ii) no material damage or loss to the Purchased Assets.

7.3 Termination.

(a) This Agreement may be terminated prior to the Closing as follows:

(i) at the election of the Seller, if any one or more of the conditions to the obligation of Seller to close has not been fulfilled as of the Closing Deadline, in which event Seller shall provide written notice of termination to Buyer;

(ii) at the election of the Buyer, if any one or more of the conditions to the obligation of Buyer to close has not been fulfilled as of the Closing Deadline, in which event Buyer shall provide written notice of termination to Seller;

(iii) at the election of the Seller, if the Buyer has breached any representation, warranty, covenant or agreement contained in this Agreement, which breach would have a material adverse effect on the transaction contemplated by this Agreement and which cannot be or is not cured by the Closing Deadline, in which event Seller shall provide written notice of termination to Buyer;

(iv) at the election of the Buyer, if the Seller has breached any representation, warranty, covenant, or agreement contained in this Agreement, which breach would have a material adverse effect on the transaction contemplated by this Agreement and which cannot be or is not cured by the Closing Deadline, in which event Buyer shall provide written notice of termination to Seller;

(v) at any time on or prior to the Closing Date, by mutual written consent of the Seller and the Buyer.

7.3 Effect of Termination. Each Party's right of termination under Section 7.3 is

in addition to any other rights it may have under this Agreement or otherwise, and the exercise of such right of termination will not be an election of remedies. If this Agreement is terminated pursuant to Section 7.3, all obligations of the Parties will terminate, except the provisions of Sections 5.4 and 11.1. A Party who terminates this Agreement pursuant to Section 7.3 shall have no liability to the other Party in respect of such termination.

ARTICLE VIII
CLOSING

8.1 Time and Place of Closing. Subject to the terms and conditions of this Agreement, the purchase and sale of the Purchased Assets contemplated hereby shall take place at a closing (the "***Closing***") to be held at 9:00 a.m., Salt Lake City, Utah time, no later than ten (10) Business Days after the last of the conditions to Closing set forth in Section 7.1 and 7.2 have been satisfied or waived (other than conditions which, by their nature, are to be satisfied on the Closing Date), but in no event later than May 31, 2015 ("***Closing Deadline***"), at the offices of Stoel Rives LLP, 201 South Main Street, Suite 1100, Salt Lake City, Utah 84111, or at such other time or on such other date or at such other place as Seller and Buyer may mutually agree upon in writing (the day on which the Closing takes place being the "***Closing Date***").

8.2 Actions at Closing. At the Closing, the following events shall occur, each being a condition precedent to the other and each being declared to have occurred simultaneously with the other:

(a) Buyer shall pay to Seller the Purchase Price due on the Closing Date by transferring the amount thereof in immediately available funds, by bank-to-bank wire transfer to the account set up by the Escrow Agent.

(b) Seller shall execute, acknowledge and deliver to Buyer the deeds, assignments and other documents necessary to transfer all of Seller's right, title, and interest in and to the Purchased Assets to Buyer free and clear of all Encumbrances, other than Permitted Encumbrances, and complete the transaction as anticipated under this Agreement.

(c) Subject to Section 9.3, Seller shall deliver original executed copies of all Consents (if any) to the assignment of the Contracts and the Property Leases and any other necessary Consents.

(d) The Seller and Buyer shall execute such documents and certificates evidencing (i) the accuracy of the representations and warranties included in Article IV of this Agreement, (ii) Seller's and Buyer's performance of or compliance with any covenant or obligation required to be performed hereunder, and (iii) the satisfaction of any conditions precedent to Seller's or Buyer's obligations hereunder. Such documents may also include, without limitation, closing statements, reflecting the adjustments, payments and credits described in this Agreement. Seller

and Buyer shall take such other actions as are reasonably necessary and appropriate to effectuate the Closing in accordance with this Agreement.

(e) The Parties (or their Affiliates) shall execute the Overriding Royalty and the Guaranty.

8.3 Adjustments to Purchase Price.

(a) All ad valorem taxes, real property taxes, personal property taxes, and similar obligations ("***Property Taxes***") with respect to the tax year in which the Closing occurs shall be apportioned as of the Closing Date between Seller and Buyer. Prorations shall be made as of the Closing Date, and appropriate credit shall be given for the Property Taxes and other similar matters based upon 2014 or, if then available, 2015 taxes for the real property.

(b) The collective amount of Property Taxes to be prorated in subpart (a) of this section will be calculated by the Seller on a state-specific basis by multiplying the net book value of the Purchased Assets by an assessment ratio and then by a composite state-wide property tax rate. The applicable assessment ratio will be calculated by dividing the net book value of all state assessed property by the assessed value of the Purchased Assets prior to any adjustment for state specific exemptions. The applicable state-wide property tax rate will be calculated by dividing the amount of Property Taxes paid for state assessed property for the most recent year by the corresponding assessed value of the Purchased Assets.

(c) Under the terms of the Coal Leases, an advanced minimum royalty payment of approximately One Million Four Hundred Thousand Dollars ($1,400,000) is due on or before January 18, 2015. In the event the Closing is not completed by January 18, 2015, Seller will pay such royalty on or before the due date. At Closing, the Purchase Price will be increased to reimburse Seller for said royalty payment, prorated based on the January 18th due date, acknowledging that such minimum royalty is amortized over a period of one (1) year from January 18, 2015. Except as provided in this Section 8.3(c), Seller waives any rights it may have to any rentals or royalties paid prior to the Closing.

(d) Seller shall pay any sales taxes assessed upon transfer of any of the Purchased Assets.

(e) Seller and Buyer shall split equally all escrow and closing fees charged by the Escrow Agent.

8.4 Post-Closing Adjustments. Except as provided in such Section 8.3(a), the Parties will determine adjustments referenced in Section 8.3, to the extent they have not been completed at the Closing, within ninety (90) days after the Closing and cause payment of appropriate funds to be made to either Buyer or Seller, as the case may be.

ARTICLE IX
PRIOR APPROVALS

9.1 Consent by SITLA. The Parties acknowledge that the assignments of the Coal Leases are subject to consent by SITLA. In the event SITLA consent to the assignment of the Coal Leases is not obtained prior to Closing, Buyer shall submit the assignments of the Coal Leases to SITLA within ten (10) days after the Closing Date for approval and will provide replacement bonds or other forms of a guarantee for any of the Bonds related to the Coal Leases. Pending such approval, Seller shall hold its interest in the Coal Leases solely for the benefit of Buyer, and Buyer shall be entitled to all of the benefits thereof and shall assume and be responsible for all liabilities, burdens and obligations thereunder, except for Excluded Liabilities related thereto. Seller shall execute such documents and take such other actions as may be reasonably necessary to effectuate the transfer of the Coal Leases to Buyer. NOTWITHSTANDING THE FOREGOING, BUYER SHALL NOT BE PERMITTED TO CONDUCT OPERATIONS UNDER COAL LEASES UNTIL THE ASSIGNMENT FROM SITLA HAS BEEN APPROVED AND THE REPLACEMENT BONDS OR OTHER FORMS OF GUARANTEE HAVE BEEN ACCEPTED BY SITLA.

9.2 Permits. Seller and Buyer shall make every reasonable effort before the Closing to obtain approvals for transfer of all Permits. After the Closing, Buyer shall make every reasonable effort to effect transfer of all Permits and replace all Bonds (if any), and if necessary, make applications for new permits to replace the obligations on the existing Permits, with any cost or expense associated with such transfer or application being for the account of Buyer. Buyer shall submit applications for transfer of the Permits or new permits related to the Purchased Assets and post replacement bonds therefor no later than ten (10) days after the Closing Date. Seller shall cooperate with Buyer in all its efforts to apply for and obtain approvals for transfer of all Permits. UNTIL APPROVAL OF THE TRANSFER OF THE PERMITS BY THE DIVISION, BUYER SHALL NOT BE PERMITTED TO CONDUCT OPERATIONS AT THE COAL LEASES. Notwithstanding the deferred transfer of any of the Permits to Buyer, or receipt of necessary consents, Buyer shall assume all responsibilities and liabilities under the Permits as of the Closing Date except for any Excluded Liabilities related thereto.

9.3 Contracts and Property Leases. In the event that any of the Contracts or Property Leases cannot validly be assigned to Buyer at or before the Closing Date, Buyer shall have the option to waive the conditions of Closing with respect to such unassignability. Any such consent shall not be a condition to Closing if the unassignable Contract or Property Lease, as applicable (i) is not material to the operation of the Purchased Assets, and (ii) if Seller delivers to Buyer at Closing its written assurance and agreement, in such form as Buyer's counsel may reasonably request, to the effect that Seller, until such time as Seller obtains the necessary consent to assignment of and assigns such Contract or Property Lease;

(a) can and will maintain such contract in full force and effect for its duration;

(b) will provide to Buyer the full benefit thereof; and

(c) will accord to Buyer all of Seller's rights and privileges thereunder and exercise all such right for the benefit and at the direction of Buyer without additional cost or expense to Buyer on account thereof, provided that Buyer performs or tenders to Seller performance of all of the obligations of Seller (other than ministerial or administrative acts which by their nature can reasonably be performed only by Seller) required by the terms of such contract to avoid a material breach thereof by Seller.

ARTICLE X
INDEMNIFICATION

10.1 Obligations of Seller. Seller shall indemnify, defend and hold harmless Buyer and its Affiliates and their respective directors, officers, managers, agents, representatives, subsidiaries, successors and assigns from and against any and all claims, demands or suits (by any party, including without limitation, any governmental agency), losses, liabilities, damages, obligations, payments, costs and expenses (including, without limitation, the costs and expenses of defending any and all actions, suits, proceedings, demands and assessments which shall include reasonable attorneys' fees and court costs) resulting from, relating to, arising out of, or incurred in connection with any of the following:

(a) Any breach by Seller of any of Seller's representations or warranties contained in this Agreement;

(b) Any breach by Seller of any of Seller's covenants contained in this Agreement; and

(c) All Excluded Liabilities.

10.2 Obligations of Buyer. Buyer shall indemnify, defend, and hold harmless Seller and its parent corporation, and their respective directors, officers, agents, representatives, subsidiaries and Affiliates, from and against any and all claims, demands, or suits (by any party including, without limitation, any governmental agency), losses, liabilities, damages, obligations, payments, costs and expenses (including, without limitation, the original costs of defending any and all actions, suits, proceedings, demands and assessment which shall include reasonable attorneys' fees and court costs) resulting from, relating to, arising out of or incurred in connection with any of the following:

(a) Any breach by Buyer of any of Buyer's representations or warranties contained in this Agreement;

(b) Any breach by Buyer of any of Buyer's covenants contained in this Agreement; and

(c) All Assumed Liabilities.

10.3 Indemnity Procedures.

(a) Notwithstanding any provision to the contrary included in this Article X, each Party hereto waives the right, for itself and its respective Affiliates, to be indemnified by the other Party hereto to the extent of any insurance proceeds or other recovery it receives with respect to the liabilities for which indemnification would otherwise be required hereunder. (For the purposes of this paragraph, insurance proceeds shall not include any payments received pursuant to an insurance program under which the Party seeking indemnification or an Affiliate of such Party bears the ultimate cost.)

(b) A Party claiming indemnification under this Article X (the "***Indemnitee***") shall notify in writing the Party from whom indemnification is claimed (the "***Indemnitor***") in reasonable detail of the nature, basis, and estimated amount of the claim within a reasonable time after discovery by the Indemnitee of the basis therefor or the assertion thereof by a third party against the Indemnitee. Notice of a claim filed in any court or administrative agency, or submitted to arbitration, shall be given to the Indemnitor within ten (10) days of the Indemnitee's receipt of such filing, but failure to provide notice within the ten (10) days shall not result in forfeiture of indemnification rights except to the extent that the ability of the Indemnitor to defend against the claim is materially impaired. In the event of such notice by the Indemnitee to the Indemnitor of a third party claim, the Indemnitor shall have twenty (20) days after receipt thereof in which to admit or deny responsibility for indemnification of the Indemnitee by written notice to the Indemnitee, and

(i) as to claims with respect to which the Indemnitee and the Indemnitor may share responsibility, each Party may elect to participate in the defense of the claim through counsel of its choice and at its expense, and neither Party shall settle or compromise the claim without the consent of the other; and

(ii) if the Indemnitor denies responsibility or fails to admit or deny responsibility for a claim within twenty (20) days of the notice, the Indemnitee shall have the sole option and right to defend the claim, including the right to settle or compromise the claim, by counsel of its choice.

(c) The Indemnitee shall give to the Indemnitor full access to investigate the subject matter of the claim and, at the request of the Indemnitor, to allow it at its own expense to participate in, or have the conduct of (as it may elect), all proceedings of whatsoever nature against the relevant third party arising out of, or in connection with, such liability or dispute.

ARTICLE XI
REMEDIES AND SURVIVAL

11.1 Survival of Representations and Warranties; Right to Indemnification. Subject to the provisions of this Article XI, all of the representations and warranties of the Parties contained in Article IV of this Agreement shall survive Closing for a period of eighteen (18) months, except for the representations and warranties in Section 4.1(c) which shall survive for the applicable statute of limitations. All covenants of the Parties in this Agreement will survive the Closing without limitation. The right to indemnification, reimbursement, or other remedy based upon such representations, warranties, covenants, and agreements shall not be affected by any investigation (including environmental investigation or assessment) conducted with respect to, or any knowledge acquired or capable of being acquired) at any time, whether before or after the Effective Date or the Closing Date, with respect to the accuracy or inaccuracy of or compliance with any such representation or warranty, or on the performance of or compliance with any covenant or agreement.

11.2 Limitation. An Indemnitor shall not be liable in respect of any claim for breach of any representation or warranty under Sections 10.1(a) or 10.2(a) made by an Indemnitee under this Agreement or in any certificates or documents delivered at Closing:

(a) if the subject matter of the claim was disclosed in the Schedules;

(b) unless written notice of the claim, specifying in reasonable detail the matter which gives rise to the claim, the nature of the breach and the amount claimed in respect thereof, shall have been given by the Indemnitee to the Indemnitor within eighteen (18) months after the Closing Date, except with respect to claim for a breach of a representation or warranty set forth in Section 4.1(c) which may be brought at any time prior the expiration of the applicable statute of limitations;

(c) subject to Section 11.3 below, unless the aggregate amount of the claimed liability in respect of all such breaches exceeds One Hundred Fifty Thousand Dollars and No/100 ($150,000.00) ("***Basket***"), at which time the Indemnitee may seek indemnification for all such breaches without regard to the Basket;

(d) to the extent that the Indemnitee is entitled to any savings or benefits as a result of such loss or to recover all or any portion of the claimed liability from any third party, whether by way of insurance proceeds (subject to Section 10.3(a)), reduction of taxes payable or otherwise;

(e) to the extent that such claim arises as a result of:

(i) any alteration in rates of taxation after the Closing with retrospective effect; or

(ii) the passing of, or any change in, any legislation after Closing.

(f) and to the extent that a claim is increased as a result of any of the matters set out in paragraph (e) above, the Indemnitor shall not be liable in respect of the amount by which the claim is so increased.

11.3 Maximum Amount. Except as provided below, the aggregate amount of the liability of the Seller for all claims with respect to the breach of any representations or warranties pursuant to Section 10.1(a) of this Agreement shall not exceed Nine Million Dollars ($9,000,000) ("***Cap***"). Except as provided below, the aggregate amount of the liability of the Buyer for all claims with respect to the breach of any representations or warranties pursuant to Section 10.2(a) of this Agreement shall not exceed the Cap. Notwithstanding anything contained herein to the contrary, the Parties agree that neither the Basket nor the Cap shall apply to a Party's obligation to indemnify another Party with respect to matters covered by Sections 10.1(b), 10.1(c), 10.2(b) or 10.2(c), as applicable, or to a Party's obligation to indemnify another party pursuant to Sections 10.1(a) or 10.2(a), as applicable, solely with respect to a breach of a representation or warranty relating to Sections 4.1(a), 4.1(b), 4.4(a) or 4.4(b).

ARTICLE XII
MISCELLANEOUS

12.1 Successors and Assigns; Assignment. This Agreement shall not be assignable, in whole or in part, directly or indirectly, by operation of law or otherwise, by either Party without the prior written consent of the other Party, provided that prior to the Closing, Buyer shall have the right to assign its rights and obligations under this Agreement to an Affiliate of Buyer. Subject to the foregoing, this Agreement shall be binding upon, and shall inure to the benefit of the Parties and their respective successors and permitted assigns.

12.2 Notices. All notices, payments and other communications to the Parties under this Agreement must be in writing, and shall be addressed respectively as follows:

Seller: PacifiCorp
c/o PacifiCorp Energy
825 NE Multnomah, Suite 600
Portland, OR 97232
Attn: Jeffery B. Erb
Email: jeff.erb@pacificorp.com

With a copy to: Stoel Rives LLP
201 S. Main Street, Suite 1100

Salt Lake City, UT 84111-4904
Attn: Richard R. Hall
Email: rrhall@stoel.com

Buyer: Fossil Rock Resources, LLC
6100 Dutchmans Lane, 9th Floor
Louisville, Kentucky 40205
Attn: Brian S. Settles
Email: bsettles@bowieresources.com

With a copy to: Van Cott, Bagley, Cornwall & McCarthy, P.C.
36 S. State Street, Suite 1900
Salt Lake City, Utah 84111
Attn: Kim S Colton
Email: kcolton@vancott.com

All notices shall be given (1) by personal delivery to the Party, (2) by e-mail transmission, with a copy to follow via overnight, certified or registered mail, return receipt requested, or (3) overnight mail or certified or registered mail, return receipt requested. All notices shall be effective and shall be deemed delivered (i) if by personal delivery or e-mail delivery or overnight delivery, on the date of delivery, and (ii) if by certified or registered mail, on the date delivered to the United States Postal Service as shown on the receipt. A Party may change its address from time to time by notice to the other Party.

12.3 Expenses and Fees. Each Party agrees to pay, without right of reimbursement from the other, the costs incurred by it incident to the preparation of this Agreement, and the fees and disbursements of counsel, accountants, and consultants employed by it in connection with the negotiation of this Agreement and the consummation of the transaction contemplated herein.

12.4 Public Announcements. Any public announcement, press release, or similar publicity with respect to this Agreement and the Closing will be issued, if at all, at such time and in such manner as the Parties mutually agree.

12.5 Waiver. Buyer or Seller, by written notice to the other, may: (i) extend a time for performance of any of the obligations or other actions of the other Party under this Agreement; (ii) waive by express written waiver any inaccuracy in the representations or warranties of the other Party contained in this Agreement or any document delivered pursuant to this Agreement; (iii) waive by express written waiver any compliance with the conditions or covenants of the other Party contained in this Agreement; or (iv) waive or modify by express written waiver or agreement performance of any of the obligations performed by the other Party under this Agreement. Except as provided in this section, no action taken pursuant to this Agreement (including without limitation the acts taken at the Closing) shall be deemed to constitute a waiver of compliance with any representations, warranties or covenants contained in

this Agreement and shall not operate or be construed as a waiver of any subsequent breach of a similar or dissimilar nature.

12.6 Entire Agreement. This Agreement (together with the Schedules and Exhibit(s), and that certain Confidentiality Agreement between the Parties dated November 20, 2013, all of which are incorporated herein and made a part hereof by this reference): (i) supersedes any other agreements, whether written or oral, that may have been made or entered into by any of the Parties hereto (or by any director, officer, or representative of such parties) relating to the matter contemplated hereby; and (ii) constitutes the entire agreement by and between the Parties hereto, and there are no representations, warranties, covenants, agreements, or commitments except as expressly set forth herein.

12.7 Amendments. This Agreement may be amended or supplemented at any time only by an additional written agreement executed by the Parties.

12.8 Severability. Any provision of this Agreement which is unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability, without invalidating the remaining provisions hereof, which provisions shall be enforced to the maximum extent permitted by law and construed so as best to effectuate the provisions hereof, and any such prohibition or unenforceability shall not invalidate or render unenforceable such provision in any other jurisdiction.

12.9 Applicable Law. This Agreement and the legal relations among the Parties shall be governed by and construed in accordance with the substantive laws of the State of Utah without giving effect to the principles of conflict of laws thereof.

12.10 Execution and Counterparts. This Agreement may be executed in two or more counterparts, each which shall be deemed an original, but all of which together shall constitute one and the same agreement.

12.11 Titles and Headings. Titles and headings to paragraphs herein are inserted for convenience of reference only and are not intended to be a part of or to affect the meaning or interpretation of this Agreement.

12.12 Third Parties. Except as provided in Article X, nothing herein expressed or implied is intended or shall be construed to confer upon or give any person or entity other than the Parties and their successors and permitted assigns any right or remedies by reason of this Agreement as a third party beneficiary or otherwise.

12.13 Further Assurances. The Parties agree from time to time to execute such additional documents as are necessary to effect the intent of the Parties as manifested by this Agreement.

12.14 JURY WAIVER. TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement by their duly authorized representatives the day and year first above written.

SELLER:

FOSSIL ROCK FUELS, LLC
a Delaware limited liability company

/s/ Cindy A. Crane
Cindy A. Crane
President - Fossil Rock Fuels, LLC

BUYER:

FOSSIL ROCK RESOURCES, LLC
a Delaware limited liability company

/s/ John Siegel
By: John Siegel
Its: Executive Chairman

Exhibit 2.2

OMNIBUS AMENDMENT AGREEMENT

(Fossil Rock Note and Waiver of Conditions)

THIS OMNIBUS AMENDMENT AGREEMENT ("Agreement") is entered into and effective as of June 5, 2015, by and among (i) **FOSSIL ROCK RESOURCES, LLC**, a Delaware limited liability company ("Fossil Rock"), (ii) **HUNTER PREP PLANT, LLC**, a Delaware limited liability company ("HPP"), (iii) **BOWIE COAL SALES, LLC,** a Delaware limited liability company ("BCS"), (iv) **FOSSIL ROCK FUELS, LLC**, a Delaware limited liability company ("FRF"), and (v) **PACIFICORP**, an Oregon corporation ("PCC").

RECITALS:

WHEREAS, PCC and BCS are parties to that certain Coal Supply Agreement dated as of December 12, 2014 (the "Huntington CSA"), pursuant to which BCS has agreed to supply coal to PCC's Huntington Power Plant in Emery County, Utah, as described more fully in the Huntington CSA;

WHEREAS, Fossil Rock and FRF are parties to that certain Asset Purchase and Sale Agreement (Fossil Rock Assets) dated as of December 12, 2014 (the "FR Asset Purchase Agreement"), pursuant to which Fossil Rock has agreed to purchase, and FRF has agreed to sell, the "Purchased Assets" described in the FR Asset Purchase Agreement;

WHEREAS, Fossil Rock and PCC are parties to that certain Asset Purchase and Sale Agreement (Trail Mountain Assets) dated as of December 12, 2014 (the "TM Asset Purchase Agreement"), pursuant to which Fossil Rock has agreed to purchase, and PCC has agreed to sell, the "Purchased Assets" described in the TM Asset Purchase Agreement;

WHEREAS, HPP and PCC are parties to that certain Asset Purchase and Sale Agreement (Preparation Plant Assets) dated as of December 12, 2014, as amended by that certain First Amendment of even date herewith (the "Prep Plant Asset Purchase Agreement"), pursuant to which HPP has agreed to purchase, and PCC has agreed to sell, the "Purchased Assets" described in the Prep Plant Asset Purchase Agreement;

WHEREAS, HPP and PCC are parties to that certain Asset Purchase and Sale Agreement (Central Warehouse Property) dated as of December 12, 2014 (the "CW Asset Purchase Agreement", and together with the FR Asset Purchase Agreement, the Prep Plant Asset Purchase Agreement and the TM Asset Purchase Agreement, collectively, the "Asset Purchase Agreements"), pursuant to which HPP has agreed to purchase, and PCC has agreed to sell, the "Purchased Assets" described in the CW Asset Purchase Agreement; and

WHEREAS, the parties desire to amend certain provisions of the Asset Purchase Agreements and the Huntington CSA, as provided herein.

AGREEMENT:

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which is hereby

acknowledged, the parties hereto agree as follows:

1. DEFINITIONS. Defined terms used but not otherwise defined in this Agreement shall have the meanings ascribed to them in the Asset Purchase Agreements and/or the Huntington CSA, as the case may be.

2. AMENDMENT TO SECTION 2.2 OF THE FR ASSET PURCHASE AGREEMENT. Section 2.2 of the FR Asset Purchase Agreement is hereby amended and restated in its entirety to read as follows:

> "2.2. Purchase Price. As consideration for the sale of the Purchased Assets and the other obligations of Seller hereunder, on the Closing Date, Buyer shall pay to Seller Thirty Million Dollars (USD $30,000,000.00) (the "***Purchase Price***") in the form of a promissory note bearing interest at seven percent (7%) per annum with a maturity date of the earlier of (i) August 31, 2015, or (ii) one (1) business day following the closing of the refinancing of the senior credit facility of Buyer's parent company. The Note shall be substantially in the form attached hereto as Exhibit C ("***Note***") and shall be secured by a parental guarantee from Bowie Resource Holdings, LLC."

3. AMENDMENT TO SECTION 8.2(A) OF THE FR ASSET PURCHASE AGREEMENT. Section 8.2(a) of the FR Asset Purchase Agreement is hereby amended and restated in its entirety to read as follows:

> "(a) Buyer shall execute and deliver the Note in favor of Seller."

4. AMENDMENT TO SECTION 8.3(C) OF THE FR ASSET PURCHASE AGREEMENT. Section 8.3(c) of the FR Asset Purchase Agreement is hereby amended and restated in its entirety to read as follows:

> "(c) Under the terms of the Coal Leases, an advanced minimum royalty payment of One Million Two Hundred Forty Five Thousand Four Hundred Sixty Seven and 37/100 Dollars ($1,245,467.37) was due on or before January 18, 2015. Prior to such date, Seller paid, in full, such royalty payment. At Closing, the Purchase Price will be increased by One Hundred Seventy One Thousand One Hundred Sixty Six and 10/100 Dollars ($171,166.10), to reimburse Seller for said royalty payment, less Six Hundred Thousand Dollars ($600,000), with said reimbursement prorated based on the January 18th due date (the Mineral Lease anniversary date), acknowledging that such minimum royalty is amortized over a period of one (1) year from January 18, 2015. The royalty reimbursement shall be due at Closing, and shall not be included in the Note as set forth in Section 2.2. Except as provided in this Section 8.3(c), Seller waives any rights it may have to seek reimbursement from Buyer with respect to any rentals or royalties paid prior to the Closing.

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5. ADDITION OF EXHIBIT C TO THE FR ASSET PURCHASE AGREEMENT. A new Exhibit C is attached to the FR Asset Purchase Agreement in the form attached as Exhibit A to this Agreement.

6. DEFAULT OF NOTE. In the event the Note delivered by Fossil Rock to FRF under the FR Asset Purchase Agreement is not paid in full by its maturity date, FRF and PCC shall have, in addition to any rights or remedies under the Note, the following options to cure the default under the Note, as determined by FRF and PPC, in their sole discretion:

6.1 Upon demand by FRF and PCC, Fossil Rock and HPP shall sell, assign, transfer and convey to FRF and PCC, respectively, for no consideration and free and clear of all liens created by, through or under Fossil Rock or its affiliates, the Purchased Assets under the FR Asset Purchase Agreement, TM Asset

Purchase Agreement and CW Asset Purchase Agreement, or

6.2 Upon demand by FRF and PCC, FRF and PCC shall have right to recover the Purchase Price under the FR Asset Purchase Agreement, plus accrued interest at the Default Rate as set forth in the Note, through a deduction of Five Dollars ($5.00) per ton from the "Tier 1 Base Price" (as defined under Section 5.02 of Huntington CSA) under the Huntington CSA. FRF and PCC shall have the right to said deduction until such time as the full amount of the Note, and all accrued interest, has been (i) paid by Fossil Rock, or (ii) recovered by FRF and PCC through this deduction from the Tier 1 Base Price.

7. CONDITION OF ASSETS. Prior to full payment of the Note by Fossil Rock, neither Fossil Rock, nor any of its affiliates, shall remove, demolish, sale, materially modify, encumber or adversely change or devalue the Purchased Assets under the FR Asset Purchase Agreement, TM Asset Purchase Agreement or CW Purchase Agreement.

8. WAIVER OF CONDITIONS PRECEDENT.

8.1 California PUC Approvals. Sections 7.1(a) and 7.2(a) of each of the Asset Purchase Agreements provide as conditions precedent to Closing the transactions contemplated under the Asset Purchase Agreements that PCC obtain all regulatory approvals for the transfer of the "Purchased Assets" as defined under and pursuant to the respective Asset Purchase Agreements. Sections 10.01(e) and 10.02(e) of the Huntington CSA provide as conditions precedent to the obligations of BCS and PCC under the Huntington CSA that PCC obtain all necessary regulatory approvals for the execution of the Huntington CSA.

PCC and FRF hereby waive, as to the respective agreements to which they are signatories, the conditions precedent as set forth under Section 7.1(a) of the Asset Purchase Agreements, and Section 10.01(e) of the Huntington CSA, the conditions precedent as they pertain only to any regulatory approvals required from the California Public Utilities Commission. BCS, HPP and Fossil Rock agree to close the transactions contemplated by the Asset Purchase Agreements and Huntington CSA without waiving the conditions precedent under Section 7.2(a) of the Asset Purchase Agreements or Section 10.02(e) of the Huntington CSA as they pertain to any regulatory approvals required from the California Public Utilities Commission, or waiving any rights related thereto.

8.2 Water for Prep Plant. Section 10.01(f) of the Huntington CSA provides as a condition precedent to Closing that HPP shall acquire 200 acre feet of water for use at the Prep Plant. HPP hereby waives this condition precedent.

9. MISCELLANEOUS.

9.1 Binding Effect. This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and permitted assigns.

9.2 Counterparts. This Agreement may be executed in one or more counterparts (including by means of facsimile or e-mail signature pages) and all such counterparts taken together shall constitute one and the same agreement.

9.3 JURY WAIVER. TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS

AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

[*Remainder of Page Intentionally Left Blank; Signatures Follow*]

IN WITNESS WHEREOF, the parties have executed this Agreement as of the date first set forth above.

FOSSIL ROCK RESOURCES, LLC

By: /s/ Johannes H. Dreyer

Name: Johannes H. Dreyer

Title: CEO

HUNTER PREP PLANT, LLC

By: /s/ Johannes H. Dreyer

Name: Johannes H. Dreyer

Title: CEO

BOWIE COAL SALES, LLC

By: /s/ Johannes H. Dreyer

Name: Johannes H. Dreyer

Title: CEO

FOSSIL ROCK FUELS, LLC

By: /s/ Cindy A. Crane

Name: Cindy A. Crane

Title: President

PACIFICORP

By: /s/ Cindy A. Crane

Name: Cindy A. Crane

Title: President/CEO - PacifiCorp dba Rocky Mountain Power

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EXHIBIT A

[attached]

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$30,000,000.00 **June 5, 2015**
Salt Lake City, Utah

PROMISSORY NOTE

FOR VALUE RECEIVED, FOSSIL ROCK RESOURCES, LLC, a Delaware limited liability company ("***Borrower***"), having a mailing address of 6100 Dutchmans Lane, 9th Floor, Louisville, Kentucky 40205, promises to FOSSIL ROCK FUELS, LLC, a Delaware limited liability company ("***Lender***"), as follows:

1. Principal and Interest. Borrower promises to pay to the order of Lender, at 1407 W. North Temple Street, Salt Lake City, Utah 84116, or by wire transfer pursuant to wiring instructions provided by Lender, or at such other place or to such other party as Lender may from time to time designate in writing, in lawful money of the United States of America, the principal sum of Thirty Million Dollars ($30,000,000.00), together with interest thereon from the date hereof until paid in full at a rate equal to seven percent (7.0%) per annum. The entire outstanding principal balance, together with all interest accrued thereon, shall be due and payable in full on or before the earlier of (i) August 31, 2015, or (ii) one (1) business day following the closing of the refinancing of the senior credit facility of Borrower's parent company. Notwithstanding any provision hereof to the contrary, Borrower shall have the right, at any time and from time to time, to prepay, without penalty or liability, all or any portion of the outstanding principal balance of this Promissory Note (the "***Note***").

In the event any payment due hereunder shall not be paid on the date due, such amount shall accrue interest at a rate equal to the lesser of (i) eighteen percent (18.0%) per annum, or (ii) the maximum rate permitted by applicable law (the "***Default Rate***") from the date due until paid and, moreover, in the event any payment shall not be paid within five (5) business days of the date due, then, in addition to any principal and interest then due, a late charge of five percent (5.0%) of such amount shall be due and payable. Further, if upon an Event of Default (as

defined below), Lender elects to accelerate the entire unpaid principal balance, or initiates legal action to collect any monies due hereunder, then the interest rate shall increase from the date of acceleration or initiation of legal action until paid in full, both before and after judgment, to a rate equal to the Default Rate. Interest shall be calculated on the basis of a 360-day year using the actual number of days elapsed divided by 360.

2. Guaranty. As security for Borrower's payment and performance of this Note, concurrently with the execution and delivery of this Note to Lender, Borrower shall cause its affiliate, Bowie Resource Holdings, LLC, a Delaware limited liability company (the "***Guarantor***"), to execute and deliver to Lender a guaranty of Borrower's payment and performance of this Note in the form attached hereto as ***Schedule "A"*** (the "***Guarantee***"). Borrower acknowledges and agrees that the creditworthiness of Guarantor is a basis upon which Lender has determined that it is protected against risk of Borrower's default and thereby has agreed to lend Borrower the principal set forth above. Except with Lender's prior written consent, which consent may be withheld, conditioned or delayed in Lender's sole discretion,

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Borrower agrees that any direct or indirect transfer of more than 49% of the ownership interests of Guarantor shall constitute a breach hereof; provided, however, that Borrower shall not be in violation of this Section 2 so long as any such transfer of ownership interests of Guarantor is to an affiliate of Guarantor with a credit rating equal to or greater than that of Guarantor. Any violation of the above-restriction shall cause the then outstanding principal balance and all interest accrued thereon and any other sums due hereunder, at the option of Lender, to immediately become due and payable

3. Subordination. This Note and the Guarantee shall be subordinated to Guarantor's current senior secured credit facility with Morgan Stanley Senior Funding, Inc. and Deutsche Bank Securities (the "***Senior Credit Facility***").

4. Default. An "Event of Default" shall occur upon the happening of any one of the following events: (a) Borrower fails to pay any amount, principal and interest, within five (5) business days following the date when due; or (b) a breach of any of the terms of (i) this Note, or (ii) that certain Asset Purchase and Sale Agreement (Fossil Rock Assets), dated December 12, 2014, by and between Borrower, as buyer, and Lender, as seller (the "***Asset Purchase Agreement***"); provided that, in the case of a nonmonetary default, any such Event of Default shall not be cured within thirty (30) days (or such other longer period as shall be reasonably necessary therefor (not to exceed, in any event, ninety (90) days), so long as Borrower shall commence to cure any such Event of Default within such thirty (30) day period and thereafter prosecute such cure with reasonable due diligence) following written notice thereof from Lender.

5. Remedies. Upon the occurrence of an Event of Default, in addition to the default provisions contained in that certain Omnibus Amendment Agreement of even date herewith, Lender may declare the entire unpaid principal balance, together with all accrued interest, to be immediately due and payable without presentment, demand or other notice of any kind. To the extent permitted by law, Borrower waives any rights to offset, deduction, protest, presentment, demand, notice of dishonor, or other notice of any kind in connection with this Note, and waives any right to be released by reason of any extension of time or change in terms of payment or any change, alteration, or release of any security given for the payment hereof. No failure or delay on the part of Lender in exercising any right, power, or privilege hereunder shall preclude any other or further exercise thereof or the exercise of any other right, power or privilege provided at law, in equity, or by contract. The rights and remedies provided herein are cumulative and not exclusive of any other rights or remedies. Borrower agrees to pay all costs of collection incurred by reason of the default, including court costs and reasonable attorneys' fees, including such expenses incurred before legal action, during the pendency thereof, and continuing to all such expenses in connection with appeals to higher courts arising out of matters associated herewith.

6. Due on Sale. Borrower acknowledges and agrees that the creditworthiness and expertise of Borrower and its affiliates in owning and operating the property purchased by Borrower under the Asset Purchase Agreement (the "***Property***") is a basis upon which Lender has determined that it is protected against risk of default and thereby has agreed to lend Borrower the principal set forth above. Except with Lender's prior written consent, which consent may be withheld, conditioned or delayed in Lender's sole discretion, Borrower agrees that (a) the Property shall not be sold, agreed to be sold, conveyed, transferred, assigned, disposed of, or encumbered

(except under the Senior Credit Facility), whether voluntarily, involuntarily, by operation of law or otherwise, and/or (b) any direct or indirect transfer of more than 49% of the ownership interests of Borrower shall constitute a breach hereof; provided, however, that Borrower shall not be in violation of this Section 6 so long as any such transfer of the Property or ownership interests of Borrower is to an affiliate of Borrower. Any violation of the above-restrictions shall cause the then outstanding principal balance and all interest accrued thereon and any other sums due hereunder, at the option of Lender, to immediately become due and payable.

7. General Provisions. This Note shall be binding upon Borrower and its successors and assigns. This Note and all documents and instruments associated herewith shall be governed by, and construed and interpreted in accordance with, the laws of the State of Utah. This Note has been delivered to Lender and accepted by Lender in the State of Utah. Venue of any dispute involving this Note or any provision or interpretation thereof, or involving any matter arising out of or connected in any way with this Note, and jurisdiction over the parties hereto, may be in any court of competent jurisdiction in the State of Utah. Borrower hereby irrevocably consents and submits to the jurisdiction and venue of said courts, hereby waiving any rights it may now or hereafter have to object to, or seek a change of, such jurisdiction and venue. The use of paragraph headings in this Note is for convenience only, and Borrower understands and agrees that such headings shall not be used in interpreting or construing this Note or any provision hereof. Time is of the essence hereof and each and every term and provision set forth herein.

8. No Waiver. No single or partial exercise of any power hereunder or under this Note shall preclude other or further exercises thereof or the exercise of any other power. Any delay or omission on the part of Lender in exercising any right hereunder or under this Note shall not operate as a waiver or relinquishment of such right, or of any other right under this Note.

9. Borrower's Representations and Warranties. Borrower acknowledges, represents, warrants and confirms to Lender, and covenants with Lender, as follows:

(a) Borrower is a limited liability company duly organized, validly existing and in good standing pursuant to the laws of the State of Delaware and shall at all times during such time as any obligation remains outstanding under this Note maintain its limited liability company existence and keep current all necessary filings relating thereto;

(b) The execution, delivery and performance by Borrower of this Note have been duly authorized by all necessary member, manager and/or other limited liability company action on the part of Borrower, do not and will not contravene or violate any provision of Borrower's articles of organization or operating agreement, and will not result in the creation or imposition of any lien on Borrower's assets, and the person executing this Note on behalf of Borrower has been duly authorized to do so; and

(c) Borrower will comply in all material respects with the requirements of all laws and regulations applicable to Borrower, the non-compliance of which would be reasonably likely to materially and adversely affect Borrower's business or financial condition.

10. Successors and Assigns. This Note shall inure to the benefit of Lender and its successors and assigns. The obligations of Borrower hereunder shall not be assignable without the prior written consent of Lender, which may be withheld or conditioned in Lender's sole discretion, and any proposed assignment without such consent shall be deemed void.

11. JURY WAIVER. TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS NOTE. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

12. Entire Agreement in Writing. This Note, along with the default provisions contained in that certain Omnibus Amendment Agreement of even date herewith, are the final expressions of the agreement and understanding of Borrower and Lender with respect to the subject matter hereof and supersedes any previous understanding, negotiations or discussions, whether written or oral. This Note may not be contradicted by evidence of any alleged oral agreement.

BORROWER:

FOSSIL ROCK RESOURCES, LLC,
a Delaware limited liability company

By: _____
Print Name: _____
Its: _____

Schedule "A"

To Promissory Note

Form of Guaranty

GUARANTY

The undersigned Bowie Resource Holdings, LLC, a Delaware limited liability company ("***Guarantor***"), hereby guarantees all liabilities and obligations of Fossil Rock Resources, LLC, a Delaware limited liability company ("***Borrower***") under that certain Promissory Note dated June 5, 2015 (the "***Note***"), with Fossil Rock Fuels, LLC, a Delaware limited liability company ("***Lender***"). No failure or delay by Lender in exercising any right or remedy under the Note shall operate as a waiver of such right or remedy. Guarantor hereby waives notice or demand of performance in the acceptance of its obligations under this guarantee. Lender and Borrower may at any time, without notice to or consent of the undersigned, and without in any manner affecting the liability of the undersigned under this guarantee, mutually agree to amend, extend, modify, supplement or waive any term or condition of the Note, and in such event, the undersigned shall be bound by, and this guarantee shall automatically extend to, the Note as so amended, extended, modified, supplemental or waived without any action required by the undersigned. The liability and obligations of the undersigned hereunder shall be primary, direct and absolute and the undersigned hereby waives any right to require that resort be had against any other person.

BOWIE RESOURCE HOLDINGS, LLC,
a Delaware limited liability company

By: _____

Name: _____

Title: _____

Date: _____

Sierra Club Data Request 1.18

Reference the Direct Testimony of Cindy Crane, page 9, lines 17 and 21-22. Is the sale of the Mining Assets to Bowie conditioned on execution and implementation of the Huntington CSA and/or the Hunter CSA? If yes, please describe the condition.

Response to Sierra Club Data Request 1.18

Yes. These transactions are conditioned on obtaining all necessary regulatory approvals by the closing of the Transaction date, including obtaining approval of the Huntington CSA and the Hunter CSA. The transaction is also contingent on the resolution that the UMWA eliminates the successorship obligations at the Preparation Plant and the Trail Mountain Mine.

Sierra Club Data Request 1.23

Are any components of the transaction at issue before the Oregon Commission conditioned upon successful conclusion of the Fossil Rock APA?

Response to Sierra Club Data Request 1.23

The Company objects to this request as not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

The sale of Fossil Rock and its assets are bundled with the execution of the coal supply agreements with Bowie Resources and are included in the transaction. As stated in the Oregon Application, page 9, footnote 8, these assets are not reflected in Oregon rates and would not be at issue before the Oregon Commission.

S-1 1 a2225124zs-1.htm S-1

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As filed with the Securities and Exchange Commission on June 19, 2015

Registration No. 333-

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

BOWIE RESOURCE PARTNERS LP

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**1220**	**47-2966254**
(State or Other Jurisdiction of Incorporation or Organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

6100 Dutchmans Lane, 9th Floor
Louisville, Kentucky 40205
(502) 584-6022
(Address, Including Zip Code, and Telephone Number, Including Area Code, of Registrant's Principal Executive Offices)

Brian S. Settles
General Counsel
6100 Dutchmans Lane, 9th Floor
Louisville, Kentucky 40205
(502) 584-6022
(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent for Service)

Copies to:

Shelley Barber **Brenda Lenahan** **Vinson & Elkins L.L.P.** **666 Fifth Avenue, 26th Floor** **New York, New York 10103** **Tel: (212) 237-0000** **Fax: (212) 237-0100**	**Joshua Davidson** **John Geddes** **Baker Botts L.L.P.** **One Shell Plaza** **910 Louisiana Street** **Houston, Texas 77002** **Tel: (713) 229-1234** **Fax: (713) 229-1522**

Approximate date of commencement of proposed sale to the public:
As soon as practicable after this Registration Statement becomes effective.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933 (the "Securities Act"), check the following box. o

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer o	Non-accelerated filer ý (Do not check if a smaller reporting company)	Smaller reporting company o

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Proposed Maximum Aggregate Offering Price(1)(2)	Amount of Registration Fee
Common units representing limited partner interests	$100,000,000	$11,620

(1) Includes common units issuable upon exercise of the underwriters' option to purchase additional common units.

(2) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(o).

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act or until the registration statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

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The information in this preliminary prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission becomes effective. This preliminary prospectus is not an offer to sell these securities, and we are not soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

SUBJECT TO COMPLETION, DATED , 2015

PROSPECTUS

BOWIE RESOURCE PARTNERS LP

Common Units
Representing Limited Partner Interests

This is the initial public offering of our common units representing limited partner interests. Prior to this offering, there has been no public market for our common units. We are offering common units in this offering. We currently expect the initial public offering price to be between $ and $ per common unit. We intend to apply to list our common units on the New York Stock Exchange under the symbol "BRLP."

The underwriters have the option to purchase up to additional common units from us at the initial public offering price, less the underwriting discounts, within 30 days from the date of this prospectus to cover over-allotments, if any.

Investing in our common units involves risks. Please read "Risk Factors" beginning on page 22.

These risks include the following:

- We may not have sufficient cash from operations to pay the minimum quarterly distribution on our common and subordinated units following establishment of cash reserves and payment of costs and expenses, including reimbursement of expenses to our general partner. On a pro forma basis, we would not have had sufficient cash available for distribution to pay the full minimum quarterly distribution on all of our units for the year ended December 31, 2014 or the twelve months ended March 31, 2015.
- A substantial or extended decline in coal prices or increase in the costs of mining or transporting coal could have a material adverse effect on our results of operations and our ability to pay distributions to our unitholders.
- Competition within the coal industry may adversely affect our ability to sell coal, and excess production capacity in the industry could put downward pressure on coal prices.
- Our mining operations, including our transportation infrastructure, are extensively regulated, which imposes significant costs on us, and changes to existing and potential future regulations or violations of regulations could increase those costs or limit our ability to produce and sell coal.
- Our level of indebtedness and the terms of our borrowings could adversely affect our ability to grow our business, our ability to make cash distributions to our unitholders and our credit ratings and profile.
- Our general partner and its affiliates, including our sponsor, have conflicts of interest with us and limited duties, and they may favor their own interests to the detriment of us and our unitholders.
- All of our revenue and cash flow will be derived from our coal supply agreements, and we will receive substantially all of our revenue and cash flow from our new coal supply agreement with our sponsor. Therefore, we will be subject to the business risks of our sponsor.
- Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which our common units will trade.
- Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without its consent.
- Unitholders who are not "Eligible Holders" will not be entitled to receive distributions on or allocations of income or loss on their common units, and their common units will be subject to redemption.
- If the Internal Revenue Service were to treat us as a corporation for federal income tax purposes or we were to become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to our unitholders would be substantially reduced.
- Our unitholders will be required to pay taxes on their share of our taxable income even if they do not receive any cash distributions from us.

In addition, we qualify as an "emerging growth company" as defined in the Jumpstart Our Business Startups Act of 2012, and as such, are allowed to provide in this prospectus more limited disclosures than an issuer that would not so qualify. Furthermore, for so long as we remain an emerging growth company, we will qualify for certain limited exceptions from investor protection laws such as the Sarbanes-Oxley Act of 2002 and the Investor Protection and Securities Reform Act of 2010. Please read "Prospectus Summary—Our Emerging Growth Company Status."

In order to comply with certain U.S. laws relating to the ownership of interests in mineral leases on federal lands, we require an owner of our common units to be an "Eligible Holder." If you are not an Eligible Holder, you will not be entitled to receive distributions on or allocations of income or loss on your common units and your common units will be subject to redemption.

	Per Common Unit	Total
Public Offering Price	$	$
Underwriting Discount	$	$
Proceeds to Bowie Resource Partners LP (before expenses)	$	$

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the common units to purchasers on or about , 2015.

Joint Book-Running Managers

Citigroup **Morgan Stanley** **Deutsche Bank Securities**
UBS Investment Bank **Credit Suisse** **Stifel**

Co-Managers

Brean Capital

, 2015

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APPENDIX B GLOSSARY OF DEFINED TERMS B-1

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You should rely only on the information contained in this prospectus. We have not authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We and the underwriters take no responsibility for, and can provide no assurance as to the reliability of, any other information that others may give you. We are not, and the underwriters are not, making an offer to sell these securities in any jurisdiction where the offer or sale is not permitted. You should not assume that the information contained in this prospectus is accurate as of any date other than the date on the front of this prospectus.

Coal Reserve Information

"Reserves" are defined by the SEC Industry Guide 7 as that part of a mineral deposit that could be economically and legally recovered or produced at the time of the reserve determination. Industry Guide 7 divides reserves between "proven (measured) reserves" and "probable (indicated) reserves" which are defined as follows:

- "Proven (measured) reserves." Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

- "Probable (indicated) reserves." Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling, and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

Our coal reserve estimates include both assigned and unassigned reserves.

Our coal reserve estimates include reserves that can be economically and legally recovered or produced at the time of their determination. In determining whether our reserves meet this standard, we take into account, among other things, the possible necessity of revising a mining plan, changes in estimated future costs, changes in future cash flows caused by changes in costs required to be incurred to meet regulatory requirements and obtain mining permits, variations in quantity and quality of coal, and varying levels of demand and their effects on selling prices. Further, the economics of our reserves are based on market conditions, including contracted pricing, market pricing and overall demand for our coal. Thus, the actual value at which we no longer consider our reserves to be economic varies depending on the length of time in which the specific market conditions are expected to last. We consider our reserves to be economic at a price in excess of our cash costs to mine the coal and our ongoing replacement capital. Because we do not regularly wash our coal, our reserve estimates do not include potential losses from the washing process.

The information appearing in this prospectus concerning estimates of our proven and probable coal reserves (including the proven and probable coal reserves for Fossil Rock and the Flat Canyon tract, each as defined in this prospectus) was prepared by Norwest Corporation ("Norwest") as of December 31, 2014. Unless otherwise noted, all estimates regarding our proven and probable coal reserves discussed in this prospectus are based on the reserve report prepared by Norwest as of December 31, 2014. Statements of non-reserve coal deposits for the Greens Hollow tract (as defined in this prospectus) rely solely on the estimates of management and have not been prepared or audited by Norwest. All Btus per pound are expressed on an as-received basis, including total moisture. Please read "Business—Coal Reserves and Non-Reserve Coal Deposits."

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Market and Industry Data and Forecasts

In this prospectus, we rely on and refer to information regarding the coal industry, future coal production and consumption and future electricity generation in the United States and internationally from the U.S. Energy Information Administration ("EIA"), World Coal Association, U.S. Mine Safety and Health Administration ("MSHA"), National Mining Association, BP Statistical Review, Baker Hughes, Argus Media, globalCOAL and Wood Mackenzie, none of which are affiliated with us. We have commissioned Wood Mackenzie to provide certain market and industry data and forecasts contained in this prospectus.

When we make statements in this prospectus about our position in our industry or any sector of our industry or about our market share, we are making statements of our belief. This belief is based on data from various sources (including government data, industry publications, surveys and forecasts), on estimates and assumptions that we have made based on that data and other sources and our knowledge of the markets for our products.

We do not have any knowledge that the market and industry data and forecasts provided to us from third-party sources are inaccurate in any material respect. However, we have been advised that certain information provided to us from third-party sources is derived from estimates or subjective judgments, and while such third-party sources have assured us that they have taken reasonable care in the compilation of such information and believe it to be accurate and correct, data compilation is subject to limited audit and validation procedures. We believe that, notwithstanding such qualification by such third-party sources, the market and industry data provided in this prospectus is accurate in all material respects.

Our estimates, in particular as they relate to market share and our general expectations, involve risks and uncertainties and are subject to change based on various factors, including those discussed under the section entitled "Risk Factors."

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PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. This summary does not contain all of the information you should consider before investing in our common units. You should read the entire prospectus carefully, including the section describing the risks of investing in our common units under "Risk Factors" and the financial statements contained elsewhere in this prospectus before making an investment decision. Some of the statements in this summary constitute forward-looking statements. Please read "Forward-Looking Statements." The information presente in this prospectus assumes an initial public offering price of $ per common unit (the mid-point of the price range set forth on the cover page o this prospectus) and, unless otherwise indicated, that the underwriters' option to purchase additional common units to cover over-allotments is not exercised.

References in this prospectus to the "partnership," "we," "our," "us" or like terms when used in a historical context refer to the business of Canyon Fuel Company, LLC and its subsidiaries, which will be our wholly-owned subsidiaries following this offering, or Bowie Resource Partners LP and its subsidiaries thereafter, as the context requires. When used in the present tense or prospectively, "the partnership," "we," "our," "us" or like terms refer to Bowie Resource Partners LP and its subsidiaries and "our operating company" refers to BRP Holdings LLC, a wholly-owned subsidiary of ours, in each case after giving effect to the transactions described in "—IPO Reorganization and Partnership Structure." Except where expressly noted, references in this prospectus to "our sponsor" refer to Bowie Resource Partners, LLC, together with its wholly-owned subsidiaries, including Bowie Resource Holdings, LLC, but excluding the partnership. References in this prospectus to "our general partner" refer to Bowie GP, LLC, a wholly-owned subsidiary of our sponsor, and references to "our executive officers" and "our directors" refer to the executive officers and directors of our general partner. Our coal sales were historically made under coal supply agreements between our sponsor and our end customers. In connection with the closing of this offering, we expect to enter into a coal supply agreement with our sponsor, pursuant to which it will purchase substantially all of our coal on substantially the same terms as our sponsor's agreements with our end customers. References in this prospectus to "our coal supply agreements" refer to (i) coal supply agreements between us and our customers, (ii) coal supply agreements between us and our sponsor and (iii) coal supply agreements between our sponsor and the end customers of our coal. References in this prospectus to "our customers" refer to customers purchasing coal directly from us and customers purchasing our coal through our sponsor. For the definitions of certai other terms used in this prospectus, please read "Appendix B: Glossary of Defined Terms."

Bowie Resource Partners LP

Overview

We were recently formed by our sponsor as a growth-oriented master limited partnership focused on:

- operating safe, low-cost, strategically-located underground coal mines that produce high quality (high Btu, low sulfur) thermal coal;
- providing the lowest delivered cost fuel option (coal or natural gas) to our key regional customers, capitalizing on our high productivity, high quality coal and geographic proximity to these customers;
- fulfilling and extending our long-term, high-volume, fixed-price coal supply agreements;
- growing our cash flows through prudent acquisitions of strategically-positioned assets; and
- capitalizing on our differentiated transportation and logistics network that positions us as the only U.S. coal producer with contracted U.S. West Coast export capacity.

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We operate three underground coal mines in Utah with a productive capacity of approximately 12.6 million tons per year: (i) the Sufco mine, near Salina, Utah, which is a longwall operation with a productive capacity of approximately 7.0 million tons per year, (ii) the Skyline mine, near Scofield, Utah, which is a longwall operation with a productive capacity of approximately 4.5 million tons per year, and (iii) the Dugout Canyon mine, near Price, Utah, which has been a longwall operation but is currently a multi-continuous miner operation with a productive capacity of approximately 1.1 million tons per year. Our mines are located in the Uinta Basin in Utah within the Western Bituminous region where a significant percentage of the coal qualifies as "compliance coal" under the Clean Air Act. Our operations were among the most productive underground coal mines in the United States for the year ended December 31, 2014 on a clean tons produced per man hour basis based on MSHA data and, according t Wood Mackenzie, we are one of the largest producers of low-cost, high margin thermal coal in the Western Bituminous region.

The high productivity of our strategically-located mines, together with our sponsor's transportation and logistics network, enables us to deliver our coal to our key regional customers at a lower cost per Btu compared to coal from other producers in the Western Bituminous region, coal from other basins and natural gas, even when adjusted for different heat rate efficiencies between coal and natural gas-fired power plants.

The majority of our coal sales for the year ended December 31, 2014 and the three months ended March 31, 2015 were made to domestic customers pursuant to long-term, high-volume coal supply agreements with fixed pricing, subject to certain price escalators and adjustments. On a pr forma basis, after giving effect to the closing of the Utah Transaction, we expect coal sales under our existing coal supply agreements for each of the next four years to surpass 80% of our production for the twelve months ended March 31, 2015, which should provide significant sustainable revenue and allow us to generate stable and reliable cash flows. Please read "—Recent Developments" for a description of the Utah Transaction and "Busines —Customers—Coal Supply Agreements with Key Customers."

As part of our domestic sales portfolio, we have multi-year coal supply agreements with PacifiCorp and Intermountain Power Agency ("IPA"), two investment-grade regional utilities that operate power plants located in close proximity to our mines. These plants were designed to burn high Btu, low sulfur Utah coal. Our coal supply agreements with PacifiCorp and IPA provide for aggregate sales of (i) a minimum of 7.0 million tons and maximum of 10.5 million tons per year through December 31, 2020, (ii) a minimum of 4.5 million tons and a maximum of 6.0 million tons per year through December 31, 2024 and (iii) a minimum of 2.0 million tons and a maximum of 3.0 million tons per year through December 31, 2029. We believe that our contracts with PacifiCorp and IPA that are set to expire in 2020 and 2024 have the potential to be extended in the future, should we choose to do so. All of our coal supply agreements with PacifiCorp and IPA include price escalators, as well as provisions that allow us to pass through (by means of a price increase) certain increases in mining and transportation costs. Please read "Business—Customers."

We have significantly enhanced the performance of our mines since they were acquired by our sponsor in August 2013. Coal production at our mines increased from 9.7 million tons for the year ended December 31, 2013 to 11.4 million tons for the year ended December 31, 2014. During the year ended December 31, 2014, we realized net loss, operating income and Adjusted EBITDA of $4.9 million, $31.4 million and $125.3 million, respectively, as compared to net income, operating income and Adjusted EBITDA of $8.1 million, $22.1 million and $75.5 million, respectively, for the year ended December 31, 2013. Please read "—Summary Historical and Pro Forma Financial and Other Data—Non-GAAP Financial Measures" for the definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our most directly comparable financial measure calculated and presented in accordance with GAAP.

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We plan to seek acquisition targets similar to our current operations, utilizing our sales contract position, our strategic export capacity and our proven ability to maximize productivity in order to facilitate future accretive transactions. Pursuant to the omnibus agreement that we expect to enter into in connection with this offering, our sponsor will grant us a right of first refusal with respect to certain coal and terminal properties. In addition, we expect to enter into an agreement with Bowie Refined Coal, LLC, an affiliate of our sponsor, providing us with a right of first refusal to acquire certain refined coal projects that it owns. Please read "Certain Relationships and Related Party Transactions." Additionally, we will pursue three organic development projects in the next decade; specifically, the addition of a third continuous miner to our Dugout Canyon mine, the development of the Fossil Rock reserves and the development of reserves in the Lower Hiawatha seam of our Sufco mine. Finally, we expect to benefit from increasing demand and prices for our coal in the export markets of the Pacific Rim. Please read "—Recent Developments" for a description of the Fossil Rock reserves.

We benefit from a differentiated transportation and logistics network established by our sponsor, including its access to port terminals in California through which we export our coal to a variety of growing economies on the Pacific Rim. According to Wood Mackenzie, overall demand for thermal coal imports into the Pacific market is expected to increase from 757 million metric tons in 2014 to 910 million metric tons in 2020 and 1.3 billion metric tons in 2030. Through our sponsor, we are the only coal producer with contracted U.S. West Coast export capacity, with access to terminals with an aggregate throughput capacity of approximately 5.7 million tons per year. For the year ended December 31, 2014, our sponsor exported approximately 3.3 million tons through these terminals, and we expect our sponsor to export approximately 1.0 million tons through these terminals for the year ending December 31, 2015. Prior to our sponsor leasing these terminals, no significant amount of thermal coal had been shippe through these terminals for over 10 years.

Trafigura AG ("Trafigura AG") is the exclusive marketer of our uncommitted coal, and its parent company, Trafigura Beheer B.V. ("Trafigura BV"), indirectly owns a minority interest in our sponsor. Trafigura AG and its affiliates directly or indirectly market approximately 50 million tons of coal per year in the international market. By leveraging Trafigura AG's and its affiliates' significant expertise in the coal export market and existing commodities trading infrastructure, we are able to sell our coal internationally to a variety of intermediary and end users in the power generation business.

Business Strategies

Our principal business objective is to consistently generate stable cash flows that enable us to pay quarterly cash distributions to our unitholders and, over time, sustainably increase our quarterly distributions. We expect to achieve this objective through the following business strategies:

- ***Maintaining industry-leading safety standards.*** Safety is a top priority for us, and we incorporate and emphasize safety in all aspects of our operations, including mine operations and processes and equipment selection. Our mines have been industry leaders in the United States, with each having completed at least one calendar year without an MSHA recordable injury and each having received th National Mining Association's prestigious Sentinel of Safety award. We plan to continue working with equipment manufacturers in ar effort to ensure our mining equipment and processes remain safe, and to continue implementing safety measures to maintain the high quality of our underground infrastructure.

- ***Growing production and operating cash flows.*** We expect our coal production and cash flows to increase as a result of the Utah Transaction, and we have a pipeline of potential organic development projects to further develop our reserve base with minimal additional surface infrastructure required. Additionally, we expect to pursue acquisitions from our sponsor through its portfolio of assets and contractual rights, as well as third-party opportunities for which we are uniquely positioned. Pursuant to the omnibus agreement that we expect to enter into in

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connection with this offering, our sponsor will grant us a right of first refusal with respect to certain coal and terminal properties. In addition, we expect to enter into an agreement with Bowie Refined Coal, LLC, an affiliate of our sponsor, providing us with a right of first refusal to acquire certain refined coal projects that it owns. Please read "Certain Relationships and Related Party Transactions."

- ***Further strengthening our established relationships with our customers.*** We are continuously evaluating opportunities to further strengthen our commercial relationships with our long-term customers. For example, in connection with the Utah Transaction, our sponsor entered into a new 15-year coal supply agreement with PacifiCorp, one of our principal customers, providing for additional sales to PacifiCorp of a minimum 2.0 million tons and a maximum of 3.0 million tons of coal per year through 2029. Please read "Business—Customers."

- ***Maintaining our delivered cost advantage with our key regional customers.*** Our mines have a track record of stable production and low direct mining costs per ton. For the year ended December 31, 2014 and the three months ended March 31, 2015, our operations had direct mining costs per ton of $20.31 and $22.90, respectively. Direct mining costs per ton is defined as cost of coal sales, exclusive of items shown separately (as defined in Appendix B), divided by tons sold. We intend to continue building upon and expanding our position as one of the lowest cost Western Bituminous coal producers. Low operating costs, driven by high-quality longwall reserves, a skilled and experienced non-union workforce and a consistent safety track record, combined with our geographical advantage and cost competitive transportation contracts, should allow us to maintain our overall competitive advantage on a delivered cost basis and continue to drive favorable margins in nearly any coal price environment, further differentiating us from our peers.

- ***Utilizing our sponsor's export capacity to expand the size and diversity of our coal sales portfolio.*** While we view sales to local utility customers as our principal generator of cash flows, we expect to benefit from our sponsor's plan to further expand sales into international coal markets, which we expect to provide additional cash flows and diversification from our primary domestic market. We expect export coal markets to have the potential to provide significant growth opportunities relative to the domestic coal market. Although the largest domestic coal producers have attempted to secure export capacity to access the Pacific market, we are the only coal producer with contracted U.S. West Coast export capacity. This provides us with unique competitive advantages, including the option of selling any uncommitted coal we produce into international markets.

- ***Continuing to develop and grow our reserve base.*** We believe our Dugout Canyon mine can support an additional continuous miner unit without any additional surface infrastructure, which would increase its productive capacity from approximately 1.1 million tons per year to approximately 1.5 million tons per year. The Fossil Rock reserves increase our proven and probable reserves by an estimated 11.2 million tons and 32.5 million tons, respectively, and at full production, we expect to produce approximately 4.0 million tons of coal per year from the Fossil Rock reserves from 2017 through 2034. Additionally, we expect to obtain a lease from the BLM through the lease by application process for the Greens Hollow tract, which contains approximately 50.5 million tons of non-reserve coal deposits, including those in the Lower Hiawatha seam, accessible through our Sufco mine.

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Competitive Strengths

We believe we are well-positioned to execute our business strategies because of the following competitive strengths:

- ***Portfolio of multi-year, fixed-price coal supply agreements providing stable long-term cash flows.*** We believe our long-term coal supply agreements provide significant sustainable revenue and should generate stable and reliable cash flows. On a pro forma basis, after giving effect to the closing of the Utah Transaction, we expect coal sales under our existing coal supply agreements of approximately 11.2 million tons in 2015, 9.0 million tons in 2016, 9.5 million tons in 2017 and 9.3 million tons in 2018, which represent approximately 100%, 82%, 86% and 84%, respectively, of our production for the twelve months ended March 31, 2015. Included in our sales portfolio are our coal supply agreements with PacifiCorp and IPA providing for aggregate sales of (i) a minimun of 7.0 million tons and a maximum of 10.5 million tons per year through December 31, 2020, (ii) a minimum of 4.5 million tons and a maximum of 6.0 million tons per year through December 31, 2024 and (iii) a minimum of 2.0 million tons and a maximum of 3.0 million tons per year through December 31, 2029, all of which have fixed pricing, subject to certain price escalators and adjustments as described in further detail under "Business—Customers."

- ***Lowest delivered cost to key regional customers maintained by geographic advantage and productivity.*** Our mines are strategically located in close proximity to our principal customers, and we have in place cost competitive options for both trucking and rail transportation of our coal to these customers. According to Wood Mackenzie, we can deliver our coal to PacifiCorp and IPA at a lowe cost per Btu compared to coal from other producers in the Western Bituminous region, coal from other basins and natural gas, even when adjusted for different heat rate efficiencies between coal and natural gas-fired power plants. Our two longwall mines were among the 15 most productive underground coal mines in the United States for the year ended December 31, 2014, on a clean tons produced per man hour basis based on MSHA data. Our industry-leading productivity and resulting low direct mining costs per ton ar driven by favorable geology and a highly motivated and skilled non-union workforce.

- ***Strategically positioned to take advantage of synergistic and value-added acquisition opportunities in the Western Bituminous region.*** We are the largest producer of coal in the Uinta Basin, producing 84% more coal than the next largest Western Bituminous coal producer in the Uinta Basin in 2014, according to MSHA production data. In executing our acquisition strategy, we plan to seek acquisition targets similar to our current operations, utilizing our sales contract position, our strategic export capacity and our proven ability to maximize productivity in order to facilitate future accretive transactions. Retaining the largest footprint in the Uinta Basin provides us with a strong foundation for growth within both the Uinta Basin and the broader Western Bituminous region. Our contracted position and ability to sell coal into the international market should allow us to evaluate acquisition opportunities with potential for value creation by expanding production at operations that would otherwise be market constrained.

- ***Differentiated transportation and logistics network providing profitable access to growing markets for our coal on the Pacific Rim.*** We are the only coal producer with contracted U.S. West Coast export capacity. According to Wood Mackenzie, overall demanc for thermal coal imports into the Pacific market is expected to increase from 757 million metric tons in 2014 to 910 million metric tor in 2020 and 1.3 billion metric tons in 2030. We have access to export terminals in California with an aggregate throughput capacity of approximately 5.7 million tons per year. Our cost structure and the location of our mines allow us to profitably export coal when the applicable seaborne thermal benchmark price prevents our competitors from doing so. Our export capacity is enhanced by market reach through our relationship with Trafigura AG, one of

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the largest global commodity trading houses. Trafigura AG is the exclusive marketer of our uncommitted coal and its parent company Trafigura BV, indirectly owns a minority interest in our sponsor. Trafigura AG and its affiliates directly or indirectly market approximately 50 million tons of coal per year in the international market.

- ***Proven management capabilities and industry leading safety standards.*** Our mine management team is comprised of long-tenured coal mining professionals, highly skilled in the planning and execution of Western Bituminous coal mining operations. Our senior operations personnel have, on average, more than 30 years of experience in the coal industry. They are hands-on operators with substantial experience in operating safe mines, increasing productivity and reducing costs. In addition, our senior executives have a proven track-record of successfully identifying, acquiring, financing and integrating assets that enhance the value of our business. Our operations have exemplary safety records, and we strongly believe that safety is the most important factor in productivity. Safety is a focus and value in all aspects of our business. According to MSHA data, we have consistently outperformed national average rates in historical safety violations as well as lost-time safety incident rates.

Recent Developments

Utah Transaction

On June 5, 2015, we acquired certain undeveloped, high Btu, low sulfur coal reserves in Utah (the "Fossil Rock reserves") from an affiliate of PacifiCorp (the "Utah Transaction"). As part of the Utah Transaction, our sponsor entered into an agreement with PacifiCorp to supply all of the coal requirements of PacifiCorp's Huntington Power Plant in Utah through 2029. The Fossil Rock reserves increase our proven and probable reserves by an estimated 11.2 million tons and 32.5 million tons, respectively. At full production, we expect to produce approximately 4.0 million tons of coal per year from the Fossil Rock reserves from 2017 through 2034. The Fossil Rock reserves are located closer to PacifiCorp's Huntington and Hunter Power Plants than our existing mines, which we believe will significantly reduce our transportation costs to this principal customer.

Flat Canyon Lease

On June 17, 2015, we were notified by the BLM, as part of the lease by application process, that we submitted the only bid in the competitive lease sale of the Flat Canyon tract held on June 17, 2015. On June 19, 2015, we were notified by the BLM, as part of the lease by application process that our bid met or exceeded the BLM's estimate of the fair market value of the tract, which contains approximately 14.2 million tons and 15.2 million tons of proven and probable reserves, respectively. The issuance by the BLM of the lease of the Flat Canyon tract remains subject to a 30-day antitrust review of the U.S. Department of Justice. The leasing action could also be challenged in the Department of Interior's Board of Land Appeals or in federal district court. The May 15, 2015 Notice of Lease Sale of the Flat Canyon tract prompted letters by several non-governmental organizations objecting to the lease sale on, among other things, environmental grounds. Please read "Business—Coal Reserves and Non-Reserve Coal Deposits—Reserve Acquisition Process."

Senior Secured Notes Offering and Revolving Credit Facility

Prior to this offering Bowie Finance Corp. ("Finance Corp."), our wholly owned subsidiary, closed a private placement of $ million aggregate principal amount of % senior secured notes due (the "New Notes"). In connection with the closing of the offering of New Notes, Finance Corp. deposited into an escrow account the gross proceeds from the New Notes offering, plus an amount sufficient to pay certain accrued interest and accreted yield. The release of the escrowed funds will be subject to the satisfaction of certain conditions, including the consummation of this offering (the

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"Escrow Release Conditions"). From and after the satisfaction of the Escrow Release Conditions, which we expect to occur concurrently with the closing of this offering, the partnership will become a co-issuer of the New Notes and a party to the indenture governing the New Notes, and will receive $ million of net proceeds (after payment of underwriting discounts) from the offering of the New Notes. The New Notes will be guaranteed on a senior secured basis, jointly and severally, by all of the partnership's direct and indirect wholly owned domestic subsidiaries that will guarantee our indebtedness under a new $ million revolving credit facility that we expect to enter into concurrently with the closing of this offering. This prospectus is not an offer to sell any of the New Notes.

Coal Market Overview

Domestic demand for Western Bituminous coal is growing. According to Wood Mackenzie, coal production from the Western Bituminous region increased between 2013 and 2014, despite lower sales to traditional buyers of Colorado coal such as the Tennessee Valley Authority. There ha been growth in the Utah coal market, a subregion of the Western Bituminous region, which is insular in nature due to its low delivered cost, its high Btu value and its low sulfur content. In 2014, coal production in Utah increased by 9% over 2013 levels, according to MSHA data. Coal produced in Utah is an ideal base load fuel source for the regional power plants, including those that do not have scrubbers. Over the last few years, largely as a result of our sponsor's activities, increasing amounts of Western Bituminous coal have been exported through terminals on the U.S. West Coast. Woo Mackenzie projects production of Utah coal to grow to 20.7 million tons in 2020, representing a compound annual growth rate of 3.4% from 2013 production.

Coal remains an in-demand, cost-competitive energy source in the United States. Coal has historically been a low-cost, stable and reliable source of energy relative to alternative fuel sources. Conventional coal-powered generation plants also have a lower level of capital cost relative to alternative energy sources, such as nuclear, hydroelectric, wind and solar power. Despite recent reductions in coal-fired electrical demand, coal is expected to continue to account for the largest share of the electricity generation mix in the United States, representing an average 41.0% share of domestic electricity generation from 2014 to 2020 according to the EIA. According to Wood Mackenzie, total U.S. electricity generation is expected to grow by a total of 20.3% from 2014 to 2025.

Global coal demand continues to grow. According to the World Coal Association, in 2013, coal serviced 30.1% of global primary energy needs (the highest since 1970) and generated over 40% of the world's electricity. The World Coal Association estimates that total world coal production reached a record level of 7.8 billion metric tons in 2013, or 0.4% more than in 2012. The World Coal Association reports that coal has accounted for nearly half of the increase in global energy use over the past decade, with coal's global contribution in the 21st century alone being comparable to the contribution of nuclear, oil, natural gas and renewables combined. In 2013, global coal consumption grew by 2.8% compared to 2012, making coal the world's fastest growing fossil fuel during the period.

Long-term growth in demand for seaborne thermal coal supply focused in the Pacific Rim. Although prices for seaborne thermal coal declined in 2014, we believe that over the long-term, Pacific Rim demand for global seaborne thermal coal will increase. According to Wood Mackenzie, the industrialization and development of China, India and the wider Asia Pacific region should support the long-term future of coal in the global energy mix, with China accounting for 39% of global thermal coal demand growth between 2014 and 2030. By 2030, Chinese thermal coal demand is expected to represent 47% of world thermal coal demand according to Wood Mackenzie. The graph below illustrates this increase in demand for coal in Asia. Wood Mackenzie projects that Pacific market thermal coal demand will increase at a compound annual growth rate of 3.6% through 2035. Western Bituminous coal is well situated to take advantage of this growing Asian seaborne demand with Utah

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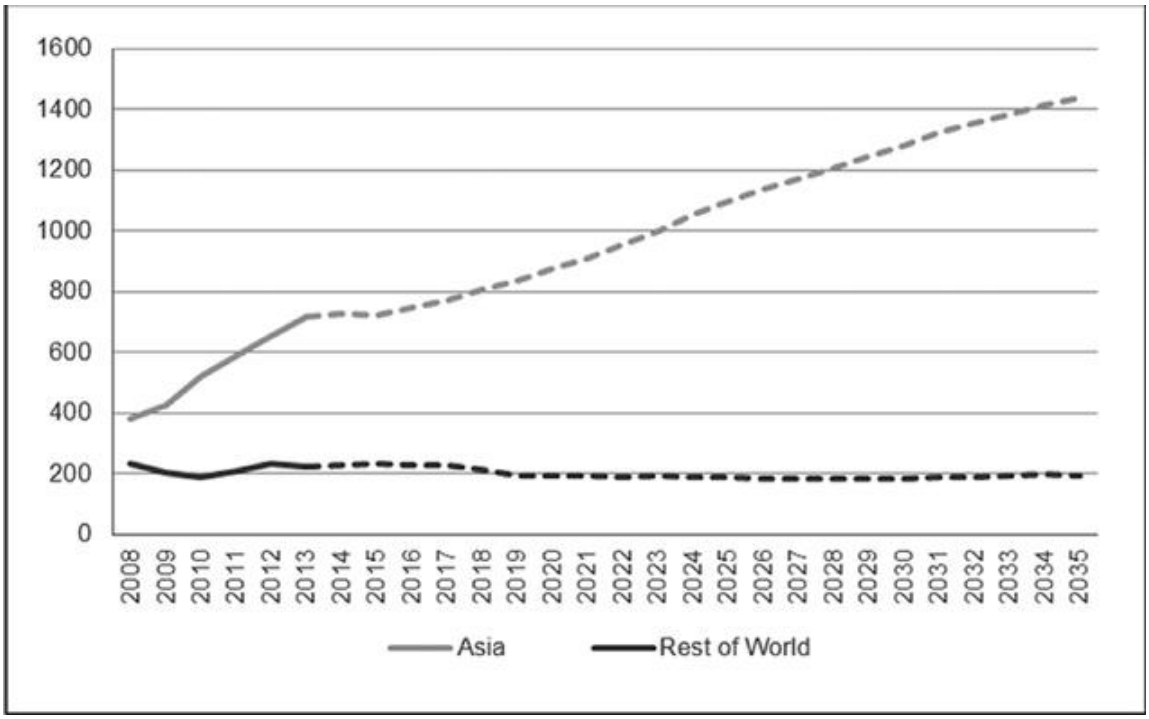
coal being the lowest cost bituminous U.S. coal supplied into an ocean vessel FOB on the U.S. West Coast.

Thermal Seaborne Import Coal Demand

Million Metric Tons



Source: Wood Mackenzie, May 2015

Sponsor

One of our principal strengths is our relationship with our sponsor. Our sponsor is owned by Cedars Energy, LLC ("Cedars") and Galena US Holdings, Inc. ("Galena"). Cedars is a coal sector investor with a track record of acquiring, integrating and developing coal and coal-related assets. Galena is wholly owned by Galena Private Equity Resource Fund, which is managed by Galena Asset Management S.A. ("Galena Asset Management"), a wholly-owned subsidiary of Trafigura BV. Trafigura AG, a wholly-owned subsidiary of Trafigura BV, is our exclusive marketing agent. Trafigura BV has 45 offices in 36 countries around the world and generated revenues of approximately $127.6 billion in 2014. By leveraging Trafigura AG's and its affiliates' significant expertise in the coal export market and existing commodities trading infrastructure, we are able to sell ou coal internationally to a variety of intermediary and end users in the power generation business. Our sponsor has extensive experience in identifying, acquiring, financing and integrating assets that enhance the value of our business. Our sponsor successfully executed a business plan that increased the post-acquisition profitability of our operations, resulting in a 66% increase in Adjusted EBITDA from the year ended December 31, 2013 to the year ended December 31, 2014. We believe that our sponsor's experience and expertise in mergers and acquisitions of strategic assets will enhance ou ability to achieve our growth objectives. Please read "Business—Our Sponsor."

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Risk Factors

An investment in our common units involves risks. Please read carefully the risks described under the caption "Risk Factors" beginning on page 21 of this prospectus.

Management

We are managed and operated by the board of directors and executive officers of our general partner, Bowie GP, LLC, a wholly-owned subsidiary of our sponsor. Some of our directors and all of our executive officers also serve as directors and executive officers of our sponsor. Following this offering, % of our outstanding common units and all of our outstanding subordinated units and incentive distribution rights will b owned, directly or indirectly, by our sponsor. As a result of controlling our general partner, our sponsor will have the right to appoint all members of the board of directors of our general partner, including the independent directors. Our unitholders will not be entitled to elect our general partner or it directors or otherwise directly participate in our management or operations. Certain executive officers of our general partner hold a profits interest in our sponsor. For more information about the executive officers and directors of our general partner, please read "Management."

Following the consummation of this offering, neither our general partner nor our sponsor will receive any management fee, but we will reimburse our general partner and its affiliates for all expenses they incur and payments they make on our behalf. Our partnership agreement provide that our general partner will determine the expenses that are allocable to us. In addition, pursuant to an omnibus agreement, we will reimburse our sponsor on a cost-of-services basis for certain services performed on our behalf. Please read "Certain Relationships and Related Party Transactions."

Our operations will be conducted through, and our operating assets will be owned by, our operating company, BRP Holdings LLC. All of the employees that conduct our business will be employed by our general partner, its affiliates or our subsidiaries.

Conflicts of Interest and Fiduciary Duties

Our general partner has a contractual duty to manage us in a manner that it believes is not adverse to our interest. However, the officers and directors of our general partner also have duties to manage our general partner in a manner beneficial to our sponsor, the owner of our general partne Our sponsor and its affiliates are not prohibited from engaging in other business activities, including those that might be in direct competition with us In addition, our sponsor may compete with us for investment opportunities and may own an interest in entities that compete with us. As a result, conflicts of interest may arise in the future between us or our unitholders, on the one hand, and our sponsor and our general partner, on the other hanc

Our partnership agreement limits the liability of and replaces the fiduciary duties that would otherwise be owed by our general partner to our unitholders. Our partnership agreement also restricts the remedies available to our unitholders for actions that might otherwise constitute a breach of duties by our general partner or its directors or officers. Our partnership agreement also provides that affiliates of our general partner, including our sponsor, are not restricted from competing with us and have no obligation to present business opportunities to us. By purchasing a common unit, the purchaser agrees to be bound by the terms of our partnership agreement, and each unitholder is treated as having consented to various actions and potential conflicts of interest contemplated in the partnership agreement that might otherwise be considered a breach of fiduciary or other duties unde Delaware law.

For a more detailed description of the conflicts of interest and duties of our general partner and its directors and officers, please read "Conflicts of Interest and Fiduciary Duties." For a description of

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other relationships with our affiliates, please read "Certain Relationships and Related Party Transactions."

IPO Reorganization and Partnership Structure

We are a Delaware limited partnership formed in January 2015 by our general partner and our sponsor. In connection with the closing of this offering, we expect that the following transactions will occur (the "IPO Reorganization"):

- Canyon Fuel Company, LLC ("CFC") will distribute all cash and cash equivalents, including accounts receivable, to our sponsor.
- Our sponsor will transfer or cause to be transferred 100% of the equity interests in (i) CFC, including CFC's subsidiary, Fossil Rock Resources, LLC, and (ii) Hunter Prep Plant, LLC to us in exchange for (a) common units (common units if the underwriters exercise their option to purchase additional common units in full) and subordinated units and (b) a right to receive a cash distribution of up to $ million from us as reimbursement for capital expenditures.
- We will issue incentive distribution rights ("IDRs") to our general partner.
- After satisfaction of the Escrow Release Conditions, we will become a co-issuer of the New Notes and a party to the indenture governing the New Notes, and will receive $ million of net proceeds (after payment of underwriting discounts) from the offering o New Notes.
- We will enter into a new $ million revolving credit facility under which $ million will be drawn as of the closing of this offering.
- CFC will be released as a guarantor under our sponsor's Senior Secured Credit Facilities (defined herein), and the liens on the assets contributed to us and securing borrowings under these facilities will be released.
- We will enter into a coal supply agreement with our sponsor pursuant to which it will purchase substantially all of our coal on substantially the same terms as our sponsor's agreements with our end customers. Please read "Certain Relationships and Related Part Transactions—Agreements with Affiliates in Connection with the Transactions—Coal Supply Agreement with Our Sponsor."
- CFC, our sponsor and Trafigura AG will terminate the existing Coal Services Agreement and our operating company and its subsidiaries will enter into a new Coal Services Agreement with our sponsor and Trafigura AG. Please read "Certain Relationships an Related Party Transactions—Agreements with Affiliates in Connection with the Transactions—Coal Services Agreement."
- We will enter into an omnibus agreement and certain other agreements with our sponsor and its affiliates, as described in "Certain Relationships and Related Party Transactions—Agreements with Affiliates in Connection with the Transactions."
- We will issue and sell common units to the public and will use the net proceeds therefrom, together with the net proceeds from our offering of New Notes, as described under "Use of Proceeds."

We have granted the underwriters a 30-day option to purchase up to an aggregate of additional common units to cover over-allotments. Any net proceeds received from the exercise of this option will be used to make a distribution to our sponsor as reimbursement for capital expenditures. If the underwriters do not exercise this option in full or at all, the common units that would have been sold to the underwriters had they exercised the option in full will be issued to our sponsor for no

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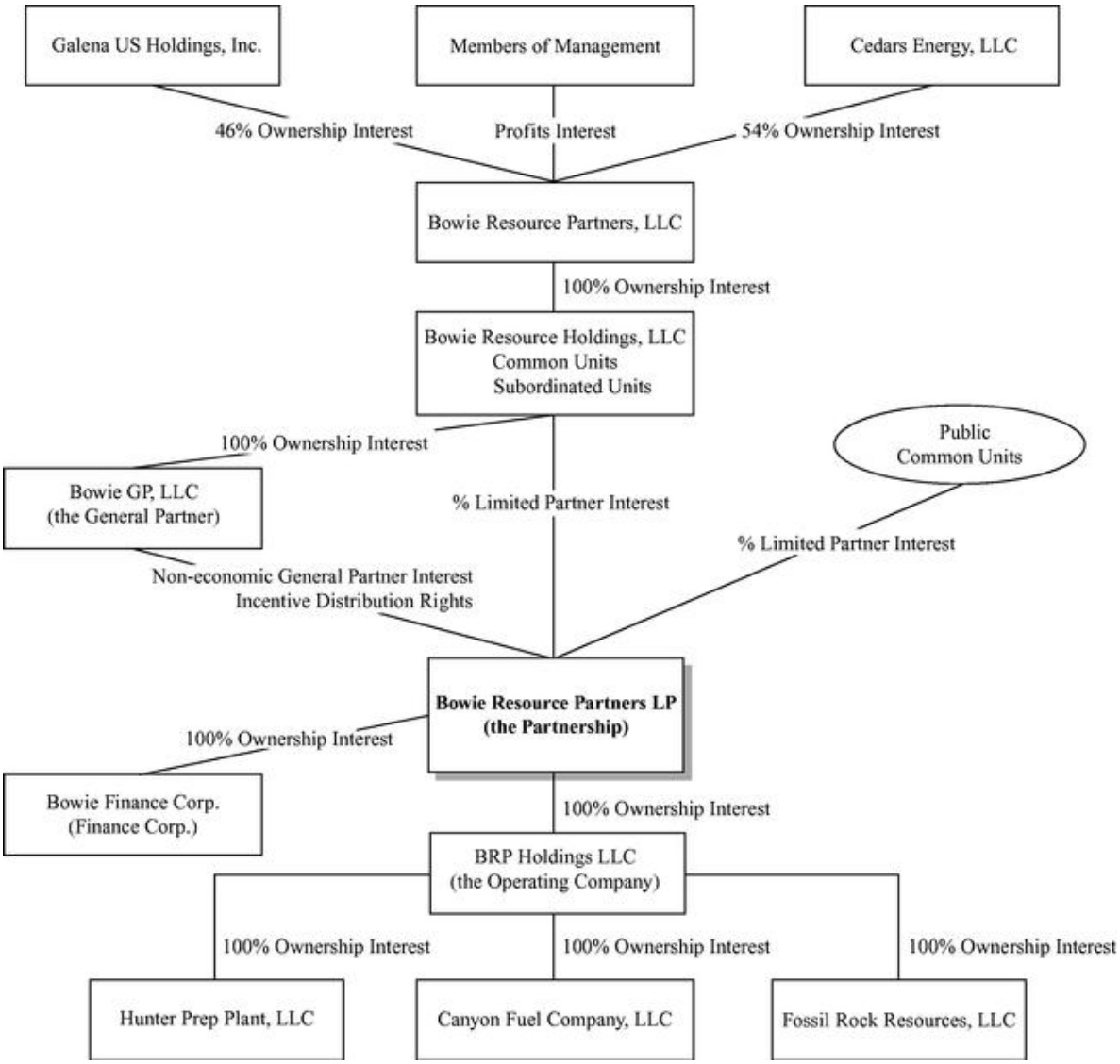
additional consideration at the expiration of the option period. Accordingly, the exercise of the underwriters' option will not affect the total number of common units outstanding.

The following chart summarizes our structure after giving effect to the IPO Reorganization, including this offering and the use of proceeds therefrom:



(1) Prior to the IPO Reorganization and in connection with the closing of the Utah Transaction, Fossil Rock Resources, LLC acquired the Fossil Rock reserves from an affiliate of PacifiCorp and Hunter Prep Plant, LLC acquired certain real property from PacifiCorp. Neither entity had a history of operations, nor did they own any assets until the closing of the Utah Transaction.

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Our Emerging Growth Company Status

We are an "emerging growth company" as defined in the Jumpstart Our Business Startups Act of 2012 ("JOBS Act"). For as long as we are an emerging growth company, unlike other public companies, we will not be required to:

- provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financia reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002;
- comply with any new requirements adopted by the Public Company Accounting Oversight Board ("PCAOB") requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer;
- comply with any new audit rules adopted by the PCAOB after April 5, 2012, unless the SEC determines otherwise;
- provide certain disclosure regarding executive compensation required of larger public companies; or
- submit for unitholder approval golden parachute payments not previously approved.

We will cease to be an "emerging growth company" upon the earliest of:

- when we have $1.0 billion or more in annual revenues;
- when we have at least $700 million in market value of our common units held by non-affiliates;
- when we issue more than $1.0 billion of non-convertible debt over a three-year period; or
- the last day of the fiscal year following the fifth anniversary of our initial public offering.

In addition, Section 107 of the JOBS Act also provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards. In other words, an emerging growth company can delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. However, we are choosing to "opt out" of such extended transition period, and as a result, we will comply with new or revised accounting standards on the relevant dates on which adoption of such standards is required for non-emerging growth companies. Section 107 of the JOBS Act provides that our decision t opt out of the extended transition period for complying with new or revised accounting standards is irrevocable.

Please read "Risk Factors—Risks Inherent in an Investment in Us—For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements that apply to other public companies, including those relating to auditing standards and disclosure abou our executive compensation."

Partnership Information

Our principal executive offices are located at 6100 Dutchmans Lane, 9th Floor, Louisville, Kentucky 40205. Our phone number is (502) 584-6022. Our website address is . We intend to make our periodic reports and other information filed with or furnished to the SEC available, free of charge, through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

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The Offering

Common units offered to the public	common units. common units if the underwriters exercise in full their option to purchase additional common unit to cover over-allotments.
Units outstanding after this offering	common units and subordinated units. The exercise of the underwriters' option will not affect the total number of common units outstanding. Please read "—IPO Reorganization and Partnership Structure."
Use of proceeds	We expect to receive approximately $ million of net proceeds from the sale of common units by u in this offering (based on an assumed initial offering price of $ per common unit, the mid-point of the price range set forth on the cover page of this prospectus), after deducting the estimated underwriting discounts and offering expenses. Assuming the Escrow Release Conditions have been satisfied, concurrently with the closing of this offering, we expect to receive approximately $ million of net proceeds from our offering of $ million aggregate principal amount of New Notes. We intend to use the net proceeds of this offering and our offering of the New Notes as follows: (i) $ million to make a cash distribution to our sponsor, in part as reimbursement for capital expenditures, (ii) $ million to repay a $30 million promissory note and a $10 million promissory note, each issued to PacifiCorp or its affiliate in connection with the Utah Transaction (the "PacifiCorp Notes"), (iii) $ million to repay CFC's outstanding equipment notes with Prudential Insurance Company of America (collectively, the "Prudential Notes") and (iv) $ million for general partnership purposes Please read "Use of Proceeds" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Long-Term Debt—Prudential Notes." If the underwriters exercise their option to purchase additional common units in full, the additional net proceeds to us would be approximately $ million (based on an assumed initial offering price of $ per common unit, the mid-point of the price range set forth on the cover page of this prospectus) The net proceeds from any exercise of such option will be used to make a cash distribution to our sponso in part as reimbursement for capital expenditures. If the underwriters do not exercise their option, we wil issue such additional common units to our sponsor upon the expiration of the option. We expect that a portion of the net proceeds distributed to our sponsor will be used by our sponsor to repay outstanding indebtedness under our sponsor's Senior Secured Credit Facilities (defined herein). Please read "Use of Proceeds." We

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	expect that Cedars, which is directly or indirectly owned or controlled by certain of our directors and director nominees, will receive $ million (or $ million if the underwriters exercise their option to purchase additional units) of the net proceeds from this offering as a result of the distribution by our sponsor of a portion of the proceeds it receives from us, and that our executive officers will receive a aggregate of $ million (or $ million if the underwriters exercise their option to purchase additional units) in connection with this offering from the cash distribution made to our sponsor pursuant to a sponsor-level bonus arrangement. Please read "Certain Relationships and Related Party Transactions—Agreements with Affiliates in Connection with the Transactions—Ownership Interests in our Sponsor and Arrangements with Management." Affiliates of certain of the underwriters are lenders under our sponsor's Senior Secured Credit Facilities and, accordingly, may ultimately receive a portion of the net proceeds from the offering of our New Notes. Certain of the underwriters are also initial purchasers in connection with the New Notes offering. Please read "Underwriting."
Cash distributions	Within 60 days after the end of each quarter, we expect to make a cash distribution to holders of our common units and subordinated units. We expect to make a minimum quarterly distribution of $ per common unit and subordinated unit ($ per common unit and subordinated unit on an annualized basis) to the extent we have sufficient cash after the establishment of cash reserves and the payment of fees and expenses, including payments to our general partner and its affiliates. For the first quarter that we are publicly traded, we will pay a prorated distribution covering the period after the consummation of this offering through , 2015, based on the actual length of that period. The board of directors of our general partner will adopt a policy pursuant to which distributions for each quarter will be paid to the extent we have sufficient cash after establishment of cash reserves and paymer of fees and expenses, including payments to our general partner and its affiliates. Our ability to pay the minimum quarterly distribution is subject to various restrictions and other factors described in more deta in "Cash Distribution Policy and Restrictions on Distributions." Our partnership agreement generally provides that we will distribute cash each quarter during the subordination period in the following manner: • *first*, to the holders of common units, until each common unit has received the minimum quarterly distribution of $ plus any arrearages from prior quarters;

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- *second*, to the holders of subordinated units, until each subordinated unit has received the minimum quarterly distribution of $; and

- *third*, to the holders of common units and subordinated units, pro rata, until each has received a distribution of $.

If cash distributions to our unitholders exceed $ per unit on all common and subordinated units in any quarter, our unitholders and our general partner, as the holder of our IDRs, will receive distributions according to the following percentage allocations:

Total Quarterly Distribution Target Amount		Marginal Percentage Interest in Distributions	
		Unitholders	General Partner (as holder of IDRs)
above $	up to $	85.0%	15.0%
above $	up to $	75.0%	25.0%
above $		50.0%	50.0%

We refer to the additional increasing distributions to our general partner as "incentive distributions." Please read "How We Make Distributions To Our Partners—Incentive Distribution Rights."

Pro forma cash available for distribution for the year ended December 31, 2014 and the twelve months ended March 31,

2015 were approximately $ and $, respectively. The amount of cash available for distribution for the year ended December 31, 2014 and the twelve months ended March 31, 2015 on a pro forma basis would not have been sufficient to allow us to pay the full minimum quarterly distribution on all of our common units and subordinated units during those periods. For a calculation of our ability to make distributions to our unitholders based on our pro forma results of operations for the year ended December 31, 2014 and the twelve months ended March 31, 2015, please read "Cash Distribution Policy and Restrictions on Distributions—Unaudited Pro Forma Cash Available for Distribution."

We believe, based on our financial forecast and related assumptions included in "Cash Distribution Policy and Restrictions on Distributions," that we will have sufficient cash available for distribution to pay the minimum quarterly distribution of $ on all of our common units and subordinated units for the twelve months ending June 30, 2016. However, we do not have a legal or contractual obligation to pay distributions quarterly or on any other basis or at the minimum quarterly distribution rate or at any other rate, and there is no guarantee that we will pay distributions to our unitholders in any quarter. Our actual results of operations, cash flows and financial condition during the forecast period may vary from the forecast, and there is no guarantee that we will make quarterly cash distributions to our

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	unitholders. Please read "Cash Distribution Policy and Restrictions on Distributions."
Eligible Holders and redemption	To comply with certain U.S. laws relating to the ownership of interests in mineral leases on federal lands transferees may be required to fill out a properly completed transfer application certifying, and our general partner, acting on our behalf, may at any time require each unitholder to re-certify, that the unitholder is an Eligible Holder. As used herein, an Eligible Holder means a person or entity qualified to hold an interest in mineral leases on federal lands. If a transferee or a common unitholder, as the case ma be, is not an Eligible Holder, the transferee or common unitholder may not have any right to receive any distributions or allocations of income or loss on its common units or to vote its common units on any matter, and we have the right to redeem such common units at a price which is equal to the then-current market price of such common units. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner. Please read "The Partnership Agreement —Non-Eligible Holders; Redemption."
Subordinated units	Our sponsor will initially own all of our subordinated units. The principal difference between our common units and subordinated units is that for any quarter during the subordination period, holders of the subordinated units will not be entitled to receive any distribution from operating surplus until the common units have received the minimum quarterly distribution from operating surplus for such quarter plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Subordinated units will not accrue arrearages.
Conversion of subordinated units	The subordination period will end on the first business day after we have earned and paid an aggregate amount of at least $ (the minimum quarterly distribution on an annualized basis) multiplied by the total number of outstanding common and subordinated units for each of three consecutive, non-overlapping four-quarter periods ending on or after , 2018 and there are no outstanding arrearages on our common units. Notwithstanding the foregoing, the subordination period will end on the first business day after we have paid an aggregate amount of at least $ (150.0% of the minimum quarterly distribution on an annualized basis) multiplied by the total number of outstanding common and subordinated units and we have earned that amount plus the related distribution on the incentive distribution rights, for any four-quarter period ending on or after , 2016 and there are no outstanding arrearages on our common units. When the subordination period ends, all subordinated units will convert into common units on a one-for-one basis, and all common units will thereafter no longer be entitled to arrearages.

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General partner's right to reset the target distribution levels	Our general partner, as the initial holder of our incentive distribution rights, will have the right, at any time when there are no subordinated units outstanding and we have made distributions in excess of the highest then-applicable target distribution for the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our cash distributions at the time of the exercise of the reset election. If our general partner transfers all or a portion of our incentive distribution rights in the future, then the holder or holders of a majority of our incentive distribution rights will be entitled to exercise this right. Following a reset election, the minimum quarterly distribution will be adjusted to equal the distribution for the quarter immediately preceding the reset, and the target distribution levels will be reset to correspondingly higher levels based on the same percentage increases above the reset minimum quarterly distribution as the initial target distribution levels were above the minimum quarterly distribution. If the target distribution levels are reset, the holders of our incentive distribution rights will be entitled to receive common units. The number of common units to be issued will equal the number of common units that would have entitled the holders of our incentive distribution rights to an aggregate quarterly cash distribution for the quarter prior to the reset election equal to the distribution on the incentive distribution rights for the quarter prior to the reset election. Please read "How We Make Distributions To Our Partner —Incentive Distribution Rights—Incentive Distribution Right Holders' Right to Reset Incentive Distribution Levels."
Issuance of additional units	Our partnership agreement authorizes us to issue an unlimited number of additional units without the approval of our unitholders. Please read "Units Eligible for Future Sale" and "The Partnership Agreemen —Issuance of Additional Interests."
Limited voting rights	Our general partner will manage and operate us. Unlike the holders of common stock in a corporation, ou unitholders will have only limited voting rights on matters affecting our business. Our unitholders will have no right to elect our general partner or its directors on an annual or other continuing basis. Our general partner may not be removed except by a vote of the holders of at least $66^2/_3$% of the outstanding units, including any units owned by our general partner and its affiliates, voting together as a single class Upon consummation of this offering, our sponsor will own an aggregate of % of our outstanding units (or % of our outstanding units, if the underwriters exercise their option to purchase additiona common units in full). This will give our sponsor the ability to prevent the removal of our general partne In addition, any vote to remove our general partner during the subordination period must provide for the

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	majority of the common units and a majority of the subordinated units, voting as separate classes. This will provide our sponsor the ability to prevent the removal of our general partner. Please read "The Partnership Agreement—Voting Rights."
Limited call right	If at any time our general partner and its affiliates own more than 80% of the outstanding common units, our general partner may purchase all of the remaining common units at a price equal to the greater of (1) the average of the daily closing price of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (2) the highest per-unit price paid by our general partner or any of its affiliates for common units during the 90-day period preceding the date such notice is first mailed. Please read "The Partnership Agreement—Limited Call Right."
Estimated ratio of taxable income to distributions	We estimate that if you own the common units you purchase in this offering through the record date for distributions for the period ending December 31, , you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be less than % of the cash distributed to you with respect to that period. For example, if you receive an annual distribution of $ per unit, we estimate that your average allocable federal taxable income per year will be no more than approximately $ per unit. Thereafter, the ratio of allocable taxable income to cash distributions to you could substantially increase. Please read "Material U.S. Federal Income Tax Consequences—Tax Consequences of Unit Ownership" for the basis of this estimate.
Material federal income tax consequences	For a discussion of the material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States, please read "Material U.S. Federal Income Tax Consequences."
Exchange listing	We intend to apply to list our common units on the New York Stock Exchange ("NYSE") under the symbol "BRLP."

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Summary Historical and Pro Forma Financial and Other Data

The following table sets forth our summary historical and pro forma financial and other data, as of the dates and for the periods indicated. The summary historical financial data presented as of August 16, 2013 and for the period from January 1, 2013 to August 16, 2013 have been derived from the audited financial statements of CFC prior to the acquisition of CFC by our sponsor on August 16, 2013 (the "Predecessor"), included elsewhere in this prospectus. The summary historical financial data presented as of December 31, 2013, for the period from August 16, 2013 to December 31, 2013 and as of and for the year ended December 31, 2014 have been derived from the audited financial statements of CFC after the acquisition of CFC by our sponsor (the "Successor"), included elsewhere in this prospectus.

The summary historical financial data presented as of and for the three months ended March 31, 2014 and 2015 have been derived from the unaudited interim financial statements of the Successor included elsewhere in this prospectus. The unaudited interim financial statements have been prepared on the same basis as the Successor's audited financial statements and, in the opinion of our management, include all material adjustments, consisting of normal and recurring adjustments, necessary for a fair presentation of the information set forth herein. The summary historical interim balance sheet data as of March 31, 2014 have been derived from unaudited interim financial statements of the Successor, which are not included in this prospectus. Operating results for the three months ended March 31, 2015 are not necessarily indicative of the results that may be expected for the year ended December 31, 2015 or for any future period.

The summary unaudited pro forma financial data presented as of and for the year ended December 31, 2014 and the three months ended March 31, 2015 have been derived from the unaudited pro forma condensed consolidated financial statements of Bowie Resource Partners LP, included elsewhere in this prospectus. The unaudited pro forma condensed consolidated financial statements of Bowie Resource Partners LP give pro forma effect to the IPO Reorganization described under "—IPO Reorganization and Partnership Structure." The unaudited pro forma condensed consolidated balance sheet as of March 31, 2015 reflects the IPO Reorganization as if it occurred on March 31, 2015. The pro forma condensed consolidated statement of (loss) income for the year ended December 31, 2014 and the three months ended March 31, 2015 reflect the IPO Reorganization as if it occurred on January 1, 2014.

We have not given pro forma effect to incremental selling, general and administrative expenses of approximately $ that we expect to incu annually as a result of operating as a publicly traded partnership.

The summary historical and pro forma financial and other data presented below should be read in conjunction with the information presented under "Selected Historical and Pro Forma Financial and Other Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements and related notes thereto appearing in this prospectus.

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	Predecessor		Successor				
	Year Ended December 31, 2013					Bowie Resource Partners LP Pro Forma	
	Period from January 1, 2013 to August 16, 2013	Period from August 16, 2013 to December 31, 2013	Year Ended December 31, 2014	Three Months Ended March 31, 2014	Three Months Ended March 31, 2015	Year Ended December 31, 2014	Three Months Ended March 31, 2015
	(in thousands, except per ton data)						
Statements of Operations Data							
Coal sales	$ 219,140	$ 158,756	$ 419,804	$ 112,265	$ 103,924	$	$
Other revenues, net(1)	813	1,410	358	89	91		
Costs and expenses:							
Cost of coal sales, exclusive of items shown separately below	140,781	96,165	232,819	63,115	61,629		
Transportation	30,477	19,690	44,439	12,758	12,808		
Depreciation, depletion and amortization	21,955	27,251	81,057	18,592	21,334		
Accretion on asset retirement obligations	462	—	785	196	206		
Selling, general and administrative expenses	7,970	9,586	17,590	3,159	4,173		
Amortization of acquired sales contracts, net	—	3,708	12,098	3,181	(54)		
Operating income	18,308	3,766	31,374	11,353	3,919		
Other expenses (income):							
Interest expense and related financing costs	—	13,604	36,245	9,093	8,021		
Gain on sale of assets	(389)	—	—	—	—		
Other	769	—	—	—	—		
Net income (loss)	$ 17,928	$ (9,838)	$ (4,871)	$ 2,260	$ (4,102)	$	$
Cash Flow Data							
Net cash provided by operating activities	$ 45,964	$ 14,858	$ 84,524	$ 12,941	$ 5,454		
Net cash used in investing activities	$ (5,217)	$ (8,373)	$ (27,044)	$ (1,119)	$ (5,960)		
Net cash (used in) provided by financing activities	$ (40,807)	$ (6,485)	$ (57,480)	$ (11,822)	$ 506		
Balance Sheet Data (at period end)							
Total current assets	$ 51,857	$ 82,093	$ 84,655	$ 80,907	$ 93,375		$
Property, plant and equipment, net	$ 285,934	$ 400,945	$ 357,110	$ 385,612	$ 344,557		$
Other assets	$ 5,192	$ 36,615	$ 17,659	$ 36,701	$ 16,203		$
Total liabilities	$ 51,430	$ 495,027	$ 440,104	$ 480,497	$ 446,069		$
Member's equity	$ 291,553	$ 24,626	$ 19,320	$ 22,723	$ 8,066		$
Total liabilities and member's equity	$ 342,983	$ 519,653	$ 459,424	$ 503,220	$ 454,135		$
Other Data							
EBITDA(2)	$ 39,883	$ 34,725	$ 124,529	$ 33,126	$ 25,199	$	$
Adjusted EBITDA(2)	$ 40,725	$ 34,725	$ 125,314	$ 33,322	$ 25,405	$	$
Tons produced	5,793	3,863	11,386	2,935	2,518		
Tons sold	5,614	4,440	11,463	3,175	2,691		
Coal sales realized per ton(3)	$ 39.03	$ 35.76	$ 36.62	$ 35.36	$ 38.62	$	$
Direct mining costs per ton(4)	$ 25.08	$ 21.66	$ 20.31	$ 19.88	$ 22.90	$	$

(1) Primarily includes net revenues from contract terminations (bookouts), restructuring payments, royalties related to coal lease agreements and revenues from property and facility rentals.

(2) Please read "—Non-GAAP Financial Measures" below for the definitions of EBITDA and Adjusted EBITDA and a reconciliation of EBITDA and Adjusted EBITDA to our most directly comparable financial measure, calculated and presented in accordance with GAAP.

(3) Coal sales realized per ton is defined as coal sales divided by tons sold.

(4) Direct mining costs per ton is defined as cost of coal sales, exclusive of items shown separately, divided by tons sold.

Non-GAAP Financial Measures

EBITDA and Adjusted EBITDA are non-GAAP financial measures used by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others to assess:

- our ability to make distributions to our unitholders;
- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

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- the ability of our assets to generate sufficient cash to pay interest costs and support our indebtedness;
- our operating performance and return on capital as compared to those of other companies and partnerships in our industry, without regard to financing or capital structure; and
- the feasibility of acquisitions and other capital expenditures and the overall rates of return on investment opportunities.

We define EBITDA as net income (loss) before interest expense, income tax, depreciation, depletion and amortization. We define Adjusted EBITDA as EBITDA further adjusted for accretion of asset retirement obligations, gain or loss on sale of assets, casualty losses and other taxes.

EBITDA and Adjusted EBITDA should not be considered alternatives to, or more meaningful than, net income (loss), income from operations, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP as measures of our operating performance or liquidity. EBITDA and Adjusted EBITDA do not include changes in working capital, capital expenditures and other items that are set forth in cash flow statement presentation of our operating, investing and financing activities. Any measures that exclude these elements have material limitations. Our computations of EBITDA and Adjusted EBITDA may differ from computations of similarly titled measures of other companies.

The following table presents a reconciliation of EBITDA and Adjusted EBITDA to the most directly comparable GAAP financial measure for the periods indicated.

	Predecessor	Successor				Bowie Resource Partners LP Pro Forma	
	Year Ended December 31, 2013						
	Period from January 1, 2013 to August 16, 2013	Period from August 16, 2013 to December 31, 2013	Year Ended December 31, 2014	Three Months Ended March 31, 2014	Three Months Ended March 31, 2015	Year Ended December 31, 2014	Three Months Ended March 31, 2015
	(in thousands)						
Reconciliation of EBITDA and Adjusted EBITDA to Net income (loss) :							
Net income (loss)	$ 17,928	$ (9,838)	$ (4,871)	$ 2,260	$ (4,102)	$	$
Add:							
Depreciation, depletion and amortization	21,955	27,251	81,057	18,592	21,334		
Amortization of acquired sales contracts, net	—	3,708	12,098	3,181	(54)		
Interest expense and related financing costs	—	13,604	36,245	9,093	8,021		
EBITDA	39,883	34,725	124,529	33,126	25,199		
Add:							
Accretion on asset retirement obligations	462	—	785	196	206		
Gain on sale of assets	(389)	—	—	—	—		
Other	769	—	—	—	—		
Adjusted EBITDA	$ 40,725	$ 34,725	$ 125,314	$ 33,322	$ 25,405	$	$

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RISK FACTORS

An investment in our common units involves risks. Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should carefully consider the following risk factors, together with all of the other information included in this prospectus, in evaluating an investment in our common units.

If any of the following risks were to occur, our business, financial condition, results of operations and cash available for distribution could be materially adversely affected. In that case, we might not be able to make distributions on our common units, the trading price of our common units could decline, and you could lose all or part of your investment.

Risks Related to Our Business

We may not have sufficient cash from operations to pay the minimum quarterly distribution on our common and subordinated units following establishment of cash reserves and payment of costs and expenses, including reimbursement of expenses to our general partner. On a pro forma basis, we would not have had sufficient cash available for distribution to pay the full minimum quarterly distribution on all of our units for the year ended December 31, 2014 or the twelve months ended March 31, 2015.

We may not have sufficient cash each quarter to pay the full amount of our minimum quarterly distribution of $ per unit, or $ per unit per year, which will require us to have cash available for distribution of approximately $ per quarter, or $ per year, based on the number of common and subordinated units that will be outstanding immediately after the completion of this offering. The amount of cash we can distribute to holders of our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of coal we are able to produce from our properties, which could be adversely affected by, among other things, operating difficulties and unfavorable geologic conditions;
- the market price of coal;
- the level of our operating costs, including reimbursement of expenses to our general partner;
- the supply of and demand for domestic and foreign coal;
- the timing of shipment of our contractual coal sales which are based on annual, not quarterly, minimum purchases;
- the impact of delays in the receipt of, failure to maintain, or revocation of necessary governmental permits;
- the impact of delays in the receipt of, failure to maintain, or termination of necessary coal mining leases;
- the price and availability of other fuels;
- the impact of existing and future environmental and climate change regulations, including those impacting coal-fired power plants;
- the loss of, or significant reduction in, purchases by our largest customers;
- the cost of compliance with new environmental laws;
- the cost of power needed to run our mines;
- worker stoppages or other labor difficulties;

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- prevailing economic and market conditions;
- difficulties in collecting our receivables because of credit or financial problems of customers;
- the effects of new or expanded health and safety regulations;
- air emission, wastewater discharge and other environmental standards for coal-fired power plants or coal mines and technologies developed to help meet these standards;
- domestic and foreign governmental regulation, including changes in governmental regulation of the mining industry or the electric utility industry;
- the proximity to and capacity of transportation facilities;
- the availability of transportation infrastructure, including flooding and railroad derailments;
- competition from other coal suppliers;
- advances in power technologies;
- the efficiency of our mines;
- the pricing terms contained in our long-term contracts;
- cancellation or renegotiation of contracts;
- legislative, regulatory and judicial developments, including those related to the release of GHGs;
- inclement or hazardous weather conditions and natural disasters, such as heavy rain, high winds and flooding;
- transportation costs and availability of transportation;
- the availability of skilled employees;
- changes in tax laws; and
- force majeure events.

In addition, the actual amount of cash we will have available for distribution will depend on several other factors, including:

- the level and timing of capital expenditures we make;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in debt agreements to which we are a party;
- the amount of cash reserves established by our general partner and the amount of reimbursements to our general partner; and
- the cost of acquisitions.

The amount of cash we need to pay the minimum quarterly distribution for four quarters on all of our units to be outstanding immediately after

this offering is approximately $ million. The amount of cash available for distribution that we generated during the year ended December 31, 2014 and the twelve months ended March 31, 2015 on a pro forma basis would not have been sufficient to allow us to pay the full minimum quarterly distribution on all of our common units and subordinated units during that period. Please read "Cash Distribution Policy and Restrictions on Distributions" for

the calculations of our cash available for distribution for those periods and for a description of additional restrictions and factors that may affect our ability to pay cash distributions.

We are a holding company with no independent operations or assets. Distributions to our unitholders are dependent on cash flow generated by our subsidiaries.

We are a holding company. All of our operations are conducted, and all of our assets are owned, by our direct and indirect subsidiaries. Consequently, our cash flow and our ability to meet our obligations or to pay cash distributions to our unitholders will depend upon the cash flows of our subsidiaries and the payment of funds by our subsidiaries to us in the form of dividends or otherwise. The ability of our subsidiaries to make any payments to us will depend on their earnings, the terms of their indebtedness and legal restrictions applicable to them. In particular, the terms of certain indebtedness of our subsidiaries may place significant limitations on the ability of our subsidiaries to pay dividends to us, and thus on our ability to pay distributions to our unitholders. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources." In the event that we do not receive distributions or dividends from our subsidiaries, we may be unable to make cash distributions to our unitholders.

The assumptions underlying our forecast of cash available for distribution included in "Cash Distribution Policy and Restrictions on Distributions" are inherently uncertain and subject to significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause cash available for distribution to differ materially from our estimates.

Our forecast of cash available for distribution set forth in "Cash Distribution Policy and Restrictions on Distributions" has been prepared by management and we have not received an opinion or report on it from any independent registered public accountants. The assumptions underlying our forecast of cash available for distribution are inherently uncertain and are subject to significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause cash available for distribution to differ materially from our estimates. If we do not achieve our forecasted results, we may not be able to pay the minimum quarterly distribution or any amount on our common units or subordinated units, in which event the market price of our common units may decline materially.

The amount of cash we have available for distribution to our unitholders depends primarily on our cash flow and not solely on profitability, which may prevent us from making cash distributions during periods when we report net income.

The amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from reserves and working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may pay cash distributions during periods when we report net losses for financial accounting purposes and may not pay cash distributions during periods when we report net income.

Our level of indebtedness and the terms of our borrowings could adversely affect our ability to grow our business, our ability to make cash distributions to our unitholders and our credit ratings and profile.

From and after the satisfaction of the Escrow Release Conditions, which we expect to occur concurrently with the closing of this offering, the partnership will become a co-issuer of $ million in aggregate principal amount of New Notes and a party to the indenture governing the New Notes. In connection with the closing of this offering we also expect to enter into a new $ million revolving credit facility. We expect to have $ million of borrowings outstanding under the revolving credit facility at the closing of this offering. In the future, we may also incur additional indebtedness. The operating and financial restrictions and covenants in our New Notes and our new

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revolving credit facility and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand our operations or otherwise pursue our business activities. Our level of debt has important consequences to us, including the following:

- we need a portion of our cash flow to service our indebtedness, reducing the funds that would otherwise be available for operations, future business opportunities and cash distributions;
- the restrictions and covenants contained in the agreements governing our indebtedness may limit our ability to grant liens, borrow additional funds, engage in a merger, consolidation or dissolution, sell or otherwise dispose of assets, businesses and operations, make distributions to our unitholders, make acquisitions, investments and capital expenditures, enter into transactions with affiliates or materially alter the character of our business as conducted at the closing of this offering;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing; and
- a high level of debt may impair our ability to obtain additional financing, if necessary, for operating working capital, capital expenditures, acquisitions or other purposes, or such financing may not be available on favorable terms.

Our ability to comply with the covenants and restrictions contained in our New Notes and our new revolving credit facility and any future financing agreements may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional equity capital. We may be unable to effect any of these actions on satisfactory terms, or at all.

If we violate any of the restrictions, covenants, ratios or tests in our New Notes or our new revolving credit facility, a significant portion of our indebtedness may become immediately due and payable, our lenders' commitment to make further loans to us may terminate, and we might not have, or be able to obtain, sufficient funds to make these accelerated payments. Any such violation could also prohibit us from making distributions to our unitholders. Any subsequent replacement of our revolving credit facility or any new indebtedness could have similar or greater restrictions. For more information regarding our New Notes or new revolving credit facility, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Long-Term Debt."

Our access to credit and capital markets depends on the credit ratings assigned to our debt by independent credit rating agencies. A decrease in our credit ratings, for any reason including those discussed above, would increase our borrowing costs and adversely affect our ability to raise capital. In addition, we may not be able to obtain favorable credit terms from our suppliers, or they may require us to provide collateral, letters of credit, or other forms of security, which would increase our operating costs. As a result, a downgrade in our credit ratings could have a material adverse impact on our financial position, results of operations, and liquidity.

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Our sponsor's level of indebtedness and the terms of its borrowings could adversely affect our ability to grow our business, our ability to make cash distributions to our unitholders and our credit ratings and profile. Our ability to obtain credit in the future and our future credit rating may also be affected by our sponsor's level of indebtedness.

Our sponsor has a significant amount of debt. As of March 31, 2015, our sponsor had total debt of $439.0 million, substantially all of which is secured. In addition to its outstanding debt, as of March 31, 2015, our sponsor could have incurred an additional $16.0 million of senior secured indebtedness under its existing debt agreements. We expect that a portion of the net proceeds distributed to our sponsor in connection with this offering and our offering of the New Notes will be used by our sponsor to repay outstanding senior secured indebtedness under our sponsor's Senior Secured Credit Facilities (defined herein). Our sponsor's level of debt could increase its and our vulnerability to general adverse economic and industry conditions and require our sponsor to dedicate a substantial portion of its cash flow from operations to service its debt and lease obligations, thereby reducing the availability of its cash flow to fund its growth strategy, including capital expenditures, acquisitions and other business opportunities. Furthermore, a higher level of indebtedness at our sponsor increases the risk that it may default on its obligations, including under our new coal supply agreement with our sponsor. The covenants contained in the agreements governing our sponsor's outstanding and future indebtedness may limit its ability to borrow additional funds for development and make certain investments and may directly or indirectly impact our operations in a similar manner.

Our credit rating may be adversely affected by the leverage and credit profile of our sponsor, as credit rating agencies such as Standard & Poor's Ratings Services and Moody's Investors Service, Inc. may consider the leverage and credit profile of our sponsor and its affiliates because of their ownership interest in and control of us and because our new coal supply agreement with our sponsor will account for substantially all of our revenues. Any adverse effect on our credit rating would increase our cost of borrowing or hinder our ability to raise financing in the capital markets, which would impair our ability to grow our business and make cash distributions to our unitholders.

In the event our sponsor were to default under certain of its debt obligations, we could be materially adversely affected. We have no control over whether our sponsor remains in compliance with the provisions of its debt obligations, except as such provisions may otherwise directly pertain to us. Further, any debt instruments that our sponsor or any of its affiliates enter into in the future, including any amendments to existing credit facilities, may include additional or more restrictive limitations on our sponsor that may impact our ability to conduct our business. These additional restrictions could adversely affect our ability to finance our future operations or capital needs or engage in, expand or pursue our business activities.

A significant increase in interest rates could adversely affect our ability to service our indebtedness.

In connection with the closing of this offering, we expect to enter into a new revolving credit facility. We anticipate that borrowings under the revolving credit facility will bear interest at a variable rate per annum. Therefore, we expect to have exposure to movements in interest rates. A significant increase in interest rates could adversely affect our ability to service our indebtedness. The increased cost could make the financing of our business activities more expensive. These added expenses could have an adverse effect on our results of operations, financial condition and our ability to pay distributions to our unitholders.

Our ability to generate the significant amount of cash needed to service our debt and financial obligations and our ability to refinance all or a portion of our indebtedness or obtain additional financing depends on many factors beyond our control.

Our ability to make scheduled payments on or to refinance our debt obligations depends on our financial condition and operating performance, which is subject to prevailing economic and competitive conditions and to certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to make payments on

our indebtedness. If we are unable to fund our debt service obligations, it will have an adverse effect on our results of operations, business and financial condition, as well as our ability to pay distributions to our unitholders.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investments and capital expenditures, or to sell assets, seek additional capital or restructure or refinance our indebtedness. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of our existing or future debt instruments may restrict us from adopting some of these alternatives. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations.

Penalties, fines or sanctions for violations of environmental or mine safety laws could have a material adverse effect on our business, results of operations and cash available for distribution.

MSHA and state regulators continuously inspect underground mines like ours and those of our competitors, which often leads to the issuance of notices of violation. Recently, regulators have been conducting more frequent and more comprehensive inspections of all coal mines, including ours. These enforcement practices create a risk that our operations will be cited for violations, including violations that may lead to material fines, penalties or sanctions. Our mines are at risk of a temporary or extended shut down as a result of an alleged violation. None of our violations to date has had a material impact on our operations or financial condition, but future violations may have a material adverse impact on our business, result of operations or financial condition.

Because most of the coal in the vicinity of our mines is owned by the U.S. federal government, our future success and growth would be affected if we are unable to acquire or are significantly delayed in the acquisition of additional reserves through the federal competitive leasing process.

The U.S. federal government owns most of the coal in the vicinity of our mines. Accordingly, the federal competitive leasing process, which is administered by the BLM, is our primary means of acquiring additional reserves. In order to win a lease and acquire additional coal, our bid for a coal tract must meet or exceed the fair market value of the coal based on the internal estimates of the BLM, which are not published, and must also exceed any third-party bids. The BLM, however, is not required to grant a lease even if it determines that a bid meets or exceeds the fair market value estimate. Furthermore, there is no requirement that the BLM must give preference to any lease by application ("LBA") applicant which means our bids for federal coal leases may compete with other coal producers' bids. Over time, federal coal leases have become increasingly more competitive and expensive to obtain, and the review process to act on a lease for bid continues to lengthen. We expect this trend to continue. The increasing size of potential LBA tracts may make it easier for new mining operators to enter the market on economically viable terms and may, therefore, increase competition for federal coal leases.

In addition, increased opposition from non-governmental organizations and other third parties may also lengthen, delay or complicate the leasing process. Any failure or delay in acquiring a coal lease, or the inability to do so on economically viable terms, could cause our production to decline, and may adversely affect our business, cash flows and results of operations, perhaps materially. For example, in November 2014, two non-governmental organizations brought suit against the Secretary of the Interior and the BLM alleging that the BLM's coal leasing program is in violation of NEPA. Although the plaintiffs acknowledge that the BLM has generally complied with the requirements of NEPA with respect to individual coal leases, they assert that that the agency's failure to update its 1979 analysis of environmental impacts associated with the broader BLM federal coal management program to include the impacts of GHGs constitutes a violation of NEPA. The plaintiffs are seeking a variety of relief, including an injunction that would, if their efforts are successful, prevent the issuance of new coal leases or modifications until the BLM has satisfied the requirements of NEPA. Please read "—Risks

Related to Environmental, Health, Safety and Other Regulations" for more details regarding risks associated with our compliance with NEPA during the BLM federal leasing process. Further, certain non-governmental organizations have filed comments with the BLM and U.S. Forest Service regarding the BLM's decision to offer the Greens Hollow tract for lease, and have further filed an objection with the U.S. Forest Service objecting to that agency's Draft Record of Decision proposing to consent to the BLM's issuance of the Greens Hollow lease. Further, the leasing action related to the Flat Canyon tract by the BLM could also be challenged in the Department of Interior's Board of Land Appeals or in federal district court. The May 15, 2015 Notice of Lease Sale of the Flat Canyon tract prompted letters by several non-governmental organizations objecting to the lease sale on, among other things, environmental grounds. Such third-party challenges filed against the BLM and the U.S. Forest Service by environmental groups with respect to the LBA process generally, or in the Uinta Basin more specifically, may result in delays and other adverse impacts on the LBA process. Please read "Business—Coal Reserves and Non-Reserve Coal Deposits—Reserve Acquisition Process."

The leasing process also requires us to acquire rights to mine from certain surface owners overlying the coal before the federal government will agree to lease the coal. Surface rights are becoming increasingly more difficult and costly to acquire. Certain federal regulations provide a specific class of surface owners, also known as qualified surface owners ("QSOs"), with the ability to prohibit the BLM from leasing its coal. If a QSO owns the land overlying a coal tract, federal laws prohibit us from leasing the coal tract without first securing surface rights to the land, or purchasing the surface rights from the QSO. This right of QSOs allows them to exercise significant influence over negotiations to acquire surface rights and can delay the leasing process or ultimately prevent the acquisition of coal underlying their surface rights. If we are unable to successfully negotiate access rights with QSOs at a price and on terms acceptable to us, we may be unable to acquire federal coal leases on land owned by the QSO. Our profitability could be adversely affected, perhaps materially, if the prices to acquire land owned by QSOs increase.

Our future success depends upon our ability to obtain and maintain permits, rights and approvals necessary to mine all of our coal reserves.

In order to economically develop our reserves, we must obtain, maintain or renew various governmental permits, rights and approvals, including, as applicable, water rights. We make no assurances that we will be able to obtain, maintain or renew any of the governmental permits, rights or approvals that we need to continue developing our proven and probable coal reserves. The inability to conduct mining operations or obtain, maintain or renew permits, rights or approvals may have a material adverse effect on our results of operations, business and financial position, as well as the ability to pay distributions to our unitholders.

A substantial or extended decline in coal prices or increase in the costs of mining or transporting coal could have a material adverse effect on our results of operations and our ability to pay distributions to our unitholders.

Our results of operations depend, in part, on the margins that we receive on sales of our coal. Our margins reflect the price we receive for our coal over our cost of producing and transporting our coal and are impacted by many factors, including:

- the market price for coal;
- the amount of coal we are able to produce from our properties, which could be adversely affected by, among other things, operating difficulties and unfavorable geologic conditions;
- the supply of, and demand for, domestic and foreign coal;
- competition from other coal suppliers;
- advances in power technologies;
- the efficiency of our mines;

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- the pricing terms contained in our long-term contracts;
- cancellation or renegotiation of contracts;
- legislative, regulatory and judicial developments, including those related to the release of GHGs;
- the cost of using, and the availability of, other fuels, including the effects of technological developments;
- air emission, wastewater discharge and other environmental standards for coal-fired power plants and technologies developed to help meet these standards;
- delays in the receipt of, or failure to maintain, or revocation of necessary government permits;
- delays in the receipt of, or failure to maintain, or termination of necessary coal mining leases;
- inclement or hazardous weather conditions and natural disasters, such as heavy rain, high winds and flooding;
- the availability and cost or interruption of fuel, equipment and other supplies;
- transportation costs and availability of transportation;
- the availability of transportation infrastructure, including flooding and railroad derailments;
- the availability of skilled employees; and
- work stoppages or other labor difficulties.

Substantial or extended declines in the price that we receive for our coal or increases in the costs of mining or transporting our coal could have a material adverse effect on our results of operations and our ability to generate the cash flows we require to invest in our operations, satisfy our obligations and pay distributions to our unitholders.

We may not be able to obtain equipment, parts and raw materials in a timely manner, in sufficient quantities or at reasonable costs to support our coal mining and transportation operations.

We use equipment in our coal mining and transportation operations such as continuous miners, conveyors, shuttle cars, rail cars, locomotives, roof bolters, shearers and shields. We procure this equipment from a concentrated group of suppliers, and obtaining this equipment often involves long lead times. Occasionally, demand for such equipment by mining companies can be high and some types of equipment may be in short supply. Delays in receiving or shortages of this equipment, as well as the raw materials used in the manufacturing of supplies and mining equipment, which, in some cases, do not have ready substitutes, or the cancellation of our supply contracts under which we obtain equipment and other consumables, could limit our ability to obtain these supplies or equipment. In addition, if any of our suppliers experiences an adverse event, or decides to no longer do business with us, we may be unable to obtain sufficient equipment and raw materials in a timely manner or at a reasonable price to allow us to meet our production goals and our revenues may be adversely impacted. We use considerable quantities of steel, diesel fuel, explosives and other raw materials in the mining process. If the price of steel, diesel fuel, explosives or other raw materials increases substantially or if the value of the U.S. dollar declines relative to foreign currencies with respect to certain imported supplies or other products, our operating expenses could increase. Any of the foregoing events could materially adversely impact our results of operations, business and financial condition as well as our profitability and our ability to pay distributions to our unitholders.

Our business requires substantial capital expenditures, and we may not have access to the capital required to maintain full productive capacity at our mines.

Maintaining and expanding mines and infrastructure is capital intensive. Specifically, the exploration, permitting and development of coal reserves, mining costs, the maintenance of machinery and equipment and compliance with applicable laws and regulations require substantial capital expenditures. While a significant amount of the capital expenditures required to build-out our mines has been spent, we must continue to invest capital to maintain or to increase our production. Decisions

to increase our production levels could also affect our capital needs. We cannot assure you that we will be able to maintain our production levels or generate sufficient cash flow, or that we will have access to sufficient financing to continue our production, exploration, permitting and development activities at or above our present levels, and we may be required to defer all or a portion of our capital expenditures. Our results of operations, business and financial condition, as well as our ability to pay distributions to our unitholders may be materially adversely affected if we cannot make such capital expenditures.

Major equipment and plant failures could reduce our ability to produce and ship coal and materially adversely affect our results of operations.

We depend on several major pieces of mining equipment and preparation plants to produce and ship our coal, including longwall mining systems, preparation plants, and transloading and loadout facilities. If any of these pieces of equipment or facilities suffered major damage or were destroyed by fire, abnormal wear, flooding, incorrect operation, or otherwise, we may be unable to replace or repair them in a timely manner or at a reasonable cost which would impact our ability to produce and ship coal and materially adversely affect our results of operations, business and financial condition and our ability to pay distributions to our unitholders.

The amount of estimated maintenance capital expenditures our general partner is required to deduct from operating surplus each quarter could increase in the future, resulting in a decrease in available cash from operating surplus that could be distributed to our unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus each quarter estimated maintenance capital expenditures as opposed to actual maintenance capital expenditures in order to reduce disparities in operating surplus caused by fluctuating maintenance capital expenditures, such as reserve replacement costs or refurbishment or replacement of mine equipment. Our initial annual estimated maintenance capital expenditures for purposes of calculating operating surplus will be approximately $ million for the twelve months ending June 30, 2016. This amount is based on our current estimates of the amounts of cash expenditures we will be required to make in the future to maintain our long-term operating capacity or net income, which we believe to be reasonable. Our partnership agreement does not cap the amount of maintenance capital expenditures that our general partner may estimate. This amount has been taken into consideration in calculating our forecasted cash available for distribution in "Cash Distribution Policy and Restrictions on Distributions." The initial amount of our estimated maintenance capital expenditures may be more than our initial actual maintenance capital expenditures, which will reduce the amount of available cash from operating surplus that we would otherwise have available for distribution to our unitholders. The amount of estimated maintenance capital expenditures deducted from operating surplus is subject to review and change by the board of directors of our general partner at least once a year, with any change approved by the conflicts committee. In addition to estimated maintenance capital expenditures, reimbursement of expenses incurred by our general partner and its affiliates will reduce the amount of available cash from operating surplus that we would otherwise have available for distribution to our unitholders. Please read "—We may not have sufficient cash from operations to pay the minimum quarterly distribution on our common and subordinated units following establishment of cash reserves and payment of costs and expenses, including reimbursement of expenses to our general partner."

We face numerous uncertainties in estimating our economically recoverable coal reserves.

Coal is economically recoverable when the price at which coal can be sold exceeds the costs and expenses of mining and selling the coal. Forecasts of our future performance are based on, among other things, estimates of our recoverable coal reserves. We base our reserve information on engineering, economic and geological data assembled and analyzed by third parties and our staff, which includes various engineers and geologists. The reserve estimates as to both quantity and quality are updated from time to time to reflect production of coal from the reserves and new drilling or other data received. There are numerous uncertainties inherent in estimating quantities and qualities of coal

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and costs to mine recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves necessarily depend upon a number of variable factors and assumptions, any one of which may, if inaccurate, result in an estimate that varies considerably from actual results. These factors and assumptions include:

- the possible necessity of revising a mining plan;
- geologic and mining conditions, which may not be fully identified by available exploration data and may differ from our experience in areas we currently mine;
- market conditions, including contracted pricing, market pricing and overall demand for our coal;
- future coal prices, operating costs and capital expenditures;
- severance and excise taxes, royalties and development and reclamation costs;
- future mining technology improvements;
- the effects of regulation by governmental agencies;
- ability to obtain, maintain and renew all required permits and coal mining leases;
- employee health and safety needs; and
- historical production from the area compared with production from other producing areas.

As a result, actual coal tonnage recovered from identified reserve areas or properties and revenues and expenditures with respect to our production from reserves may vary materially from estimates. These estimates thus may not accurately reflect our actual reserves. Any material inaccuracy in our estimates related to our reserves could result in lower than expected revenues, higher than expected costs or decreased profitability which could materially adversely affect our results of operations, business and financial condition as well as our ability to pay distributions to our unitholders.

Failure to meet certain provisions in our coal supply agreements could result in economic penalties.

Most of our coal supply agreements contain provisions requiring delivery of coal within certain ranges for specified coal characteristics such as heat content, sulfur, ash, grindability, chlorine and ash fusion temperature. Failure to meet these conditions could result in economic penalties, purchasing replacement coal in a higher priced open market, rejection of deliveries or termination of the agreements, at the election of the customer. If we are subject to economic penalties under the terms of our coal supply agreements, or if we are required to purchase replacement coal in the open market, our results of operations may be adversely affected, which could adversely affect our ability to make distributions to our unitholders.

Our coal supply agreements include price reset and other provisions that could result in lower contract prices.

Price adjustment, "price reset" and other similar provisions in our coal supply agreements may reduce the protection from short-term coal price volatility traditionally provided by such agreements. Price reset provisions are present in our coal supply agreements with IPA and PacifiCorp's Hunter Power Plant. Price reset provisions typically require the parties to agree on a new price. Failure of the parties to agree on a price under a price reset provision can lead to termination of the agreement or an automatic resetting of the price based on an agreed-upon formula. Certain of our price reset provisions are based on the applicable inflation rate, while others are based on a weighted average formula that takes into account a base price, the price of coal sold by us in prior periods and certain index pricing. If the rate of inflation is lower than expected, or if market prices are lower than the existing contract price, as applicable, pricing for these agreements could reset to lower levels.

Most of our coal supply agreements also contain provisions that permit the parties to adjust the contract price upward or downward for specific events, including changes in the laws or changes in the interpretation of laws that affect our costs related to performance of the agreements. These agreements also typically contain force majeure provisions allowing for the suspension of performance by the parties for the duration of specified events beyond the control of the affected party. Additionally, some

agreements may terminate upon continuance of an event of force majeure for an extended period. Any adjustment or renegotiations following such a termination and leading to a significantly lower contract price could adversely affect our results of operations and cash available for distribution to our unitholders.

Substantially all of our coal supply agreements are forward sales agreements. If the production costs underlying these agreements increase, our results of operations could be materially adversely affected.

Substantially all of our coal supply agreements are forward sales agreements under which customers agree to pay a specified price for coal to be delivered in future years. The profitability of these agreements depends on our ability to adequately control the costs of the coal production underlying the agreements. These production costs are subject to variability due to a number of factors, including increases in the cost of labor, supplies or other raw materials. To the extent our costs increase but pricing under these coal supply agreements remains fixed, we will be unable to pass increasing costs on to our customers. If we are unable to control our costs, our profitability under our forward sales agreements may be impaired and our results of operations, business and financial condition, and our ability to make distributions to our unitholders could be materially adversely affected.

A decrease in the use of coal by electric utilities could affect our ability to sell the coal we produce.

According to the World Coal Association, in 2013 coal was used to generate over 40% of the world's electricity needs. According to the EIA, in the United States, the domestic electricity generation industry accounts for approximately 93% of domestic thermal coal consumption. The use of coal as a fuel source, represented as a percentage of total U.S. electricity production, has declined to 38.7% in 2014 from 44.8% in 2010. The amount of coal consumed by the electric generation industry is affected primarily by the overall demand for electricity, environmental and other governmental regulations, as well as the price and availability of renewable energy sources, including biomass, hydroelectric, wind and solar power and other non-renewable fuel sources, including natural gas and nuclear power. For example, the relatively recent low price of natural gas has resulted, in some instances, in domestic generators increasing natural gas consumption while decreasing coal consumption. Moreover, on June 2, 2014, the EPA proposed new regulations limiting carbon dioxide emissions from existing power generation facilities. This or other future environmental regulation of GHG emissions could accelerate the use by utilities of fuels other than coal. Domestically, state and federal mandates for increased use of electricity derived from renewable energy sources could affect demand for our coal. A number of states have enacted mandates that require electricity suppliers to rely on renewable energy sources to generate a certain percentage of their power. Such mandates, combined with other incentives to use renewable energy sources, such as tax credits, could make alternative fuel sources more competitive with coal. Moreover, a wide range of recent regulatory developments, such as the MATS and CWA cooling water intake regulations, may make coal burning more expensive or less attractive for electric utilities and may lead to the closure of a number of coal-fired power plants. Other similar initiatives, such as potential revisions to the ozone NAAQSs or the EPA's proposed carbon pollution standard for new power plants, are still pending, but may have similar effects in the future. A decrease in coal consumption by the electric generation industry could adversely affect the price of coal, which could negatively affect our results of operations, business and financial condition, as well as our ability to pay distributions to our unitholders.

All of our revenue and cash flow will be derived from our coal supply agreements, and we will receive substantially all of our revenue and cash flow from our new coal supply agreement with our sponsor. Therefore, we will be subject to the business risks of our sponsor.

All of our revenue and cash flow will be derived from our coal supply agreements, and we will receive substantially all of our revenue and cash flow from our new coal supply agreement with our sponsor. As we expect to derive substantially all of our revenues through our sponsor for the foreseeable future, we will be subject to the risk of nonpayment or nonperformance by our sponsor under our coal supply agreement. Any event, whether related to our operations or otherwise, that

materially adversely affects our sponsor's financial condition, results of operations or cash flows may adversely affect our ability to sustain or increase cash distributions to our unitholders. Please read "—Our sponsor's level of indebtedness and the terms of its borrowings could adversely affect our ability to grow our business, our ability to make cash distributions to our unitholders and our credit ratings and profile. Our ability to obtain credit in the future and our future credit rating may also be affected by our sponsor's level of indebtedness."

Our sponsor is a privately owned company that does not disclose financial or operating results to the public, limiting the ability of our unitholders to assess the performance or financial outlook of our primary coal sales counterparty.

Our sponsor is a privately owned company and has no obligations to disclose publicly financial or operating information. Accordingly, our unitholders will have little to no insight into our sponsor's ability to meet its obligations to us and to our customers, including its coal purchase commitments under our new coal supply agreement with our sponsor. Our ability to make minimum quarterly distributions on all outstanding units will be adversely affected if: (i) our sponsor does not fulfill its obligations to us or our customers; or (ii) our sponsor's obligations under our new coal supply agreement are suspended, reduced or terminated and we are unable to generate additional revenues from third parties.

Our commercial agreements with our sponsor and Trafigura AG contain provisions that allow the counterparty to such agreement to suspend, reduce or terminate its obligations in certain circumstances including force majeure, which would have a material adverse effect on our results of operations, business, financial condition, and our ability to pay distributions to our unitholders.

We market and sell substantially all of our coal through our sponsor and Trafigura AG. A significant portion of our coal is sold under long-term coal supply agreements with our sponsor, which it sells to PacifiCorp and IPA. In addition, we sell coal to our sponsor that it exports through the U.S. West Coast terminals it leases. Our access to international markets is dependent on our relationship with our sponsor, as the lessee of the U.S. West Coast terminals, and Trafigura AG, as the exclusive marketer of our uncommitted coal. Each of our commercial agreements with our sponsor and Trafigura AG provides that our sponsor or Trafigura AG, as applicable, may suspend, reduce or terminate its obligations to us, if certain events occur. Additionally, Trafigura AG has the right to terminate its marketing arrangements with us at any time upon 180 days' notice. Any reduction, suspension or termination of any of our commercial agreements with our sponsor or Trafigura AG would have a material adverse effect on our results of operations, business and financial condition and our ability to pay distributions to our unitholders.

If Galena sells its interest in our sponsor, Trafigura AG will no longer be our affiliate, which could jeopardize our relationship with Trafigura AG.

Trafigura BV owns Galena Asset Management, which manages Galena, and also owns Trafigura AG, which is the exclusive marketer of our uncommitted coal. Galena owns a 46% interest in our sponsor. If Galena sells its interest in our sponsor, Trafigura AG will no longer be an affiliate of us or our sponsor, and Trafigura AG may decide to terminate its agreements with us. Any termination of our commercial agreements with Trafigura AG could have a material adverse effect on our results of operations, business condition and our ability to pay distributions to our unitholders.

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Certain of our customers may seek to defer contracted shipments of coal pursuant to the terms of our coal supply agreements or otherwise refuse to accept shipments of our coal, which could affect our results of operations and liquidity.

Our long-term coal supply agreements typically permit the parties to vary the timing of delivery within specified limits. From time to time, certain customers have sought and others may seek to delay shipments or request deferrals under existing agreements. There is no assurance that we will be able to resolve existing and potential deferrals on favorable terms, or at all. In addition, if our customers refuse to accept shipments of our coal for which they have an existing contractual obligation, our revenues may decrease until our customers' contractual obligations are honored. Any such delays, deferrals or refusals may have an adverse effect on our business, results of operations and financial condition, as well as our ability to pay distributions to our unitholders.

Our coal supply agreements do not provide for minimum coal sales on a quarterly basis and our coal sales may fluctuate from quarter to quarter.

Substantially all of our coal supply agreements have minimum annual purchase requirements, rather than minimum quarterly purchase requirements. Although the volume to be delivered under our coal supply agreements is stipulated, the parties may vary the timing of delivery within specified limits. Therefore, our revenues could be lower than projected on a quarterly basis, which could affect our ability to pay distributions to our unitholders.

Our ability to collect payments from our customers could be impaired if their creditworthiness deteriorates.

Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. Many utilities have sold their power plants to non-regulated affiliates or third parties that may be less creditworthy, thereby increasing the risk we bear on payment default. These new power plant owners may have credit ratings that are below investment grade. In addition, some of our customers have been adversely affected by the current economic downturn, which may impact their ability to fulfill their contractual obligations. Competition with other coal suppliers could force us to extend credit to customers and on terms that could increase the risk we bear on payment default. An inability to collect payment from these counterparties may materially adversely affect our results of operations, business and financial condition, as well as our ability to pay distributions to our unitholders.

The loss of, or significant reduction in, purchases by our largest customers could adversely affect our results of operations.

For the years ended December 31, 2014 and 2013, we derived approximately 24% and 26%, respectively, of our total coal revenues from sales of coal to PacifiCorp. For the years ended December 31, 2014 and 2013, we derived approximately 29% of our total coal revenues from sales of coal to IPA. If any of our top customers, especially PacifiCorp or IPA, were to significantly reduce their purchases of our coal, or if we were unable to sell coal to such customers on terms as favorable to us as the terms under our current coal supply agreements, our results of operations, business and financial condition, as well as our ability to pay distributions to our unitholders may be materially adversely affected. Additionally, our long-term contract for PacifiCorp's Hunter Power Plant is set to expire in 2020. Should we be unable to successfully renew such contract or any other contract with PacifiCorp or IPA upon its expiration, the reduction in the sale of our coal would adversely affect our results of operations, business and financial condition.

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Our operations are subject to risks, some of which are not insurable, and we cannot assure you that our existing insurance would be adequate in the event of a loss.

Insurance against certain risks, including certain liabilities for environmental pollution or hazards, may not be generally available to us or other companies within the mining industry. We cannot assure you that insurance coverage will be available in the future at commercially reasonable costs, or at all, or that the amounts for which we are insured or that we may receive, or the timing of any such receipt, will be adequate to cover all of our losses. Uninsured events may adversely affect our results of operations, business and financial condition, as well as our ability to pay distributions to our unitholders.

The geographic concentration of our mines creates a significant exposure to the risk of the local economy and other local adverse conditions.

All of our mining operations are located in the Uinta Basin in Utah and are therefore vulnerable to economic downturns in that region, as well as other factors, including adverse weather conditions. These mines are located within a relatively limited geographic area and 74% of our tons sold for the year ended December 31, 2014 were marketed in Utah, Nevada and California. As a result, we are more susceptible to regional conditions than the operations of more geographically diversified competitors and any unforeseen events or circumstances that affect the area could also materially adversely affect our results of operations. These factors include, among other things, changes in the economy, damages to infrastructure, weather conditions, demographics and population.

We have future mine closure and reclamation obligations, the timing of and amount for which are uncertain. In addition, our failure to maintain required financial assurances could affect our ability to secure reclamation and coal lease obligations, which could adversely affect our ability to mine or lease coal.

In view of the uncertainties concerning future mine closure and reclamation costs on our properties, the ultimate timing and future costs of these obligations could differ materially from our current estimates. We estimate our asset retirement liabilities for final reclamation and mine closure based upon detailed engineering calculations of the amount and timing of the future cash for a third party to perform the required work. Spending estimates are escalated for inflation and market risk premium, and then discounted at the credit-adjusted, risk-free rate. As of March 31, 2015, we had recorded total asset retirement obligations on our consolidated balance sheet of approximately $9.4 million. Our estimates for this future liability are subject to change based on new or amendments to existing applicable laws and regulation, the nature of ongoing operations and technological innovations. Although we accrue for future costs on our consolidated balance sheet, we do not reserve cash in respect of these obligations or otherwise fund these obligations in advance. As a result, we will have significant cash costs when we are required to close and restore mine sites that may, among other things, affect our ability to satisfy our obligations under our indebtedness and other contractual commitments and pay distributions to our unitholders. We cannot assure you that we will be able to obtain financing on satisfactory terms to fund these costs, or at all.

In addition, regulatory authorities require us to provide financial assurance to secure, in whole or in part, our future reclamation projects. The amount and nature of the financial assurances are dependent upon a number of factors, including our financial condition and reclamation cost estimates. Changes to these amounts, as well as the nature of the collateral to be provided, could significantly increase our costs, making the maintenance and development of existing and new mines less economically feasible. Currently, the security we provide consists of surety bonds. The premium rates and terms of the surety bonds are subject to annual renewals. Our failure to maintain, or inability to acquire, surety bonds or other forms of financial assurance that are required by applicable law, contract or permit could adversely affect our ability to operate. That failure could result from a variety of factors including the lack of availability, higher expense or unfavorable market terms of new surety

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bonds or other forms of financial assurance. There can be no guarantee that we will be able to maintain or add to our current level of financial assurance. Additionally, any capital resources that we do utilize for this purpose will reduce our resources available for our operations and commitments as well as our ability to pay distributions to our unitholders.

Defects in title or loss of any leasehold interests in our properties could limit our ability to conduct mining operations on these properties or result in significant unanticipated costs.

Substantially all of our coal reserves are leased from various landowners. Our main lessor is the U.S. government, from which we lease coal under terms set by Congress and administered by the BLM. The remainder of our coal reserves are leased from the State of Utah, land holding companies and various individuals. A title defect or the loss of any lease upon expiration of its term, upon a default or otherwise, could adversely affect our ability to mine the associated reserves or process the coal that we mine. Title to our owned or leased properties and mineral rights is not usually verified unless we are required by our lenders to obtain title policies or title opinions. In some cases, we rely on title information or representations and warranties provided by our lessors or grantors. Our right to mine certain of our reserves has in the past been, and may again in the future be, adversely affected if defects in title, boundaries or other rights necessary for mining exist or if a lease expires. Any challenge to our title or leasehold interests could delay the mining of the property and could ultimately result in the loss of some or all of our interest in the property. From time to time we also may be in default with respect to leases for properties on which we have mining operations. In such events, we may have to close down or significantly alter the sequence of such mining operations which may adversely affect our future coal production and future revenues. If we mine on property that we do not own or lease, we could incur liability for such mining and be subject to regulatory sanction and penalties.

In order to obtain, maintain or renew leases to conduct our mining operations on property where these defects exist, we may in the future have to incur unanticipated costs. Some leases have minimum production requirements. In addition, we may not be able to successfully negotiate new leases for properties containing additional reserves, or maintain our leasehold interests in properties where we have not commenced mining operations during the term of the lease. If any of our leases are terminated, for lack of diligent development or otherwise, we would be unable to mine the affected coal. As a result, our results of operations, business and financial condition, as well as our ability to pay distributions to our unitholders may be materially adversely affected.

The imposition of new taxes on the coal we produce could materially adversely affect our results of operations.

All of our operations are in Utah. Utah's state severance tax does not currently apply to coal production. If Utah were to impose its state severance tax on coal, or if Utah were to impose any other new tax on coal or otherwise on our Utah operations, we may be significantly impacted and our results of operations, business and financial condition, as well as the ability to pay distributions to our unitholders could be materially adversely affected. Any such imposition of a Utah state severance tax or any other tax could disproportionately impact us relative to our competitors that are more geographically diverse.

A shortage of skilled mining labor in the United States could decrease our labor productivity and increase our labor costs, which would adversely affect our profitability.

Efficient coal mining using complex and sophisticated techniques and equipment requires skilled laborers proficient in multiple mining tasks, including mining equipment maintenance. Any shortage of skilled mining labor reduces the productivity of experienced employees who must assist in training unskilled employees. If a shortage of experienced labor occurs, it could have an adverse impact on our labor productivity and costs and on our ability to expand production in the event there is an increase in

the demand for our coal, which could adversely affect our results of operations, business and financial condition, as well as our ability to pay distributions to our unitholders.

Our work force could become unionized in the future, which could negatively impact the stability of our production, materially reduce our profitability and increase the risk of work stoppages.

All of our mines are operated by non-union employees. Our employees have the right at any time under the National Labor Relations Act to form or affiliate with a union, and unions may conduct organizing activities in this regard. If our employees choose to form or affiliate with a union and the terms of a union collective bargaining agreement are significantly different from our current compensation and job assignment arrangements with our employees, these arrangements could negatively impact the stability of our production, materially reduce our profitability and increase the risk of work stoppages. In addition, even if our managed operations remain non-union, our business may still be adversely affected by work stoppages at our unionized transportation and service providers. For example, the recent labor dispute between the Pacific Maritime Association and the International Longshore and Warehouse Union disrupted vessel loadings at one of the U.S. West Coast export terminals leased by our sponsor.

Our ability to operate our business effectively could be impaired if we fail to attract and retain key personnel.

Our ability to operate our business and implement our strategies depends, in part, on the continued contributions of our executive officers and other key employees. The loss of any of our key senior executives could have a material adverse effect on our business unless and until we find a replacement. A limited number of persons exist with the requisite experience and skills to serve in our senior management positions. We may not be able to locate or employ qualified executives on acceptable terms. In addition, we believe that our future success will depend on our continued ability to attract and retain highly skilled personnel with coal industry experience. Competition for these persons in the coal industry is intense and we may not be able to successfully recruit, train or retain qualified managerial personnel. As a public company, our future success also will depend on our ability to hire and retain management with public company experience. We may not be able to continue to employ key personnel or attract and retain qualified personnel in the future. Our failure to retain or attract key personnel could have a material adverse effect on our ability to effectively operate our business.

Coal mining operations are subject to inherent risks and are dependent on many factors and conditions beyond our control, any of which may adversely affect our productivity and our financial condition.

Our mining operations, including our transportation infrastructure, are influenced by changing conditions that can affect the safety of our workforce, production levels, delivery of our coal and costs for varying lengths of time and, as a result, can diminish our revenues and profitability. In particular, underground mining and related processing activities present inherent risks of injury to persons and damage to property and equipment. A shutdown of any of our mines or prolonged disruption of production at any of our mines or transportation of our coal to customers would result in a decrease in our revenues and profitability, which could be material. Certain factors affecting the production and sale of our coal that could result in decreases in our revenues and profitability include:

- adverse geologic conditions including floor and roof conditions, variations in seam height, washouts and faults;
- fire or explosions from methane, coal or coal dust or explosive materials;
- industrial accidents;
- seismic activities, ground failures, rock bursts or structural cave-ins or slides;
- delays in the receipt of, or failure to maintain, or revocation of necessary government permits;

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- delays in the receipt of, or failure to maintain, or termination of necessary coal mining leases;
- changes in the manner of enforcement of existing laws and regulations;
- changes in laws or regulations, including permitting requirements and the imposition of additional regulations, taxes or fees;
- accidental or unexpected mine water inflows;
- delays in moving our longwall equipment;
- railroad derailments;
- inclement or hazardous weather conditions and natural disasters, such as heavy rain or snow, high winds and flooding;
- environmental hazards;
- interruption or loss of power, fuel, or parts;
- increased or unexpected reclamation costs;
- equipment availability, replacement or repair costs; and
- mining and processing equipment failures and unexpected maintenance problems.

These risks, conditions and events (1) could result in: (a) damage to, or destruction of value of, our coal properties, our coal production or transportation facilities, (b) personal injury or death, (c) environmental damage to our properties or the properties of others, (d) delays or prohibitions on mining our coal or in the transportation of coal, (e) monetary losses and (f) potential legal liability; and (2) could have a material adverse effect on our results of operations and our ability to generate the cash flows we require to invest in our operations and satisfy our debt obligations. Our insurance policies only provide limited coverage for some of these risks and will not fully cover these risks. A significant mine accident could potentially cause a mine shutdown, and could have a substantial adverse impact on our results of operations, financial condition or cash flows. These risks, conditions or events have had, and can be expected in the future to have, a significant adverse impact on our business and results of operations, as well as our ability to pay distributions to our unitholders.

Competition within the coal industry may adversely affect our ability to sell coal, and excess production capacity in the industry could put downward pressure on coal prices.

We compete with other producers primarily on the basis of price, coal quality, transportation cost and reliability of supply. We cannot assure you that competition from other producers will not adversely affect us in the future. The coal industry has experienced consolidation in recent years, including consolidation among some of our major competitors. As a result, a substantial portion of coal production is from companies that have significantly greater resources than we do. We cannot assure you that the result of current or further consolidation in the industry will not adversely affect us.

In addition, potential changes to international trade agreements, trade concessions or other political and economic arrangements may benefit coal producers operating in countries other than the United States, where our mining operations are currently located. We cannot assure you that we will be able to compete on the basis of price or other factors with companies that in the future may benefit from favorable trading or other arrangements. We compete directly for U.S. and international coal sales with numerous other coal producers located in the United States and internationally, in countries such as Mexico, Japan, China, Australia, Canada, India, South Africa, Indonesia, Russia and Colombia. The price of coal in the markets into which we sell our coal is also influenced by the price of coal in the markets in which we do not sell our coal because significant oversupply of coal from other markets could materially reduce the prices we receive for our coal. Increases in coal prices could encourage the

development of expanded capacity by new or existing coal producers, which could result in lower coal prices. In addition, coal is sold internationally in U.S. dollars and, as a result, general economic conditions in foreign markets and changes in foreign currency exchange rates may provide foreign producers of coal with a competitive advantage. If our competitors' currencies decline against the U.S. dollar or against our foreign customers' local currencies, those competitors may be able to offer lower prices for coal. Furthermore, if the currencies of our overseas customers were to significantly decline in value in comparison to the U.S. dollar, those customers may seek decreased prices for the coal we sell to them. As a result, our results of operations, business and financial condition, as well as our ability to pay distributions to our unitholders may be materially adversely affected.

The availability or reliability of current transportation facilities or disruptions in transportation services could affect the demand for our coal or temporarily impair our ability to supply coal to our customers. In addition, our inability to expand our transportation capabilities and options could further impair our ability to deliver coal efficiently to our customers.

We depend upon rail, truck, ocean-going vessels and port facilities to deliver coal to customers. Disruption of these transportation services because of weather-related problems, infrastructure damage, strikes, lock-outs, lack of fuel or maintenance items, transportation delays, lack of rail or port capacity or other events could temporarily impair our ability to supply coal to customers and thus could adversely affect our results of operations, cash flows and financial condition, as well as our ability to pay distributions to our unitholders.

Currently, we are required to utilize Savage Services Corporation ("Savage") to transport all of our coal from our Dugout Canyon mine. If there are significant disruptions in the services provided by Savage, or if we are unable to renew our agreement with Savage at favorable rates, then costs of transportation for coal produced at our Dugout Canyon mine could increase substantially until we arrange alternative transportation services for our Dugout Canyon mine. Additionally, we utilize the Union Pacific railroad for all of our rail shipments, and utilize the Port of Stockton, California, the Levin-Richmond Terminal in Richmond, California (the "Levin-Richmond Terminal"), and the Port of Long Beach, California for all of our exports. If there are disruptions of the transportation or transloading services provided by the relevant trucking company, railroad or port and we are unable to find alternative providers to enable us to deliver coal to our customers, our business and profitability could be adversely affected. While we currently have contracts in place for transportation and transloading of our coal and have continued to develop alternative options, there is no assurance that we will be able to renew these contracts or to develop these alternative options on terms that remain favorable to us. Any failure to do so could have a material adverse impact on our financial position and results of operations as well as our ability to pay distributions to our unitholders.

If our terminal agreements expire or are terminated, it may adversely affect our international coal sales and profitability.

Through our sponsor, we have access to throughput capacity of approximately 4.0 million tons per year at the Port of Stockton, California and approximately 1.7 million tons per year at the Levin-Richmond Terminal. The terminal contract between our sponsor and Metropolitan Stevedore Company with respect to the Port of Stockton expires on December 31, 2019, and the terminal contract between our sponsor and Levin-Richmond Terminal Corp. expires on December 31, 2015. Each agreement may also be terminated by either party upon the occurrence of certain customary events of default. If either one or both of these agreements expire and are not renewed or are otherwise terminated, it may adversely affect our international coal sales and profitability.

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Significant increases in transportation costs could make our coal less competitive when compared to other fuels or coal produced from other regions.

Transportation costs represent a significant portion of the total cost of coal for our customers and the cost of transportation is an important factor in a customer's purchasing decision. Increases in transportation costs, including increases resulting from emission control requirements and fluctuations in the price of diesel fuel and demurrage, could make coal a less competitive source of energy when compared to other fuels such as natural gas or could make our coal less competitive than coal produced in other regions of the United States or abroad. We depend upon the Union Pacific railroad to transport our coal to domestic customers and export terminal facilities. Reductions in service by the Union Pacific railroad or increases in railroad rates would increase our operating costs. Significant decreases in transportation costs, including lower rail rates, could result in increased competition from coal producers in other parts of the country and from abroad, including coal imported into the United States. Increased competition due to changing transportation costs, or alternatively higher rail rates, could have an adverse effect on our results of operations, business and financial condition, as well as our ability to pay distributions to our unitholders.

Our ability to mine and ship coal may be affected by adverse weather conditions, which could have an adverse effect on our revenues.

Adverse weather conditions can impact our ability to mine and ship our coal and our customers' ability to take delivery of our coal. Lower than expected shipments by us during any period could have an adverse effect on our revenues. In addition, severe weather may affect our ability to conduct our mining operations and severe rain, ice or snowfall may affect our ability to load and transport coal. If we are unable to conduct our operations due to severe weather, it could have an adverse effect on our results of operations, business and financial condition, as well as our ability to pay distributions to our unitholders.

Our revenues and operating profits could be negatively impacted if we are unable to extend existing coal supply agreements at favorable pricing or enter into new coal supply agreements due to competition, environmental regulations affecting our customers' changing coal purchasing patterns or other variables.

We compete with other coal suppliers when renewing expiring coal supply agreements or entering into new coal supply agreements. If we cannot renew these coal supply agreements or find alternate customers willing to purchase our coal, our revenue and operating profits could suffer. Our customers may decide not to extend our existing coal supply agreements or enter into new long-term agreements or, in the absence of long-term agreements, may decide to purchase fewer tons of coal than in the past or on different terms, including under different pricing terms or decide not to purchase at all. Any decrease in demand may cause customers to delay negotiations for new agreements or request lower pricing terms or seek coal from other sources. Furthermore, uncertainty caused by laws and regulations affecting electric utilities could deter customers from entering into long-term coal supply agreements with us. Some long-term agreements, including our coal supply agreements with PacifiCorp and IPA, contain provisions for termination or reduction in deliveries due to environmental changes if such changes prohibit or negatively impact those utilities' ability to burn the contracted coal.

We sell uncommitted tons in the spot market, which is subject to volatility.

We derive a portion of our revenue from coal sales in the spot market, typically defined as contracts with terms of less than one year. Trafigura AG, an affiliate of our sponsor, is the exclusive marketer of our uncommitted coal. The pricing in spot contracts is significantly more volatile than pricing through long-term coal supply agreements because it is subject to short-term demand swings. If spot market pricing for coal is unfavorable, this volatility could materially adversely affect our results of

operations, business and financial condition, as well as our ability to pay distributions to our unitholders.

Demand for export coal and export coal prices are closely linked to consumption patterns of the electric industry in China. Any changes in consumption patterns could affect our operations and profitability.

Demand for export coal and the prices we can obtain for our export coal are linked to coal consumption patterns of the electric generation industry in China, which has accounted for approximately 53% of overall thermal coal consumption in China in recent years. These coal consumption patterns are influenced by factors beyond our control, including the demand for electricity (which is dependent to a significant extent on summer and winter temperatures and the strength of the economy); government regulation; technological developments and the location, availability, quality and price of competing sources of coal; other fuels such as natural gas, oil and nuclear; and alternative energy sources such as hydroelectric power. Any reduction in the demand for export coal by the electric generation industry in China may cause a decline in export coal prices and our profitability.

In November 2014, the U.S. and Chinese governments issued a joint announcement on climate change. In the announcement, the Chinese government stated that it "intends to achieve the peaking of CO_2 emissions around 2030 and to make best efforts to peak early and intends to increase the share of non-fossil fuels in primary energy consumption to around 20% by 2030." Moreover, the countries stated that they would work together to seek the adoption of an international protocol with legal force to address climate change during the United Nations Climate Conference in Paris in 2015. While the announcement has not led to the enactment of any new statutes or the promulgation of any new rules, any new governmental regulation relating to GHG emissions in China could affect our customers' ability to use coal. Any switching of fuel sources in China away from coal, closure of existing coal-fired power plants, or reduced construction of new plants could adversely affect demand for and prices received for coal, perhaps materially.

The current challenging economic environment, along with difficult and volatile conditions in the capital and credit markets, could materially adversely affect our financial position, results of operations or cash flows, and we are unsure whether these conditions will improve in the future.

The U.S. economy and global credit markets remain volatile. Worsening economic conditions or factors that negatively affect the economic health of the United States, Europe and Asia could reduce our revenues and thus adversely affect our results of operations. These markets have historically experienced disruptions, including, among other things, volatility in security prices, diminished liquidity and credit availability, rating downgrades of certain investments and declining valuations of others, failure and potential failures of major financial institutions, unprecedented government support of financial institutions, high unemployment rates and increasing interest rates. Furthermore, if these developments continue or worsen it may adversely affect the ability of our customers and suppliers to obtain financing to perform their obligations to us. We believe that further deterioration or a prolonged period of economic weakness will have an adverse impact on our results of operations, business and financial condition, as well as our ability to pay distributions to our unitholders.

Terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war may negatively affect our business, financial condition and results of operations.

Terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war may negatively affect our business, financial condition and results of operations. Our business is affected by general economic conditions, fluctuations in consumer confidence and spending, and market liquidity, which can decline as a result of numerous factors outside of our control, such as terrorist attacks and acts of war. Future terrorist attacks against U.S. targets, rumors or threats of war, actual conflicts involving the United States or its allies, or military or trade disruptions affecting our

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customers could cause delays or losses in transportation and deliveries of coal to our customers, decreased sales of our coal and extension of time for payment of accounts receivable from our customers. Strategic targets such as energy-related assets may be at greater risk of future terrorist attacks than other targets in the United States. It is possible that any, or a combination, of these occurrences could have a material adverse effect on our business, financial condition and results of operations, as well as our ability to pay distributions to our unitholders.

The amount of our customers' coal inventories may have a negative impact on our business.

Our customers may experience increases or decreases in their respective coal inventories from time to time. If we are unable to meet customers' increased demand due to decreases in their respective coal inventories, we may experience a loss of customers which could have a negative impact on our results of operations. In addition, if customers experience an increase in coal inventory, it is possible that their demand for additional coal from us may decrease, which could have a negative impact on our results of operations.

If our seaborne coal sales are reduced, we may be obligated to pay liquidated damages under our terminal and rail agreements.

If demand for coal in the international market weakens, it may not be economical for us to sell our coal into the seaborne market. If we reduce our seaborne coal sales, we may be obligated to pay liquidated damages or stockpile maintenance fees, or we may forfeit guaranteed stockpile space, under the terms of our terminal agreements. If we reduce our seaborne coal sales, we may also be obligated to pay liquidated damages under the terms of our agreements with the Union Pacific.

Risks Related to Environmental, Health, Safety and Other Regulations

Our mining operations, including our transportation infrastructure, are extensively regulated, which imposes significant costs on us, and changes to existing and potential future regulations or violations of regulations could increase those costs or limit our ability to produce and sell coal.

The coal mining industry is subject to increasingly strict regulation by federal, state and local authorities on matters such as:

- permits and other licensing requirements including, as applicable, NEPA;
- surface subsidence from underground mining;
- miner health and safety;
- remediation of contaminated soil, surface water and groundwater;
- air emissions;
- water quality standards;
- the discharge of materials into the environment, including waste water;
- storage, treatment and disposal of petroleum products and substances which are regarded as hazardous under applicable laws or which, if spilled, could reach waterways or wetlands;
- storage and disposal of coal wastes, including coal slurry, under applicable laws;
- protection of human health, plant life and wildlife, including endangered and threatened species;
- reclamation and restoration of mining properties after mining is completed;
- wetlands protection;

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- dam permitting; and
- the effects, if any, that mining has on groundwater quality and availability.

Because of the extensive and detailed nature of these regulatory requirements, it is extremely difficult for us and other underground coal mining companies in particular, as well as the coal industry in general, to comply with all requirements at all times. We have been cited for violations of regulatory requirements in the past and we expect to be cited for violations in the future. None of our violations to date has had a material impact on our operations or financial condition, but future violations may have a material adverse impact on our business, results of operations or financial condition. While it is not possible to quantify all of the costs of compliance with applicable federal and state laws and associated regulations, those costs have been and are expected to continue to be significant. Compliance with these laws and regulations, and delays in the receipt of, or failure to receive or revocation of necessary government permits, could substantially increase the cost of coal mining or have a material adverse effect on our results of operations, cash flows and financial condition, as well as our ability to pay distributions to our unitholders. Because we engage in longwall mining at our Sufco and Skyline mines, subsidence issues are particularly important to our operations. Failure to timely secure subsidence rights or any associated mitigation agreements, or any related regulatory action, could materially affect our results by causing delays or changes in our mining plan through stoppages or increased costs because of the necessity of obtaining such rights.

In addition, the utility industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for our coal. It is possible that new environmental legislation or regulations may be adopted, or that existing laws or regulations may be differently interpreted or more stringently enforced, any of which could have a significant impact on our mining operations or our customers' ability to use coal. Any switching of fuel sources away from coal, closure of existing coal-fired power plants, or reduced construction of new plants could have adverse effects on demand for and prices received for our coal.

We may be unable to obtain, maintain or renew permits necessary for our operations, which would materially adversely affect our production, cash flow and profitability.

Mining companies must regularly obtain, maintain or renew a number of permits that impose strict requirements on various environmental and operational matters in connection with coal mining. These include permits issued by various federal, state and local agencies and regulatory bodies. The permitting rules, and the interpretations of these rules, are complex, change frequently, and are often subject to discretionary interpretations by the regulators, all of which may make compliance more difficult or impractical, and may possibly preclude the continuance of ongoing mine development or operations or the development of future mining operations. The public, including non-governmental organizations, anti-mining groups and individuals, have certain statutory rights to comment upon and submit objections to requested permits and environmental impact statements prepared in connection with applicable regulatory processes, and otherwise engage in the permitting process, including bringing citizens' claims to challenge the issuance or renewal of permits, the validity of environmental impact statements or performance of mining activities. Accordingly, required permits may not be issued or renewed in a timely fashion or issued or renewed at all, or permits issued or renewed may not be maintained, may be challenged or may be conditioned in a manner that may restrict our ability to efficiently and economically conduct our mining activities, any of which would materially reduce our production, cash flow, and profitability as well as our ability to pay distributions to our unitholders.

New legislation or administrative regulations or new judicial interpretations or administrative enforcement of existing laws and regulations, including proposals related to the protection of the environment and to human health and safety that would further regulate and tax the coal industry may also require us to change operations significantly or incur increased costs. For example, the EPA

recently released its finalized revisions to its definition of "waters of the United States," which could result in new or expanded permitting requirements and may delay and add costs to the process for obtaining these permits. Such changes could have a material adverse effect on our financial condition and results of operations as well as our ability to pay distributions to our unitholders. Please read "Environmental and Other Regulatory Matters."

Review of BLM leasing decisions under NEPA may extend the time and/or increase the costs for obtaining necessary governmental approvals associated with our lease applications, which could materially adversely affect our production, cash flow and profitability.

Substantially all of our current and planned activities and operations rely on mineral leases administered by the BLM. The BLM administers competitive coal leases both on a regional basis, where the BLM selects tracts within a region for competitive sale, and through the LBA process, where the public nominates a particular tract of coal for competitive sale. All current BLM leasing is done through the LBA process. Because both regional leases and LBA tracts require one or more governmental approvals, both leasing processes may trigger the requirements of NEPA, which requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment.

Compliance with NEPA can be time-consuming and may result in the imposition of mitigation measures that could affect the amount of coal that we are able to produce from mines on federal lands, and may require public comment. Whether the BLM has complied with NEPA is also subject to protest, appeal or litigation, which can delay or halt projects. For example, in June 2014, a federal court in Colorado rejected a NEPA analysis performed by the U.S. Forest Service and the BLM for various coal mine-related matters, including various lease modifications, specifically holding that the manner in which certain impacts associated with GHG emissions were analyzed was insufficient. This decision adds to the uncertainty surrounding the nature and extent of disclosure required by NEPA for climate change impacts associated with governmental actions. Recently, the Council on Environmental Quality published an updated Draft Guidance for federal agencies on "when and how" to consider and discuss the effects of GHG emissions in any analysis undertaken pursuant to NEPA, but it remains to be seen whether this guidance will provide meaningful certainty about the nature of the disclosures required under NEPA for climate change impacts associated with governmental actions. Recently, non-governmental organizations have filed objections with the BLM and U.S. Forest Service regarding the BLM's decision to offer the Greens Hollow tract for lease. These objections allege that the supplemental environmental impact statement prepared in connection with the issuance of the Greens Hollow lease fails to comply with NEPA for many reasons, including the failure to adequately address impacts associated with GHG emissions. Further, the leasing action related to the Flat Canyon tract by the BLM could also be challenged in the Department of Interior's Board of Land Appeals or in federal district court. The May 15, 2015 Notice of Lease Sale of the Flat Canyon tract prompted letters by several non-governmental organizations objecting to the lease sale on, among other things, environmental grounds. In another recent case, *WildEarth Guardians v. United States Office of Surface Mining, Reclamation and Enforcement*, the United States District Court for the District of Colorado identified several deficiencies in the NEPA compliance processes relating to approvals of two separate mining plan modifications for Colorado coal mines that had been issued in 2007 and 2009, respectively. The court gave the Office of Surface Mining 120 days to address these deficiencies before the previously-approved mining plans would be vacated. This decision demonstrates courts' willingness to assess NEPA compliance even where relevant approvals have been granted long ago and mining operations are underway. We cannot assure you that there will not be delays in our development plans or operations because of the NEPA review process. For these reasons, NEPA reviews may extend the time and/or increase the costs for obtaining necessary governmental approvals, which could negatively affect our production, cash flow and profitability.

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A change or disruption in our water supply, loss of water rights or interference with water rights owned by others in Utah could adversely affect our results of operations.

Our operations in Utah are heavily dependent upon our access to adequate supplies of water made available under water rights administered by the Utah Division of Water Rights (the "Division"). If we have difficulties obtaining adequate supplies of water due to availability, environmental, legal or other restrictions, or if our operations interfere with existing water rights owned by others, our operations and business may be adversely affected. The Division administers water rights by priority established by the date of application for the water right or the date of first use of the water whereby the water right with the earliest priority date in a source may divert and use its full supply before later priority water rights may divert and use any water. The water in the vicinity of the mines being operated in Utah is fully allocated to existing water rights, and no new water rights are being issued by the Division. Limited water rights are available for acquisition by purchase or lease and administrative change permitting a new use at the mines. There can be no assurance that applicable laws and regulations will not change in a manner that could have an adverse effect on our water rights and operations, or that we will not lose all or a portion of our water rights by abandonment or forfeiture. The physical supply of water needed to fully satisfy our water rights may vary from season to season and year to year and is dependent upon a number of factors including climatic conditions, upstream appropriators of water or other groundwater appropriators in the vicinity of the mines. Any failure of access to adequate water supplies provided under our water rights to support our current operations and any potential expansion would have a material adverse effect on our financial condition and results of operations.

Extensive governmental regulation pertaining to employee safety and health imposes significant costs on our mining operations and could materially adversely affect our results of operations.

Federal and state safety and health regulations in the coal mining industry are among the most comprehensive and pervasive systems for protection of employee safety and health affecting any U.S. industry. Compliance with these requirements imposes significant costs on us and can result in reduced productivity.

The possibility exists that new health and safety legislation, regulations and orders may be adopted that may materially adversely affect our mining operations. For example, in response to underground mine accidents of our competitors in the last decade, state and federal legislatures and regulatory authorities have increased scrutiny of mine safety matters and adopted more stringent requirements governing all forms of mining, including increased sanctions for and disclosure regarding non-compliance. In 2006, Congress enacted the MINER Act, which imposed additional obligations on all coal operators, including, among other matters:

- the development of new emergency response plans;
- ensuring the availability of mine rescue teams;
- prompt notification to federal authorities of incidents that pose a reasonable risk of death; and
- increased penalties for violations of the applicable federal laws and regulations.

Various states also have enacted new laws and regulations addressing many of these same subjects.

Federal and state health and safety authorities inspect our operations, and we anticipate a significant increase in the frequency and scope of these inspections. In recent years, federal authorities have also conducted special inspections of coal mines for, among other safety concerns, the accumulation of coal dust and the proper ventilation of gases such as methane. In addition, the federal government has announced that it is considering changes to mine safety rules and regulations. For example, MSHA recently finalized a new rule limiting miners' exposure to respirable coal dust. The first phase of the rule went into effect as of August 1, 2014, and requires, among other things, single shift sampling to determine noncompliance and corrective action to remedy any excessive levels of dust. The next phase of the rule takes effect February 1, 2016, and requires increased sampling frequency

and the use of continuous personal dust monitors. This and other future mine safety rules could potentially result in or require significant expenditures, as well as additional safety training and planning, enhanced safety equipment, more frequent mine inspections, stricter enforcement practices and enhanced reporting requirements.

We must compensate employees for work-related injuries. If we do not make adequate provisions for our workers' compensation liabilities, we may be forced to pay higher amounts for these liabilities in the future, which may add to our compliance costs and adversely affect our operating results. Under the Black Lung Benefits Revenue Act of 1977 and Black Lung Benefits Reform Act of 1977, as amended in 1981, each coal mine operator must secure payment of federal black lung benefits to claimants who are current and former employees and contribute to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry before July 1973. The trust fund is funded by an excise tax on coal production of up to $1.10 per ton for underground coal sold domestically, not to exceed 4.4% of the gross sales price. For the years ended December 31, 2014 and 2013, we recognized approximately $9.5 million and $10.0 million, respectively, of expense related to this tax. If this tax increases, or if we could no longer pass it on to the purchasers of our coal under our coal supply agreements, our operating costs could be increased and our results could be materially adversely effected. If new laws or regulations increase the number and award size of claims, it could materially adversely harm our business. Please read "Environmental and Other Regulatory Matters." In addition, the erosion through tort liability of the protections we are currently provided by workers' compensation laws could increase our liability for work-related injuries and have a material adverse effect on our results of operations, cash flows and financial condition as well as our ability to pay distributions to our unitholders.

Finally, as a public company, we will be subject to the Dodd-Frank Wall Street Reform and Consumer Protection Act provisions requiring disclosure in our periodic and other reports filed with the SEC regarding specified health and safety violations, orders and citations, related assessments and legal actions and mining-related fatalities.

Federal or state regulatory agencies have the authority to order certain of our mines to be temporarily or permanently closed under certain circumstances, which could materially adversely affect our ability to meet our customers' demands.

Federal or state regulatory agencies, including MSHA and the Utah Department of Natural Resources Division of Oil, Gas, and Mining, have the authority under certain circumstances following significant health, safety or environmental incidents or pursuant to permitting authority to temporarily or permanently close one or more of our mines. If this occurred, we may be required to incur capital expenditures to re-open the mine. In the event that these agencies cause us to close one or more of our mines, our coal supply agreements generally permit us to issue force majeure notices which suspend our obligations to deliver coal under such agreements. However, our customers may challenge our issuances of force majeure notices in connection with these closures. If these challenges are successful, we may have to purchase coal from third-party sources, if available, to fulfill these obligations, incur capital expenditures to re-open the mine or negotiate settlements with the customers, which may include price reductions, the reduction of commitments or the extension of time for delivery or termination of such customers' agreements. Any of these actions could have a material adverse effect on our results of operations, cash flows and financial condition as well as our ability to pay distributions to our unitholders.

Our operations may impact the environment or cause exposure to hazardous substances, and our properties may have environmental contamination, which could result in material liabilities to us.

Certain of our current and historical coal mining operations may use or may have used hazardous and other regulated materials and may have generated hazardous wastes. We may be subject to claims under federal and state statutes or common law doctrines for penalties, toxic torts and other damages,

as well as for natural resource damages and for the investigation and remediation of soil, surface water, groundwater, and other media under laws such as the CERCLA, commonly known as Superfund, or the CWA. Such claims may arise, for example, out of current, former or threatened conditions at sites that we currently own or operate as well as at sites that we and companies we acquired owned or operated in the past, or sent waste to for treatment or disposal, and at contaminated sites that have always been owned or operated by third parties. Liability may be strict, joint and several, so that we, regardless of whether we caused contamination, may be held responsible for more than our share of the contamination or other damages, or even for the entire share. These and other similar unforeseen impacts that our operations may have on the environment, as well as exposures to regulated materials or wastes associated with our operations, could result in costs and liabilities that could have a material adverse effect on our results of operations, cash flows and financial condition as well as our ability to pay distributions to our unitholders.

New developments in the regulation of GHG emissions and coal ash could materially adversely affect our customers' demand for coal and our results of operations, cash flows and financial condition.

Coal-fired power plants produce carbon dioxide and other GHGs as a by-product of their operations. GHG emissions have received increasing scrutiny from local, state, federal and international government bodies. Future regulation of GHGs could occur pursuant to U.S. treaty obligations or statutory or regulatory change. The EPA and other regulators are using existing laws, including the federal Clean Air Act, to limit emissions of carbon dioxide and other GHGs from major sources, including coal-fired power plants that may require the use of "best available control technology." For example, the EPA has issued regulations restricting GHG emissions from any new U.S. power plants, and from any existing U.S. power plants that undergo major modifications that increase their GHG emissions. The EPA also recently proposed new source performance standards for GHG emissions for new coal and oil-fired power plants, which could require partial carbon capture and sequestration. In addition, in June 2013, President Obama announced additional initiatives intended to reduce GHG emissions globally, including curtailing U.S. government support for public financing of new coal-fired power plants overseas and promoting fuel switching from coal to natural gas or renewable energy sources. Global treaties are also being considered that place restrictions on carbon dioxide and other GHG emissions, though the United States has not assumed any mandatory reduction requirements to date. On June 2, 2014, the EPA further proposed new regulations limiting carbon dioxide emissions from existing power generation facilities. Under this proposal, nationwide carbon dioxide emissions would be reduced by 30% from 2005 levels by 2030 with a flexible interim goal. The current schedule calls for the final rule to be issued by mid-summer 2015, with the emission reductions scheduled to commence in 2020. The permitting of new coal-fired power plants has recently been contested by state regulators and environmental organizations over concerns related to GHG emissions from the new plants. In addition, state and regional climate change initiatives to regulate GHG emissions, such as the Regional Greenhouse Gas Initiative of certain northeastern and mid-Atlantic states, the Western Climate Initiative, the Midwestern Greenhouse Gas Reduction Accord and the California Global Warming Solutions Act, either have already taken effect or may take effect before federal action. Further, governmental agencies have been providing grants or other financial incentives to entities developing or selling alternative energy sources with lower levels of GHG emissions, which may lead to more competition from those entities. There have also been several public nuisance lawsuits brought against power, coal, oil and natural gas companies alleging that their operations are contributing to climate change. The plaintiffs are seeking various remedies, including punitive and compensatory damages and injunctive relief. While the U.S. Supreme Court recently determined that such claims cannot be pursued under federal law, plaintiffs may seek to proceed under state common law.

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A well-publicized failure in December 2008 of a coal ash slurry impoundment maintained by the Tennessee Valley Authority used to store ash from its coal burning power plants has led to new legislative and regulatory scrutiny and proposals that, if enacted, may impose significant obligations on us or our customers. For example, in December 2014, the EPA finalized regulations to address the management of coal ash as a solid waste under RCRA. These new regulatory obligations may result in costs and potential liability for handling coal ash for our utility customers and for us if we were to use coal ash for reclamation, or store or dispose of coal ash for any of our utility customers. Please read "Environmental and Other Regulatory Matters" for additional details.

Extensive environmental regulations, including existing and potential future regulatory requirements relating to air emissions, affect our customers and could reduce the demand for coal as a fuel source and cause coal prices and sales of our coal to materially decline.

The operations of our customers are subject to extensive environmental regulation particularly with respect to air emissions. For example, the federal Clean Air Act and similar state and local laws extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury, and other compounds emitted into the air from electric power plants, which are the largest end-users of our coal. A series of more stringent requirements relating to particulate matter, ozone, haze, mercury, sulfur dioxide, nitrogen oxide and other air pollutants will, or are expected to become effective in coming years. In addition, concerted conservation efforts that result in reduced electricity consumption could cause coal prices and sales of our coal to materially decline.

More stringent air emissions limitations may require significant emissions control expenditures for many coal-fired power plants and could have the effect of making coal-fired power plants less profitable. As a result, some power plants may switch to other fuels that generate less of these emissions or they may close. Any switching of fuel sources away from coal, closure of existing coal-fired power plants, or reduced construction of new plants could have a material adverse effect on demand for and prices received for our coal. Please read "Environmental and Other Regulatory Matters."

Risks Inherent in an Investment in Us

Our sponsor owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including our sponsor, have conflicts of interest with us and limited duties, and they may favor their own interests to the detriment of us and our unitholders.

Following this offering, our sponsor will own and control our general partner and will appoint all of the directors of our general partner. Although our general partner has a duty to manage us in a manner that it believes is not adverse to our interest, the executive officers and directors of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to our sponsor. Therefore, conflicts of interest may arise between our sponsor or any of its affiliates, including our general partner, on the one hand, and us or any of our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our common unitholders. These conflicts include the following situations, among others:

- our general partner is allowed to take into account the interests of parties other than us, such as our sponsor, in exercising certain rights under our partnership agreement;
- neither our partnership agreement nor any other agreement requires our sponsor to pursue a business strategy that favors us;
- our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limits our general partner's

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liabilities and restricts the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty;

- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the level of cash reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner determines the amount and timing of any cash expenditure and whether an expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. Please read "How We Make Distributions To Our Partners—Operating Surplus and Capital Surplus—Capital Expenditures" for a discussion on when a capital expenditure constitutes a maintenance capital expenditure or an expansion capital expenditure. This determination can affect the amount of cash from operating surplus that is distributed to our unitholders which, in turn, may affect the ability of the subordinated units to convert. Please read "How We Make Distributions To Our Partners —Subordination Period";
- our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period;
- our partnership agreement permits us to distribute up to $ million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated units or the incentive distribution rights;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with its affiliates on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner may exercise its right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- our general partner controls the enforcement of obligations that it and its affiliates owe to us;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of the board of directors of our general partner or the unitholders. This election may result in lower distributions to the common unitholders in certain situations.

In addition, we may compete directly with our sponsor and entities in which it has an interest for acquisition opportunities and potentially will compete with these entities for new business or extensions of the existing services provided by us. Please read "—Our sponsor and other affiliates of our general partner may compete with us" and "Conflicts of Interest and Fiduciary Duties."

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The board of directors of our general partner may modify or revoke our cash distribution policy at any time at its discretion. Our partnership agreement does not require us to pay any distributions at all.

The board of directors of our general partner will adopt a cash distribution policy pursuant to which we intend to distribute quarterly at least $ per unit on all of our units to the extent we have sufficient cash after the establishment of cash reserves and the payment of our expenses, including payments to our general partner and its affiliates. However, the board of directors of our general partner may change such policy at any time at its discretion and could elect not to pay distributions for one or more quarters. Please read "Cash Distribution Policy and Restrictions on Distributions."

In addition, our partnership agreement does not require us to pay any distributions at all. Accordingly, investors are cautioned not to place undue reliance on the permanence of such a policy in making an investment decision. Any modification or revocation of our cash distribution policy could substantially reduce or eliminate the amount of distributions to our unitholders. The amount of distributions we make, if any, and the decision to make any distribution at all will be determined by the board of directors of our general partner, whose interests may differ from those of our common unitholders. Our general partner has limited duties to our unitholders, which may permit it to favor its own interests or the interests of our sponsor to the detriment of our common unitholders.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements between us and third parties so that the counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner's duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

We expect to distribute a significant portion of our cash available for distribution to our partners, which could limit our ability to grow and make acquisitions.

We plan to distribute most of our cash available for distribution, which may cause our growth to proceed at a slower pace than that of businesses that reinvest their cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which in turn, may impact the cash that we have available to distribute to our unitholders.

Our right of first refusal to acquire certain of our sponsor's assets is subject to risks and uncertainties, and ultimately we may not acquire any of those assets.

Our omnibus agreement will provide us with a right of first refusal to acquire certain of our sponsor's coal and terminal properties and our agreement with Bowie Refined Coal, LLC, an affiliate of our sponsor, will provide us with a right of first refusal to acquire certain refined coal projects. The consummation and timing of any future acquisitions of such assets will depend upon, among other things, our sponsor's or its affiliate's willingness to offer such assets for sale, our ability to negotiate acceptable customer contracts and other agreements with respect to such assets and our ability to

obtain financing on acceptable terms. We can offer no assurance that we will be able to successfully consummate any future acquisitions pursuant to our rights under these agreements and neither our sponsor nor its affiliate is under any obligation to sell any assets that would be subject to our right of first refusal. For these or a variety of other reasons, we may decide not to exercise our right of first refusal when any assets are offered for sale, and our decision will not be subject to unitholder approval. Please read "Certain Relationships and Related Party Transactions—Agreements with Affiliates in Connection with the Transactions."

Our partnership agreement replaces our general partner's fiduciary duties to unitholders.

Our partnership agreement contains provisions that eliminate and replace the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its affiliates;
- whether to exercise its call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the board of directors of our general partner;
- how to exercise its voting rights with respect to the units it owns;
- whether to exercise its registration rights;
- whether to elect to reset target distribution levels; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a unitholder is treated as having consented to the provisions in the partnership agreement, including the provisions discussed above. Please read "Conflicts of Interest and Fiduciary Duties—Fiduciary Duties."

Our partnership agreement restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement provides that:

- whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is generally required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any higher standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;
- our general partner and its officers and directors will not be liable for monetary damages or otherwise to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that such losses or liabilities were the result of conduct in which our general partner or its officers or directors engaged in bad faith, meaning that they believed that the decision was

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adverse to the interest of the partnership or, with respect to any criminal conduct, with knowledge that such conduct was unlawful; and

- our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our limited partners if a transaction with an affiliate or the resolution of a conflict of interest is:

  (1) approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval; or

  (2) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, other than one where our general partner is permitted to act in its sole discretion, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee then it will be presumed that, in making its decision, taking any action or failing to act, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Please read "Conflicts of Interest and Fiduciary Duties."

Our sponsor and other affiliates of our general partner may compete with us.

Our partnership agreement provides that our general partner will be restricted from engaging in any business activities other than acting as our general partner, engaging in activities incidental to its ownership interest in us and providing management, advisory, and administrative services to its affiliates or to other persons. However, affiliates of our general partner, including our sponsor, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. In addition, our sponsor may compete with us for investment opportunities and may own an interest in entities that compete with us.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers and directors and our sponsor. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our unitholders. Please read "Conflicts of Interest and Fiduciary Duties."

The holder or holders of our incentive distribution rights may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to the incentive distribution rights, without the approval of the conflicts committee of our general partner's board of directors or the holders of our common units. This could result in lower distributions to holders of our common units.

The holder or holders of a majority of our incentive distribution rights (initially our general partner) have the right, at any time when there are no subordinated units outstanding and we have made cash distributions in excess of the highest then-applicable target distribution for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our cash distribution levels at the time of the exercise of the reset election. Following a reset election

by our general partner, the minimum quarterly distribution will be calculated equal to an amount equal to the prior cash distribution per common unit for the fiscal quarter immediately preceding the reset election (which amount we refer to as the "reset minimum quarterly distribution") and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution. If our general partner elects to reset the target distribution levels, it will be entitled to receive a number of common units equal to the number of common units that would have entitled the holder to an aggregate quarterly cash distribution for the quarter prior to the reset election equal to the distribution on the incentive distribution rights for the quarter prior to the reset election.

We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per unit without such conversion. However, our general partner may transfer the incentive distribution rights at any time. It is possible that our general partner or a transferee could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when the holders of the incentive distribution rights expect that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, the holders of the incentive distribution rights may be experiencing, or may expect to experience, declines in the cash distributions it receives related to the incentive distribution rights and may therefore desire to be issued our common units rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience reduction in the amount of cash distributions that they would have otherwise received had we not issued new common units to the holders of the incentive distribution rights in connection with resetting the target distribution levels. Please read "How We Make Distributions To Our Partners—Incentive Distribution Rights—Incentive Distribution Right Holders' Right to Reset Incentive Distribution Levels."

Cost and expense reimbursements, which will be determined by our general partner in its sole discretion, and fees due to our general partner and our sponsor for services provided will reduce the amount of cash available to pay distributions to our unitholders.

Under our partnership agreement, we are required to reimburse our general partner for all expenses it incurs and payments it makes on our behalf. Our partnership agreement does not set a limit on the amount of expenses for which our general partner may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our general partner is entitled to determine the expenses that are allocable to us. We also expect to enter into an omnibus agreement with our sponsor, pursuant to which we will reimburse our sponsor on a cost-of-services basis for certain services performed on our behalf. The reimbursement of expenses and payment of fees, if any, to our general partner and our sponsor will reduce the amount of cash available to pay distributions to our unitholders. We expect that we will reimburse our sponsor and our general partner approximately $15.7 million in total for services performed under the partnership agreement and the omnibus agreement during the twelve months ending June 30, 2016.

Our partnership agreement includes exclusive forum, venue and jurisdiction provisions. By purchasing a common unit, a limited partner is irrevocably consenting to these provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of Delaware courts.

Our partnership agreement is governed by Delaware law. Our partnership agreement includes exclusive forum, venue and jurisdiction provisions designating Delaware courts as the exclusive venue for most claims, suits, actions and proceedings involving us or our officers, directors and employees. Please read "The Partnership Agreement—Applicable Law; Forum, Venue and Jurisdiction." If a

dispute were to arise between a limited partner and us or our officers, directors or employees, the limited partner may be required to pursue its legal remedies in Delaware which may be an inconvenient or distant location and which is considered to be a more corporate-friendly environment.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which our common units will trade.

Compared to the holders of common stock in a corporation, unitholders have limited voting rights and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner, including the independent directors, is chosen entirely by our sponsor, as a result of it owning our general partner, and not by our unitholders. Please read "Management—Management of Bowie Resource Partners LP" and "Certain Relationships and Related Party Transactions." Unlike publicly traded corporations, we will not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without its consent.

If our unitholders are dissatisfied with the performance of our general partner, they will have limited ability to remove our general partner. Unitholders initially will be unable to remove our general partner without its consent because our general partner and its affiliates will own sufficient units upon the completion of this offering to be able to prevent its removal. The vote of the holders of at least $66^{2}/_{3}$% of all outstanding common and subordinated units voting together as a single class is required to remove our general partner. Following the closing of this offering, our sponsor will own an aggregate of % of our common and subordinated units (or % of our common and subordinated units, if the underwriters exercise their option to purchase additional common units in full).

In addition, any vote to remove our general partner during the subordination period must provide for the election of a successor general partner by the holders of a majority of the common units and a majority of the subordinated units, voting as separate classes. This will provide our sponsor the ability to prevent the removal of our general partner.

Unitholders will experience immediate and substantial dilution of $ per common unit.

The assumed initial public offering price of $ per common unit (the mid-point of the price range set forth on the cover page of this prospectus) exceeds our pro forma net tangible book value of $ per common unit. Based on the assumed initial public offering price of $ per common unit, unitholders will incur immediate and substantial dilution of $ per common unit. This dilution results primarily because the assets contributed to us by affiliates of our general partner are recorded at their historical cost in accordance with GAAP, and not their fair value. Please read "Dilution."

Our general partner interest or the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party without the consent of our unitholders. Furthermore, our partnership agreement does not restrict the ability of the owner of our general partner to transfer its membership interests in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and

executive officers of our general partner with its own designees and thereby exert significant control over the decisions taken by the board of directors and executive officers of our general partner. This effectively permits a "change of control" without the vote or consent of the unitholders.

The incentive distribution rights may be transferred to a third party without unitholder consent.

Our general partner may transfer the incentive distribution rights to a third party at any time without the consent of our unitholders. If our general partner transfers the incentive distribution rights to a third party, our general partner would not have the same incentive to grow our partnership and increase quarterly distributions to our unitholders over time. For example, a transfer of incentive distribution rights by our general partner could reduce the likelihood of our sponsor accepting offers made by us relating to assets owned by our sponsor, as it would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

Our general partner has a call right that may require unitholders to sell their common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price equal to the greater of (1) the average of the daily closing price of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (2) the highest per-unit price paid by our general partner or any of its affiliates for common units during the 90-day period preceding the date such notice is first mailed. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Unitholders may also incur a tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from causing us to issue additional common units and then exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Securities Exchange Act of 1934 (the "Exchange Act"). Upon consummation of this offering, and assuming no exercise of the underwriters' option to purchase additional common units, our sponsor will own an aggregate of % of our common and subordinated units. At the end of the subordination period, assuming no additional issuances of units (other than upon the conversion of the subordinated units), our sponsor will own % of our common units. For additional information about the limited call right, please read "The Partnership Agreement—Limited Call Right."

We may issue an unlimited number of additional partnership interests without unitholder approval, which would dilute existing unitholder ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests we may issue at any time without the approval of our unitholders. The issuance of additional common units or other equity interests of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;

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- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

There are no limitations in our partnership agreement on our ability to issue units ranking senior to the common units.

In accordance with Delaware law and the provisions of our partnership agreement, we may issue additional partnership interests that are senior to the common units in right of distribution, liquidation and voting. The issuance by us of units of senior rank may (1) reduce or eliminate the amount of cash available for distribution to our common unitholders; (2) diminish the relative voting strength of the total common units outstanding as a class; or (3) subordinate the claims of the common unitholders to our assets in the event of our liquidation.

The market price of our common units could be adversely affected by sales of substantial amounts of our common units in the public or private markets, including sales by our sponsor or other large holders.

After this offering, we will have common units and subordinated units outstanding, which includes the common units we are selling in this offering that may be resold in the public market immediately. All of the subordinated units will convert into common units on a one-for-one basis at the end of the subordination period. The common units (if the underwriters do not exercise their option to purchase additional common units) that are issued to our sponsor will be subject to resale restrictions under a 180-day lock-up agreement with the underwriters. Each of the lock-up agreements with the underwriters may be waived in the discretion of certain of the underwriters. Sales by our sponsor or other large holders of a substantial number of our common units in the public markets following this offering, or the perception that such sales might occur, could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities. In addition, we have agreed to provide registration rights to our sponsor. Under our partnership agreement, our general partner and its affiliates have registration rights relating to the offer and sale of any units that they hold. Alternatively, we may be required to undertake a future public or private offering of common units and use the net proceeds from such offering to redeem an equal number of common units held by our sponsor. Please read "Units Eligible for Future Sale."

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our partnership agreement restricts unitholders' voting rights by providing that any units held by a person or group that owns 20% or more of any class of units then outstanding, other than our general partner and its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter.

There is no existing market for our common units and a trading market that will provide you with adequate liquidity may not develop. The price of our common units may fluctuate significantly, and unitholders could lose all or part of their investment.

Prior to this offering, there has been no public market for the common units. After this offering, there will be only publicly traded common units. We do not know the extent to which investor interest will lead to the development of a trading market or how liquid that market might be. Unitholders may not be able to resell their common units at or above the initial public offering price. Additionally, the lack of liquidity may result in wide bid-ask spreads, contribute to significant

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fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

The initial public offering price for our common units will be determined by negotiations between us and the representatives of the underwriters and may not be indicative of the market price of the common units that will prevail in the trading market. The market price of our common units may decline below the initial public offering price. The market price of our common units may also be influenced by many factors, some of which are beyond our control, including:

- our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units after this offering or changes in financial estimates by analysts;
- future sales of our common units; and
- the other factors described in these "Risk Factors."

Unitholders may have liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act"), we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements that apply to other public companies, including those relating to auditing standards and disclosure about our executive compensation.

The JOBS Act contains provisions that, among other things, relax certain reporting requirements for "emerging growth companies," including certain requirements relating to auditing standards and compensation disclosure. We are classified as an emerging growth company. For as long as we are an emerging growth company, which may be up to five full fiscal years, unlike other public companies, we will not be required to, among other things, (1) provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002, (2) comply with any new requirements adopted by the PCAOB requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (3) comply with any new audit rules adopted by the PCAOB after April 5, 2012 unless the SEC determines otherwise or (4) provide certain disclosure regarding executive compensation required of larger public companies.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders

could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our units.

The NYSE does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

We intend to apply to list our common units on the NYSE. Because we will be a publicly traded partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders will not have the same protections afforded to stockholders of certain corporations that are subject to all of the NYSE's corporate governance requirements. Please read "Management—Management of Bowie Resource Partners LP."

We will incur increased costs as a result of being a publicly traded partnership.

We have no history operating as a publicly traded partnership. As a publicly traded partnership, we will incur significant legal, accounting and other expenses that we did not incur prior to this offering. In addition, the Sarbanes-Oxley Act of 2002, as well as rules implemented by the SEC and the NYSE, require publicly traded entities to adopt various corporate governance practices that will further increase our costs. The amount of our expenses or reserves for expenses, including the costs of being a publicly traded partnership, will reduce the amount of cash we have for distribution to our unitholders. As a result, the amount of cash we have available for distribution to our unitholders will be affected by the costs associated with being a public company.

Prior to this offering, we have not filed reports with the SEC. Following this offering, we will become subject to the public reporting requirements of the Exchange Act. We expect these rules and regulations to increase certain of our legal and financial compliance costs and to make activities more time-consuming and costly. For example, as a result of becoming a publicly traded company, we are required to have at least three independent directors, create an audit committee and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting. In addition, we will incur additional costs associated with our SEC reporting requirements.

We also expect to incur significant expense in order to obtain director and officer liability insurance. Because of the limitations in coverage for directors, it may be more difficult for us to attract and retain qualified persons to serve on the board of directors of our general partner or as executive officers.

We estimate that we will incur approximately $ million of incremental costs per year associated with being a publicly traded partnership; however, it is possible that our actual incremental costs of being a publicly traded partnership will be higher than we currently estimate.

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Unitholders who are not "Eligible Holders" will not be entitled to receive distributions on or allocations of income or loss on their common units, and their common units will be subject to redemption.

In order to comply with U.S. laws with respect to the ownership of interests in mineral leases on federal lands, we will adopt certain requirements regarding those investors who may own our common units. As used herein, an Eligible Holder means a person or entity qualified to hold an interest in mineral leases on federal lands. As of the date hereof, Eligible Holder means: (1) a citizen of the United States; (2) a corporation organized under the laws of the United States or of any state thereof; or (3) an association of United States citizens, such as a partnership or limited liability company, organized under the laws of the United States or of any state thereof, but only if this association does not have any direct or indirect foreign ownership, other than foreign ownership of stock in a parent corporation organized under the laws of the United States or of any state thereof. For the avoidance of doubt, onshore mineral leases or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding or control in a corporation organized under the laws of the United States or of any state thereof and only for so long as the alien is not from a country that the United States federal government regards as denying similar privileges to citizens or corporations of the United States. Common unitholders who are not persons or entities who meet the requirements to be an Eligible Holder will not be entitled to receive distributions or allocations of income and loss on their units and they run the risk of having their units redeemed by us at the lower of their purchase price cost or the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner.

Tax Risks to Common Unitholders

In addition to reading the following risk factors, please read "Material U.S. Federal Income Tax Consequences" for a more complete discussion of the expected material federal income tax consequences of owning and disposing of common units.

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution could be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us. Despite the fact that we are organized as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe, based upon our current operations, that we will be so treated, a change in our business, a change in current law or a change in the interpretation of current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a

corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. For example, President Obama's proposed fiscal year 2015 budget (the "2015 Budget Proposal") would eliminate the qualifying income exception to the treatment of publicly traded partnerships as corporations, upon which we rely for our treatment as a partnership for U.S. federal income tax purposes, for partnerships with qualifying income or gains from fossil fuels, including coal, beginning in 2021. Any modification to the federal income tax laws may be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for federal income tax purposes. Please read "Material U.S. Federal Income Tax Consequences—Taxation of the Partnership—Partnership Status." We are unable to predict whether these changes, or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

You will be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, you will be required to pay federal income taxes and, in some cases, state and local income taxes on your share of our taxable income whether or not you receive cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from that income.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have constructively terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Immediately following this offering, our sponsor will own, directly or indirectly, more than 50% of the total interests in our capital and profits. Therefore, a transfer by our sponsor of all or a portion of its interests in us could result in a termination of us as a partnership for federal income tax purposes. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than the calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, after our termination we would be treated as a new partnership for federal income tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. Please read "Material U.S. Federal Income Tax Consequences—Disposition of Units—Constructive Termination" for a discussion of the consequences of our termination for federal income tax purposes.

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Tax gain or loss on the disposition of our common units could be more or less than expected.

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income result in a decrease in your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis in those units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture of depreciation and amortization deductions and certain other items. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale. Please read "Material U.S. Federal Income Tax Consequences—Disposition of Units—Recognition of Gain or Loss" for a further discussion of the foregoing.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investments in common units by tax-exempt entities, such as employee benefit plans and IRAs, and non-U.S. persons raise issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to you.

The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest by the IRS, and the outcome of any IRS contest, may materially adversely impact the market for our common units and the price at which they trade. Our costs of any contest by the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

We will treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we will adopt depreciation, amortization and depletion positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. Our counsel is unable to opine as to the validity of this approach. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns. Please read "Material U.S. Federal Income Tax Consequences—Tax Consequences of Unit Ownership—Section 754 Election" for a further discussion of the effect of the depreciation and amortization positions we will adopt.

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We will prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. Nonetheless, we will allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. The use of this proration method may not be permitted under existing Treasury Regulations, and although the U.S. Treasury Department issued proposed Treasury Regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we will adopt. Accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss, and deduction among our unitholders. Please read "Material U.S. Federal Income Tax Consequences—Disposition of Units—Allocations Between Transferors and Transferees."

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered as having disposed of those common units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder whose common units are the subject of a securities loan. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

Certain U.S. federal income tax preferences currently available with respect to coal exploration and development may be eliminated as a result of future legislation.

The 2015 Budget Proposal recommends elimination of certain key U.S. federal income tax preferences related to coal exploration and development. The 2015 Budget Proposal would (1) repeal expensing of exploration and development costs relating to coal, (2) repeal the percentage depletion allowance with respect to coal properties, (3) repeal capital gains treatment of coal royalties and (4) repeal the domestic manufacturing deduction for the production of coal. The passage of any legislation as a result of the 2015 Budget Proposal or any other similar changes in U.S. federal income tax laws could eliminate or defer certain tax deductions that are currently available with respect to coal exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units.

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You will likely be subject to state and local taxes and return filing requirements in states where you do not live as a result of investing in our common units.

In addition to federal income taxes, you will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if you do not live in any of those jurisdictions. We will initially own assets and conduct business in Utah, Kentucky and Colorado, each of which currently imposes a personal income tax and also imposes income taxes on corporations and other entities. You may be required to file state and local income tax returns and pay state and local income taxes in these states. Further, you may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. It is your responsibility to file all U.S. federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our common units.

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USE OF PROCEEDS

We expect to receive approximately $ million of net proceeds from the sale of common units by us in this offering (based on an assumed initial offering price of $ per common unit, the mid-point of the price range set forth on the cover page of this prospectus), after deducting the estimated underwriting discounts and offering expenses. Assuming the Escrow Release Conditions have been satisfied, concurrently with the closing of this offering, we expect to receive approximately $ million of net proceeds from our offering of $ million aggregate principal amount of New Notes. We intend to use the net proceeds of this offering and our offering of the New Notes as follows: (i) $ million to make a cash distribution to our sponsor, in part as reimbursement for capital expenditures, (ii) $ million to repay the PacifiCorp Notes, (iii) $ million to repay the Prudential Notes and (iv) $ million for general partnership purposes.

If the underwriters exercise their option to purchase additional common units in full, the additional net proceeds to us would be approximately $ million (based on an assumed initial offering price of $ per common unit, the mid-point of the price range set forth on the cover page of this prospectus). The net proceeds from any exercise of such option will be used to make a cash distribution to our sponsor, in part as reimbursement for capital expenditures. If the underwriters do not exercise their option, we will issue such additional common units to our sponsor upon the expiration of the option for no additional consideration.

The Prudential Notes bear interest at LIBOR (subject to a floor of 1%) plus a margin of 5.1% and are due in various monthly installments through 2016. CFC may prepay the Prudential Notes, in whole but not in part, by paying a 2% prepayment fee, which steps down to 1% after October 11, 2015, and certain out-of-pocket expenses incurred by the lenders. The Prudential Notes will mature in October 2016.

The PacifiCorps Notes bear interest at 7% and mature on (i) December 31, 2019, with respect to the $10 million note issued by Hunter Prep Plant, LLC and (ii) the earlier of August 31, 2015 or the refinancing of the Senior Secured Credit Facilities, with respect to the $30 million note issued by Fossil Rock Resources, LLC.

We expect that a portion of the net proceeds distributed to our sponsor will be used by our sponsor to repay outstanding indebtedness under our sponsor's Senior Secured Credit Facilities (defined herein). We expect that Cedars, which is directly or indirectly owned or controlled by certain of our directors and director nominees, will receive $ million (or $ million if the underwriters exercise their option to purchase additional units) of the net proceeds from this offering as a result of the distribution by our sponsor of a portion of the proceeds it receives from us, and that our executive officers will receive an aggregate of $ million (or $ million if the underwriters exercise their option to purchase additional units) in connection with this offering from the cash distribution made to our sponsor pursuant to a sponsor-level bonus arrangement. Please read "Certain Relationships and Related Party Transactions—Agreements with Affiliates in Connection with the Transactions—Ownership Interests in our Sponsor and Arrangements with Management."

Affiliates of certain of the underwriters are lenders under our sponsor's Senior Secured Credit Facilities and, accordingly, may ultimately receive a portion of the net proceeds from the offering of our New Notes. Certain of the underwriters are also initial purchasers in connection with the New Notes offering. Please read "Underwriting."

An increase or decrease in the initial public offering price of $1.00 per common unit would cause the net proceeds that we will receive from the offering, after deducting the estimated underwriting discounts and offering expenses, to increase or decrease by approximately $ million.

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DILUTION

Dilution is the amount by which the offering price paid by the purchasers of common units sold in this offering will exceed the pro forma net tangible book value per common unit after the offering. On a pro forma basis as of March 31, 2015, after giving effect to the offering of common units and the application of the related net proceeds, our net tangible book value was $ million, or $ per common unit. Purchasers of common units in this offering will experience immediate and substantial dilution in net tangible book value per common unit for financial accounting purposes, as illustrated in the following table:

Initial public offering price per common unit	$
Net tangible book value per common unit before the offering(1)	
Increase in net tangible book value per common unit attributable to purchasers in the offering	
Less: Pro forma net tangible book value per common unit after the offering(2)	
Immediate dilution in tangible net book value per common unit to purchasers in the offering(3)(4)	$

(1) Determined by dividing the number of units (common units and subordinated units) to be issued to our general partner and its affiliates, including our sponsor, for the contribution of assets and liabilities to us) into the net tangible book value of the contributed assets and liabilities.

(2) Determined by dividing the total number of units to be outstanding after the offering (common units and subordinated units) into our pro forma net tangible book value, after giving effect to the application of the expected net proceeds of the offering.

(3) If the initial public offering price were to increase or decrease by $1.00 per common unit, then dilution in net tangible book value per common unit would equal $ and $, respectively.

(4) Assumes the underwriters' option to purchase additional common units from us is not exercised. If the underwriters' option to purchase additional common units from us is exercised in full, the immediate dilution in net tangible book value per common unit to purchasers in this offering will be $.

The following table sets forth the number of units that we will issue and the total consideration contributed to us by our general partner and its affiliates and by the purchasers of common units in this offering upon consummation of the transactions contemplated by this prospectus, assuming the underwriters' option to purchase additional common units is not exercised:

	Unit Acquired		Total Consideration	
	Number	Percent	Amount	Percent
		(in thousands)		
General partner and affiliates(a)(b)		%	$	%
Purchasers in the offering		%		%
Total		%	$	%

(a) The units issued to our general partner and its affiliates, including our sponsor, consist of common units and subordinated units.

(b) The assets contributed by our general partner and its affiliates were recorded at historical cost in accordance with GAAP. Book value of the consideration provided by our general partner and its

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affiliates, as of March 31, 2015, after giving effect to the application of the net proceeds of the offering, is as follows:

	(in thousands)
Book value of net assets contributed	$
Less: Reimbursement and distribution to our sponsor from net proceeds of the offering	
Total consideration	$

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CAPITALIZATION

The following table sets forth our cash and cash equivalents and our capitalization as of March 31, 2015:

- on an actual basis;
- on an as adjusted basis, after giving effect to the Utah Transaction; and
- on an as further adjusted basis, after giving effect to the IPO Reorganization, including this offering, the offering of the New Notes and the use of proceeds therefrom as described in "Use of Proceeds."

You should read this table together with "Prospectus Summary—IPO Reorganization and Partnership Structure," "Use of Proceeds," "Selected Historical and Pro Forma Financial and Other Data" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" and our financial statements, along with the notes thereto, included elsewhere in this prospectus.

	As of March 31, 2015		
	Actual	As Adjusted for the Utah Transaction	As Further Adjusted for the IPO Reorganization
	(in thousands)		
Cash and cash equivalents	$ —	$ —	$
Long-term debt(1):			
New Notes(2)	$ —	$ —	$
Revolving credit facility(3)	—	—	
Senior Secured Credit Facilities(4)	334,705	334,705	—
Quitchupah Road debt(5)	25,816	25,816	
Prudential Notes	10,767	10,767	
PacifiCorp Notes	—	40,000	—
IPFS notes(6)	7,190	7,190	
Total long-term debt	$ 378,478	$ 418,478	$
Partners' capital:			
Limited partners:			
Common unitholders—public	—	—	
Common unitholders—sponsor	—	—	
Subordinated unitholders—sponsor	—	—	
General partner interest	—	—	—
Total partners' capital	—	—	
Member's equity:			
Total member's equity	$ 8,066	$ 8,066	$ —
Total capitalization	$ 386,544	$ 426,544	$

(1) Includes current portion of long-term debt.

(2) Prior to this offering, Finance Corp. issued $ million aggregate principal amount of % senior secured notes due . From and after the satisfaction of the Escrow Release Conditions, which we expect to occur concurrently with the closing of this offering, the partnership will become a co-issuer of the New Notes and a party to the indenture governing the New Notes. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Long-Term Debt—Senior Secured Notes."

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(3) In connection with the closing of this offering, we expect to enter into a $ million revolving credit facility. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Long-Term Debt—Revolving Credit Facility."

(4) In connection with the closing of this offering, CFC will be released as a guarantor under our sponsor's Senior Secured Credit Facilities (defined herein), and the liens on the assets contributed to us and securing borrowings under these facilities will be released. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Long-Term Debt—Senior Secured Credit Facilities."

(5) In 2012, CFC financed the construction of a paved country road through County Municipal Financing Bonds with Sevier County, Utah. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Long-Term Debt—Quitchupah Road Debt."

(6) In February 2015, our sponsor financed annual insurance premiums for its insurance policies through notes payable to Imperial Premium Financing Specialists ("IPFS"). Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Long-Term Debt—Notes Payable to Imperial Premium Financing Specialists."

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CASH DISTRIBUTION POLICY AND RESTRICTIONS ON DISTRIBUTIONS

You should read the following discussion of our cash distribution policy in conjunction with the specific assumptions included in this section. In addition, you should read "Forward-Looking Statements" and "Risk Factors" for information regarding statements that do not relate strictly to historical or current facts and certain risks inherent in our business.

For additional information regarding our historical and pro forma combined results of operations, you should refer to the historical financial statements as well as our pro forma financial statements, included elsewhere in this prospectus.

General

Our Cash Distribution Policy

The board of directors of our general partner will adopt a cash distribution policy pursuant to which we intend to distribute at least the minimum quarterly distribution of $ per unit ($ per unit on an annualized basis) on all of our units to the extent we have sufficient cash after the establishment of cash reserves and the payment of our expenses, including payments to our general partner and its affiliates. We expect that if we are successful in executing our business strategy, we will grow our business in a steady and sustainable manner and distribute to our unitholders a portion of any increase in our cash available for distribution resulting from such growth. Our general partner has not caused us to establish any cash reserves, and does not have any specific types of expenses for which it intends to establish reserves. We expect our general partner may cause us to establish reserves for specific purposes, such as major capital expenditures or debt service payments, or may choose to generally reserve cash in the form of excess distribution coverage from time to time for the purpose of maintaining stability or growth in our quarterly distributions. In addition, our general partner may cause us to borrow amounts to fund distributions in quarters when we generate less cash than is necessary to sustain or grow our cash distributions per unit. Our cash distribution policy reflects a judgment that our unitholders will be better served by us distributing rather than retaining our cash available for distribution.

The board of directors of our general partner may change our distribution policy at any time and from time to time. Our partnership agreement does not require us to pay cash distributions on a quarterly or on any other basis.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy

There is no guarantee that we will make cash distributions to our unitholders. We do not have a legal or contractual obligation to pay distributions quarterly or on any other basis or at our minimum quarterly distribution rate or at any other rate. Our cash distribution policy is subject to certain restrictions and may be changed at any time. The reasons for such uncertainties in our stated cash distribution policy include the following factors:

- Our cash distribution policy will be subject to restrictions on distributions under our revolving credit facility and the indenture governing our New Notes, which contain financial tests and covenants that we must satisfy. These financial tests and covenants are described in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources." Should we be unable to satisfy these restrictions or if we are otherwise in default under our revolving credit facility or the indenture governing our New Notes, we will be prohibited from making cash distributions notwithstanding our stated cash distribution policy.

- Our general partner will have the authority to cause us to establish cash reserves for the prudent conduct of our business, including for future cash distributions to our unitholders, and the

establishment of or increase in those cash reserves could result in a reduction in cash distributions from levels we currently anticipate pursuant to our stated cash distribution policy. Our partnership agreement and our cash distribution policy do not set a limit on the amount of cash reserves that our general partner may cause us to establish.

- We are obligated under our partnership agreement to reimburse our general partner for all expenses it incurs and payments it makes on our behalf. Our partnership agreement does not set a limit on the amount of expenses for which our general partner may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us. We also expect to enter into an omnibus agreement with our sponsor, pursuant to which we will reimburse our sponsor on a cost-of-services basis for certain services performed on our behalf. The reimbursement of expenses and payment of fees, if any, to our general partner and our sponsor will reduce the amount of cash available to pay distributions to our unitholders. We expect that we will reimburse our sponsor and our general partner approximately $15.7 million in total for services performed under the partnership agreement and the omnibus agreement during the twelve months ending June 30, 2016.

- Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by our general partner.

- Under Section 17-607 of the Delaware Act, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets.

- We may lack sufficient cash to pay distributions to our unitholders due to cash flow shortfalls attributable to a number of operational, commercial or other factors as well as increases in our operating or general and administrative expenses, principal and interest payments on our outstanding debt, tax expenses, working capital requirements and anticipated cash needs.

- If we make distributions out of capital surplus, as opposed to operating surplus, any such distributions would constitute a return of capital and would result in a reduction in the minimum quarterly distribution and the target distribution levels. Please read "How We Make Distributions To Our Partners—Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels." We do not anticipate that we will make any distributions from capital surplus.

- Our ability to make distributions to our unitholders depends on the performance of our subsidiaries and their ability to distribute cash to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of present and future indebtedness, applicable state limited liability company laws and other laws and regulations.

Our Ability to Grow May Be Dependent on Our Ability to Access External Expansion Capital

We expect to generally distribute a significant percentage of our cash from operations to our unitholders on a quarterly basis, after the establishment of cash reserves and payment of our expenses. Therefore, our growth may not be as fast as businesses that reinvest most or all of their cash to expand ongoing operations. We expect that we will rely primarily upon external financing sources, including bank borrowings and issuances of debt and equity interests, to fund our expansion capital expenditures. To the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

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Relationship with Our Sponsor

All of our revenue and cash flow will be derived from our coal supply agreements and we will receive substantially all of our revenue and cash flow from our new coal supply agreement with our sponsor. As we expect to derive substantially all of our revenues through our sponsor for the foreseeable future, we will be subject to the risk of nonpayment or nonperformance by our sponsor under the coal supply agreement between us and our sponsor. Any event, whether related to our operations or otherwise, that materially adversely affects our sponsor's financial condition, results of operations or cash flows may adversely affect our ability to sustain or increase cash distributions to our unitholders.

Our sponsor is a privately owned company and has no obligations to disclose publicly financial or operating information. Accordingly, our unitholders will have little to no insight into our sponsor's ability to meet its obligations to us and to our customers, including its minimum coal purchase commitments under the coal supply agreement between us and our sponsor. Our ability to make minimum quarterly distributions on all outstanding units will be adversely affected if: (i) our sponsor does not fulfill its obligations to us or our customers; or (ii) our sponsor's obligations under our coal supply agreement are suspended, reduced or terminated and we are unable to generate additional revenues from third parties.

Our Minimum Quarterly Distribution

Upon completion of this offering, our partnership agreement will provide for a minimum quarterly distribution of $ per unit for each whole quarter, or $ per unit on an annualized basis. The payment of the full minimum quarterly distribution on all of the common units and subordinated units to be outstanding after completion of this offering would require us to have cash available for distribution of approximately $ million per quarter, or $ million per year. Our ability to make cash distributions at the minimum quarterly distribution rate will be subject to the factors described above under "—General—Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy."

The table below sets forth the amount of common units and subordinated units that will be outstanding immediately after this offering, assuming the underwriters do not exercise their option to purchase additional common units, and the cash available for distribution needed to pay the aggregate minimum quarterly distribution on all of such units for a single fiscal quarter and a four quarter period:

	No Exercise of Underwriters' Option to Purchase Additional Common Units			Full Exercise of Underwriters' Option to Purchase Additional Common Units		
		Aggregate Minimum Quarterly Distributions			Aggregate Minimum Quarterly Distributions	
	Number of Units	One Quarter	Annualized (Four Quarters)	Number of Units	One Quarter	Annualized (Four Quarters)
Publicly held common units		$	$		$	$
Common units held by our sponsor						
Subordinated units held by our sponsor						
Total		$	$		$	$

If the underwriters do not exercise their option to purchase additional common units, we will issue common units to our sponsor at the expiration of the option period. If and to the extent the underwriters exercise their option to purchase additional common units, the number of common units purchased by the underwriters pursuant to such exercise will be issued to the underwriters and the remainder, if any, will be issued to our sponsor. Any such units issued to our sponsor will be issued for no additional consideration. Accordingly, the exercise of the underwriters' option will not affect the

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total number of units outstanding or the amount of cash needed to pay the minimum quarterly distribution on all units. Please read "Underwriting."

Our general partner will initially hold the incentive distribution rights, which entitle the holder to increasing percentages, up to a maximum of 50.0%, of the cash we distribute in excess of $ per unit per quarter.

We expect to pay our distributions on or about the last day of each of February, May, August and November to holders of record on or about the 15th day of each such month. We will adjust the quarterly distribution for the period after the closing of this offering through , 2015 based on the actual length of the period.

Subordinated Units

Our sponsor will initially own all of our subordinated units. The principal difference between our common units and subordinated units is that for any quarter during the subordination period, holders of the subordinated units are not entitled to receive any distribution from operating surplus until the common units have received the minimum quarterly distribution from operating surplus for such quarter plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Subordinated units will not accrue arrearages. When the subordination period ends, all of the subordinated units will convert into an equal number of common units.

To the extent we do not pay the minimum quarterly distribution from operating surplus on our common units, our common unitholders will not be entitled to receive such payments in the future except during the subordination period. To the extent we have cash available for distribution from operating surplus in any future quarter during the subordination period in excess of the amount necessary to pay the minimum quarterly distribution to holders of our common units, we will use this excess cash to pay any distribution arrearages on common units related to prior quarters before any cash distribution is made to holders of subordinated units. Please read "How We Make Distributions To Our Partners—Subordination Period."

In the sections that follow, we present in detail the basis for our belief that we will be able to fully fund our minimum quarterly distribution of $ per common and subordinated unit each quarter for the twelve months ending June 30, 2016. In those sections, we present the following three tables:

- "Unaudited Pro Forma Cash Available for Distribution," in which we present our estimate of the amount of cash we would have had available for distribution for the year ended December 31, 2014 and the twelve months ended March 31, 2015, based on our historical financial statements, as adjusted to reflect incremental general and administrative expenses we expect we will incur as a publicly traded partnership.

- "Estimated Cash Available for Distribution," in which we demonstrate our anticipated ability to generate the cash available for distribution necessary for us to pay the minimum quarterly distribution on all units for the twelve months ending June 30, 2016.

- "Quarterly Forecast Information," in which we present our estimated cash available for distribution for the twelve months ending June 30, 2016 on a quarter-by-quarter basis for the forecast period.

Unaudited Pro Forma Cash Available for Distribution

As set forth in the table below, we believe that our pro forma cash available for distribution for the year ended December 31, 2014 and the twelve months ended March 31, 2015, if we had completed this offering and the IPO Reorganization described under "Prospectus Summary—IPO Reorganization

and Partnership Structure" on January 1, 2014, in each case, would not have been sufficient to pay the full minimum quarterly distribution on all of our common and subordinated units during that period.

Unaudited pro forma cash available for distribution includes incremental general and administrative expenses that we expect we will incur as a publicly traded partnership, including costs associated with SEC and Sarbanes-Oxley reporting requirements, annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and director compensation.

Our unaudited pro forma condensed consolidated financial statements, upon which our unaudited pro forma cash available for distribution is based, do not purport to present our results of operations had the IPO Reorganization actually been completed as of the date indicated. Furthermore, cash available for distribution is a cash accounting concept, while our combined financial statements have been prepared on an accrual basis. We derived the amounts of pro forma cash available for distribution stated above in the manner described in the table below. As a result, the amount of pro forma cash available for distribution should only be viewed as a general indication of the amount of cash available for distribution that we might have generated had we been formed and completed the transactions contemplated in this prospectus in earlier periods.

Our pro forma condensed consolidated financial statements are derived from the historical financial statements of CFC, included elsewhere in this prospectus. Our pro forma condensed consolidated financial statements should be read together with "Selected Historical and Pro Forma Financial and Other Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical financial statements of CFC included elsewhere in this prospectus.

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	Year Ended December 31, 2014	Twelve Months Ended March 31, 2015
	(in thousands, except per unit and per ton data)	
Operating Data:		
Tons produced		
Tons sold		
Coal sales realized per ton(1)	$	$
Direct mining costs per ton(2)	$	$
Financial Data:		
Coal sales	$	$
Other revenues, net		
Costs and expenses:		
Cost of coal sales, exclusive of items shown separately below		
Transportation		
Depreciation, depletion and amortization		
Accretion on asset retirement obligations		
Selling, general and administrative		
Amortization of acquired sales contracts, net		
Operating income	$	$
Other expenses:		
Interest expense and related financing costs		
Loss (gain) on sale of assets		
Other		
Pro forma net income	$	$
Adjustments to reconcile to pro forma EBITDA:		
Add:		
Depreciation, depletion and amortization		
Amortization of acquired sales contracts, net		
Interest expense and related financing costs		
Pro forma EBITDA(3)	$	$
Adjustments to reconcile to pro forma Adjusted EBITDA:		
Add:		
Accretion on asset retirement obligations		
Loss (gain) on sale of assets		
Other		
Pro forma Adjusted EBITDA(3)	$	$
Adjustments to reconcile to pro forma cash available for distribution:		
Add:		
Net proceeds from this offering or borrowings to fund capital expenditures(4)		
Less:		
Incremental general and administrative expense(5)		
Cash interest expense		
Expansion capital expenditures		
Actual maintenance expenditures		
Pro forma cash available for distribution	$	$
Minimum quarterly distribution per unit (annualized)	$	$
Distributions (annualized):		
Distributions to common unitholders—public	$	$
Distributions to common unitholders—sponsor		
Distributions to subordinated unitholders—sponsor		
Total distributions	$	$
Excess (shortfall)	$	$

(1) Coal sales realized per ton is defined as coal sales divided by tons sold.

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(2) Direct mining costs per ton is defined as cost of coal sales, exclusive of items shown separately, divided by tons sold.

(3) For more information, please read "Prospectus Summary—Summary Historical and Pro Forma Financial and Other Data."

(4) We expect to retain approximately $ million of the net proceeds from this offering and borrow $ million under our new revolving credit facility to fund capital expenditures.

(5) Reflects incremental general and administrative expenses that we expect to incur as a result of operating as a publicly traded partnership that are not reflected in our pro forma financial statements.

Estimated Cash Available for Distribution

The following table sets forth our calculation of forecasted cash available for distribution to our unitholders and general partner for the twelve months ending June 30, 2016. We forecast that our cash available for distribution generated during the twelve months ending June 30, 2016 will be approximately $ million. This amount in the aggregate would be sufficient to pay the minimum quarterly distribution of $ per unit on all of our common and subordinated units for each quarter during this period. Since our revenue and cash available for distribution will likely fluctuate over time as a result of changes in coal prices as well as other factors, the board of directors of our general partner expects to reserve all or a portion of any cash generated in excess of the amount sufficient to pay the full minimum quarterly distribution on all units, as a whole, to allow us to maintain and to gradually increase our quarterly cash distributions.

We are providing the financial forecast to supplement our historical consolidated financial statements in support of our belief that we will have sufficient cash available to allow us to pay distributions on all of our common and subordinated units for each quarter in the twelve months ending June 30, 2016 at the minimum quarterly distribution rate. Please read "—Significant Assumptions and Considerations" for further information as to the assumptions we have made for the financial forecast. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates" for information as to the accounting policies we have followed for the financial forecast.

Our forecast reflects our judgment as of the date of this prospectus of conditions we expect to exist and the course of action we expect to take during the twelve months ending June 30, 2016. We believe that our actual results of operations will approximate those reflected in our forecast, but we can give no assurance that our forecasted results will be achieved. If our estimates are not achieved, we may not be able to pay distributions on our common and subordinated units at the minimum quarterly distribution rate of $ per unit each quarter (or $ per unit on an annualized basis) or any other rate. The assumptions and estimates underlying the forecast are inherently uncertain and, though we consider them reasonable as of the date of this prospectus, are subject to a wide variety of significant business, economic, and competitive risks and uncertainties that could cause actual results to differ materially from those contained in the forecast, including, among others, risks and uncertainties contained in "Risk Factors." Accordingly, there can be no assurance that the forecast is indicative of our future performance or that actual results will not differ materially from those presented in the forecast. Inclusion of the forecast in this prospectus should not be regarded as a representation by any person that the results contained in the forecast will be achieved.

We do not, as a matter of course, make public forecasts as to future sales, earnings or other results. However, we have prepared the following forecast to present the forecasted cash available for distribution to our unitholders and general partner during the forecasted period. The accompanying forecast was not prepared with a view toward complying with the guidelines established by the American Institute of Certified Public Accountants with respect to prospective financial information, but, in our view, was prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of management's knowledge and belief, the expected course of

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action and our expected future financial performance. However, this information is not necessarily indicative of future results.

Neither our independent auditors, nor any other independent accountants, have compiled, examined or performed any procedures with respect to the forecast contained herein, nor have they expressed any opinion or any other form of assurance on such information or its achievability, and assume no responsibility for, and disclaim any association with, the forecast. We do not undertake to release publicly after this offering any revisions or updates to the financial forecast or the assumptions on which our forecasted results of operations are based.

	Twelve Months Ending June 30, 2016
	(in thousands, except per unit and per ton data)
Operating Data:	
Tons produced	
Tons sold	
Coal sales realized per ton(1)	$
Direct mining costs per ton(2)	$
Financial Data:	
Coal sales	$
Other revenues, net	
Costs and expenses:	
Cost of coal sales, exclusive of items shown separately below	
Transportation	
Depreciation, depletion and amortization	
Accretion on asset retirement obligations	
Selling, general and administrative	
Amortization of acquired sales contracts, net	
Operating income	$
Other expenses:	
Interest expense and related financing costs	
Net income	$
Adjustments to reconcile to EBITDA:	
Add:	
Depreciation, depletion and amortization	
Amortization of acquired sales contracts, net	
Interest expense and related financing costs	
EBITDA(3)	$
Adjustments to reconcile to Adjusted EBITDA:	
Add:	
Accretion on asset retirement obligations	
Adjusted EBITDA(3)	$
Adjustments to reconcile to estimated cash available for distribution:	
Add:	
Net proceeds from this offering or borrowings to fund capital expenditures(4)	
Less:	
Cash interest expense	
Expansion capital expenditures	
Accrual for maintenance capital expenditures(5)	
Estimated cash available for distribution	$
Minimum quarterly distribution per unit (annualized)	$

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	Twelve Months Ending June 30, 2016 (in thousands, except per unit and per ton data)
Distributions (annualized):	
Estimated distributions to common unitholders—public	$
Estimated distributions to common unitholders—sponsor	
Estimated distributions to subordinated unitholders—sponsor	
Total distributions	$
Excess	$

(1) Coal sales realized per ton is defined as coal sales divided by tons sold.

(2) Direct mining costs per ton is defined as cost of coal sales, exclusive of items shown separately, divided by tons sold.

(3) For more information, please read "Prospectus Summary—Summary Historical and Pro Forma Financial and Other Data."

(4) We expect to retain approximately $ million of the net proceeds from this offering and borrow $ million under our new revolving credit facility to fund capital expenditures.

(5) Reflects the annual accrual necessary to fund the estimated cost to maintain our long-term operating capacity or net income. Please read "How We Make Distributions To Our Partners—Operating Surplus and Capital Surplus—Capital Expenditures."

Significant Assumptions and Considerations

The forecast has been prepared by and is the responsibility of our management. Our forecast reflects our judgment as of the date of this prospectus of conditions we expect to exist and the course of action we expect to take during the twelve months ending June 30, 2016. While the assumptions disclosed in this prospectus are not all-inclusive, the assumptions listed are those that we believe are significant to our forecasted results of operations. We believe we have a reasonable objective basis for these assumptions. We believe our actual results of operations will approximate those reflected in our forecast, but we can give no assurance that our forecasted results will be achieved. There will likely be differences between our forecast and the actual results, and those differences could be material. If the forecast is not achieved, we may not be able to pay cash distributions on our common units at the minimum distribution rate or at all.

Coal Sales

We estimate that our coal sales for the twelve months ending June 30, 2016 will be approximately $ million, as compared to approximately $ million for the year ended December 31, 2014 and $ million for the twelve months ended March 31, 2015. Our forecast is based on the following assumptions:

- We estimate that we will produce million tons of coal for the twelve months ending June 30, 2016, as compared to million tons produced for the year ended December 31, 2014 and million tons produced for the twelve months ended March 31, 2015. Production from our coal operations for the forecast period is expected to increase from the year ended December 31, 2014 and the twelve months ended March 31, 2015 based on increased production at all three of our mines.

- We estimate that we will sell million tons of coal for the twelve months ending June 30, 2016 as compared to million tons sold for the year ended December 31, 2014 and million tons for the twelve months ended March 31, 2015. Tons sold for the forecast period is expected to increase from the year ended December 31, 2014 and the twelve months ended March 31, 2015 due to increased sales from our Sufco mine.

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- We estimate that our coal sales realized per ton (defined as coal sales per ton sold) will be $ for the twelve months ending June 30, 2016, as compared to $ for the year ended December 31, 2014 and $ for the twelve months ended March 31, 2015. The increase in realization from both periods is driven primarily by scheduled contractual price increases under our coal supply agreements.

Cost of Coal Sales, Exclusive of Items Shown Separately

We estimate that our cost of coal sales, exclusive of items shown separately (as defined in Appendix B), for the twelve months ending June 30, 2016 will be approximately $ million, as compared to approximately $ million for the year ended December 31, 2014 and $ million for the twelve months ended March 31, 2015. Our forecast is based on the following assumptions:

- We estimate that we will increase production during the forecast period by % and %, compared to the year ended December 31, 2014 and the twelve months ended March 31, 2015, respectively.

- We forecast that our direct mining costs per ton (defined as cost of coal sales, exclusive of items shown separately, divided by tons sold) will be $ for the twelve months ending June 30, 2016 as compared to $ for the year ended December 31, 2014 and $ for the twelve months ended March 31, 2015. The increase in direct mining costs per ton versus the year ended December 31, 2014 and the twelve months ended March 31, 2015 is primarily driven by increased coal preparation costs for deliveries to the Hunter Power Plant.

Our forecast cost of coal sales, exclusive of items shown separately, could vary significantly because of a large number of variables, many of which are beyond our control.

Transportation

We estimate that transportation expense for the twelve months ending June 30, 2016 will be approximately $ million, as compared to approximately $ million for the year ended December 31, 2014 and $ million for the twelve months ended March 31, 2015. The increase in transportation expense for the forecast period is due to additional coal sales under our new 15-year coal supply agreement with PacifiCorp for delivery to the Huntington Power Plant that will be supplied via truck from our Skyline mine. These costs are primarily passed through to the customer.

Depreciation, Depletion and Amortization

We estimate that depreciation, depletion and amortization for the twelve months ending June 30, 2016 will be approximately $ million, as compared to approximately $ million for the year ended December 31, 2014 and $ million for the twelve months ended March 31, 2015. The decrease in depreciation, depletion and amortization is primarily attributable to our expectation that, during the forecast period, we will obtain control of reserves previously identified as non-reserve coal deposits, which will increase the lives of our mines.

Selling, General and Administrative

We estimate that selling, general and administrative expenses for the twelve months ending June 30, 2016 will be approximately $ million, as compared to approximately $ million for the year ended December 31, 2014 and $ million for the twelve months ended March 31, 2015. The decrease in selling, general and administrative expenses during the forecast period as compared to the year ended December 31, 2014 and the twelve months ended March 31, 2015 is primarily due to lower professional fees related to acquisitions.

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Amortization of Acquired Sales Contracts

We estimate that amortization of acquired sales contracts for the twelve months ending June 30, 2016 will be approximately $ million, as compared to approximately $ million for the year ended December 31, 2014 and $ million for the twelve months ended March 31, 2015. The decrease during the forecast period from the year ended December 31, 2014 and the twelve months ended March 31, 2015 is due to the amortization period of the acquired sales contracts ending on December 31, 2015.

Interest Expense, Net

We estimate that interest expense for the twelve months ending June 30, 2016 will be approximately $ million, as compared to approximately $ million for the year ended December 31, 2014 and $ million for the twelve months ended March 31, 2015. The decrease in interest expense during the forecast period as compared to the year ended December 31, 2014 and the twelve months ended March 31, 2015 is due to principal payments on long-term debt.

Capital Expenditures

Our partnership agreement will distinguish between maintenance capital expenditures (which are cash expenditures made to maintain our long-term operating capacity or net income) and expansion capital expenditures (which are cash expenditures, including transaction expenses, made to increase our operating capacity or net income over the long term). We forecast capital expenditures for the twelve months ending June 30, 2016 based on the following assumptions:

- We estimate that our maintenance capital expenditures for the twelve months ending June 30, 2016 will be approximately $ million, as compared to approximately $ million for the year ended December 31, 2014 and $ million for the twelve months ended March 31, 2015. The increase in capital expenditures as compared to the year ended December 31, 2014 and the twelve months ended March 31, 2015 is primarily due to rebuilding equipment at, and the extension of existing mine development of, the Sufco and Skyline mines.

- We do not currently expect to have any expansion capital expenditures for the twelve months ending June 30, 2016. For purposes of this presentation, we have assumed that all expansion capital expenditures will be funded with borrowings or cash on hand.

Estimated maintenance capital expenditures reduce operating surplus, but expansion capital expenditures, actual maintenance capital expenditures and investment capital expenditures do not. Maintenance capital expenditures are those expenditures made to maintain our long-term operating capacity or net income. Examples of maintenance capital expenditures include expenditures associated with the replacement of equipment and coal reserves, whether through the extension of an existing mine or the acquisition or development of new reserves, to the extent such expenditures are made to maintain, over the long term, our operating capacity or net income as they exist at such time as the capital expenditures are made. Maintenance capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued (including incremental distributions on incentive distribution rights) to finance all or any portion of the construction or development of a replacement asset that is paid in respect of the period that begins when we enter into a binding obligation to commence constructing or developing a replacement asset and ending on the earlier to occur of the date that any such replacement asset commences commercial service and the date that it is abandoned or disposed of. Our general partner will review all capital expenditures on an annual basis in connection with the budget process and on a quarterly basis at the time expenditures are made to determine which expenditures increase current operating capacity or net income over the long term. Factors our general partner will consider include an assessment of current operating capacity or net income of the mine at the time of the expenditure and an evaluation of whether the expenditure will increase the mine's capacity or net income or whether the expenditure will replace current operating

capacity or net income. To the extent the capital expenditure increases operating capacity or net income in a sustainable way, it will be classified as an expansion capital expenditure in the period in which the expenditure was made. Otherwise, it will be considered a maintenance capital expenditure. As an example, the capital expenditure related to the development of a new mine would be considered an expansion capital expenditure since it increases the current operating capacity or net income over the long term. In contrast, the rebuild of a pre-existing continuous miner unit would be considered a maintenance capital expenditure as it would not result in a sustainable, long-term increase to our operating capacity or net income but rather will maintain our current operating capacity. Cash expenditures made solely for investment purposes will not be considered maintenance capital expenditures.

On June 17, 2015, we were notified by the BLM, as part of the lease by application process, that we submitted the only bid in the competitive lease sale of the Flat Canyon tract held on June 17, 2015. On June 19, 2015, we were notified by the BLM, as part of the lease by application process, that our bid met or exceeded the BLM's estimate of the fair market value of the tract. The Flat Canyon tract contains proven and probable reserves that are contiguous to the coal reserves we are mining at our Skyline mine, and as such, our development and mining of the proven and probable reserves in the Flat Canyon tract will not require capital expenditures for additional surface infrastructure. The Flat Canyon tract is expected to extend the useful life of our Skyline mine, and we do not currently expect that, at the time capital expenditures are made to develop the Flat Canyon tract, such expenditures will increase, over the long term, our operating capacity or net income in place at such time. We currently expect that the capital expenditures we incur in developing the Flat Canyon tract will be categorized as maintenance capital expenditures. The issuance by the BLM of the lease of the Flat Canyon tract remains subject to a 30-day antitrust review by the U.S. Department of Justice. The leasing action could also be challenged in the Department of Interior's Board of Land Appeals or in federal district court. The May 15, 2015 Notice of Lease Sale of the Flat Canyon tract prompted letters by several non-governmental organizations objecting to the lease sale on, among other things, environmental grounds. Please read "Business—Coal Reserves and Non-Reserve Coal Deposits—Reserve Acquisition Process."

On June 5, 2015, we acquired the Fossil Rock reserves from an affiliate of PacifiCorp. We believe the Fossil Rock reserves will provide a natural replacement for the low sulfur coal currently produced by our Sufco mine from the Upper Hiawatha seam, which we expect to be exhausted in the third quarter of 2021. We currently expect that the capital expenditures we incur in building the necessary surface infrastructure at and developing the Fossil Rock reserves will be categorized as maintenance capital expenditures. However, depending on market conditions and our ability to produce and sell coal from the Sufco mine's Lower Hiawatha seam (assuming our receipt of the Greens Hollow tract from the BLM through the lease by application process), it is possible that we may make capital expenditures with respect to the Fossil Rock reserves that could be viewed as increasing our operating capacity or net income, and thus such capital expenditures could be categorized as expansion capital expenditures. For more information regarding the lease by application process, please see "Business—Coal Reserves and Non-Reserve Coal Deposits—Reserve Acquisition Process."

Regulatory, Industry and Economic Factors

We forecast our results of operations for the twelve months ending June 30, 2016 based on the following assumptions related to regulatory, industry and economic factors:

- no material nonperformance or credit-related defaults by suppliers, customers or vendors, or shortage of skilled labor;
- all supplies and commodities necessary for production and sufficient transportation will be readily available;

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- no new federal, state or local regulation of the portions of the mining industry in which we operate or any interpretation of existing regulation that in either case will be materially adverse to our business;
- no material unforeseen geological conditions or equipment problems at our mining locations; and
- no material accidents, releases, weather-related incidents, unscheduled downtime or similar unanticipated events.

Quarterly Forecast Information

The following table sets forth our calculation of forecasted cash available for distribution to our unitholders and general partner on a quarter-by-quarter basis for the forecast period. The following forecast reflects our judgment as of the date of this prospectus of conditions we expect to exist and the course of action we expect to take for the twelve months ending June 30, 2016. Please see "—Significant Assumptions and Considerations." The assumptions and considerations underlying the forecast for the twelve months ending June 30, 2016 are inherently uncertain, and estimating the precise quarter in which each revenue and expense will be recognized increases the level of uncertainty

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of the quarterly forecast information. Accordingly, actual quarter-by-quarter results may differ materially from the quarter-by-quarter forecast information presented below.

	Three Months Ending September 30, 2015	Three Months Ending December 31, 2015	Three Months Ending March 31, 2016	Three Months Ending June 30, 2016
	(in thousands, except per unit and per ton data)			
Operating Data:				
Tons produced				
Tons sold				
Coal sales realized per ton(1)	$	$	$	$
Direct mining costs per ton(2)	$	$	$	$
Financial Data:				
Coal sales	$	$	$	$
Other revenues, net				
Costs and expenses:				
Cost of coal sales, exclusive of items shown separately below				
Transportation				
Depreciation, depletion and amortization				
Accretion on asset retirement obligations				
Selling, general and administrative				
Amortization of acquired sales contracts, net				
Operating income	$	$	$	$
Other expenses:				
Interest expense and related financing costs				
Net income	$	$	$	$
Adjustments to reconcile to EBITDA:				
Add:				
Depreciation, depletion and amortization				
Amortization of acquired sales contracts, net				
Interest expense and related financing costs				
EBITDA(3)	$	$	$	$
Adjustments to reconcile to Adjusted EBITDA:				
Add:				
Accretion on asset retirement obligations				
Adjusted EBITDA(3)	$	$	$	$
Adjustments to reconcile to estimated cash available for distribution:				
Add:				
Net proceeds from this offering or borrowings to fund capital expenditures(4)				
Less:				
Cash interest expense				
Expansion capital expenditures				
Accrual for maintenance capital expenditures(5)				
Estimated cash available for distribution	$	$	$	$
Minimum quarterly distribution per unit	$	$	$	$

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	Three Months Ending September 30, 2015	Three Months Ending December 31, 2015	Three Months Ending March 31, 2016	Three Months Ending June 30, 2016
	(in thousands, except per unit and per ton data)			
Distributions:				
Estimated distributions to common unitholders—public	$	$	$	$
Estimated distributions to common unitholders—sponsor				
Estimated distributions to subordinated unitholders—sponsor				
Total distributions	$	$	$	$
Excess	$	$	$	$

(1) Coal sales realized per ton is defined as coal sales divided by tons sold.

(2) Direct mining costs per ton is defined as cost of coal sales, exclusive of items shown separately, divided by tons sold.

(3) For more information, please read "Prospectus Summary—Summary Historical and Pro Forma Financial and Other Data."

(4) We expect to retain approximately $ million of the net proceeds from this offering and borrow $ million under our new revolving credit facility to fund capital expenditures.

(5) Reflects the annual accrual necessary to fund the estimated cost to maintain our long-term operating capacity or net income. Please read "How We Make Distributions To Our Partners—Operating Surplus and Capital Surplus—Capital Expenditures."

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HOW WE MAKE DISTRIBUTIONS TO OUR PARTNERS

General

Our partnership agreement provides that our general partner will make a determination as to whether to make a distribution, but our partnership agreement does not require us to pay distributions at any time or in any amount. Instead, the board of directors of our general partner will adopt a cash distribution policy to be effective as of the closing of this offering that will set forth our general partner's intention with respect to the distributions to be made to unitholders. Pursuant to our cash distribution policy, within 60 days after the end of each quarter, beginning with the quarter ending , 2015, we intend to distribute to the holders of common and subordinated units on a quarterly basis at least the minimum quarterly distribution of $ per unit, or $ on an annualized basis, to the extent we have sufficient cash after establishment of cash reserves and payment of fees and expenses, including payments to our general partner and its affiliates. We will prorate the quarterly distribution for the period after the closing of this offering through , 2015.

The board of directors of our general partner may change the foregoing distribution policy at any time and from time to time, and even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner. Our partnership agreement does not contain a requirement for us to pay distributions to our unitholders, and there is no guarantee that we will pay the minimum quarterly distribution, or any distribution, on the units in any quarter. However, our partnership agreement does contain provisions intended to motivate our general partner to make steady, increasing and sustainable distributions over time.

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions.

Operating Surplus and Capital Surplus

General

Any distributions we make will be characterized as made from "operating surplus" or "capital surplus." Distributions from operating surplus are made differently than cash distributions that we would make from capital surplus. Operating surplus distributions will be made to our unitholders and, if we make quarterly distributions above the first target distribution level described below, to the holder of our incentive distribution rights. We do not anticipate that we will make any distributions from capital surplus. In such an event, however, any capital surplus distribution would be made pro rata to all unitholders, but the incentive distribution rights would generally not participate in any capital surplus distributions. Any distribution from capital surplus would result in a reduction of the minimum quarterly distribution and target distribution levels and, if we reduce the minimum quarterly distribution to zero and eliminate any unpaid arrearages, thereafter capital surplus would be distributed as if it were operating surplus and the incentive distribution rights would thereafter be entitled to participate in such distributions. Please read "—Distributions From Capital Surplus."

Operating Surplus

We define operating surplus as:

- $ million (as described below); *plus*
- all of our cash receipts after the closing of this offering, excluding cash from interim capital transactions (as defined below) and provided that cash receipts from the termination of any hedge contract prior to its stipulated settlement or termination date will be included in equal quarterly installments over the remaining scheduled life of such hedge contract had it not been terminated; *plus*

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- cash distributions paid in respect of equity issued (including incremental distributions on incentive distribution rights), other than equity issued in this offering, to finance all or a portion of expansion capital expenditures in respect of the period that commences when we enter into a binding obligation for the acquisition, construction, development or expansion and ending on the earlier to occur of the date any acquisition, construction, development or expansion commences commercial service and the date that it is disposed of or abandoned; *plus*

- cash distributions paid in respect of equity issued (including incremental distributions on incentive distribution rights) to pay the construction period interest on debt incurred, or to pay construction period distributions on equity issued, to finance the expansion capital expenditures referred to above, in each case, in respect of the period that commences when we enter into a binding obligation for the acquisition, construction, development or expansion and ending on the earlier to occur of the date any acquisition, construction, development or expansion commences commercial service and the date that it is disposed of or abandoned; *plus*

- an amount equal to the net proceeds from this offering that are retained for general partnership purposes, up to the amount of accounts receivable distributed to our sponsor prior to the closing of this offering; *less*

- all of our operating expenditures (as defined below) after the closing of this offering; *less*

- the amount of cash reserves established by our general partner to provide funds for future operating expenditures; *less*

- all working capital borrowings not repaid within twelve months after having been incurred or repaid within such twelve month period with the proceeds of additional working capital borrowings; *less*

- any cash loss realized on disposition of an investment capital expenditure.

Disbursements made, cash received (including working capital borrowings) or cash reserves established, increased or reduced after the end of a period but on or before the date on which cash or cash equivalents will be distributed with respect to such period shall be deemed to have been made, received, established, increased or reduced, for purposes of determining operating surplus, within such period if our general partner so determines. Furthermore, cash received from an interest in an entity for which we account using the equity method will not be included to the extent it exceeds our proportionate share of that entity's operating surplus (calculated as if the definition of operating surplus applied to such entity from the date of our acquisition of such an interest without any basket similar to that described in the first bullet above). Operating surplus does not reflect cash generated by our operations. For example, it includes a basket of $ million that will enable us, if we choose, to distribute as operating surplus cash we receive in the future from non-operating sources such as asset sales, issuances of securities and long-term borrowings that would otherwise be distributed as capital surplus. In addition, the effect of including, as described above, certain cash distributions on equity interests in operating surplus will be to increase operating surplus by the amount of any such cash distributions. As a result, we may also distribute as operating surplus up to the amount of any such cash that we receive from non-operating sources.

The proceeds of working capital borrowings increase operating surplus and repayments of working capital borrowings are generally operating expenditures, as described below, and thus reduce operating surplus when made. However, if a working capital borrowing is not repaid during the twelve-month period following the borrowing, it will be deducted from operating surplus at the end of such period, thus decreasing operating surplus at such time. When such working capital borrowing is in fact repaid, it will be excluded from operating expenditures because operating surplus will have been previously reduced by the deduction.

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We define operating expenditures in our partnership agreement, and it generally means all of our cash expenditures, including taxes, reimbursement of expenses to our general partner or its affiliates, payments made under hedge contracts (provided that (1) with respect to amounts paid in connection with the initial purchase of a hedge contract, such amounts will be amortized over the life of the applicable hedge contract and (2) payments made in connection with the termination of any hedge contract prior to the expiration of its stipulated settlement or termination date will be included in operating expenditures in equal quarterly installments over the remaining scheduled life of such hedge contract), officer compensation, repayment of working capital borrowings, interest on indebtedness and estimated maintenance capital expenditures (as discussed in further detail below), provided that operating expenditures will not include:

- repayment of working capital borrowings deducted from operating surplus pursuant to the penultimate bullet point of the definition of operating surplus above when such repayment actually occurs;
- payments (including prepayments and prepayment penalties and the purchase price of indebtedness that is repurchased and cancelled) of principal of and premium on indebtedness, other than working capital borrowings;
- expansion capital expenditures;
- actual maintenance capital expenditures;
- investment capital expenditures;
- payment of transaction expenses relating to interim capital transactions;
- distributions to our partners (including distributions in respect of our incentive distribution rights);
- repurchases of equity interests except to fund obligations under employee benefit plans; or
- any other expenditures or payments using the proceeds of this offering that are described in "Use of Proceeds."

Capital Surplus

Capital surplus is defined in our partnership agreement as any cash distributed in excess of our operating surplus. Accordingly, capital surplus would generally be generated only by the following (which we refer to as "interim capital transactions"):

- borrowings other than working capital borrowings;
- sales of our equity interests; and
- sales or other dispositions of assets for cash, other than inventory, accounts receivable and other assets sold in the ordinary course of business or as part of normal retirement or replacement of assets.

Characterization of Cash Distributions

Our partnership agreement provides that we treat all cash distributed as coming from operating surplus until the sum of all cash distributed since the closing of this offering (other than any distributions of proceeds of this offering) equals the operating surplus from the closing of this offering. Our partnership agreement provides that we treat any amount distributed in excess of operating surplus, regardless of its source, as distributions of capital surplus. We do not anticipate that we will make any distributions from capital surplus.

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Capital Expenditures

Our partnership agreement will distinguish between maintenance capital expenditures (which are cash expenditures made to maintain our long-term operating capacity or net income), expansion capital expenditures (which are cash expenditures, including transaction expenses, made to increase our operating capacity or net income over the long-term) and investment capital expenditures (capital expenditures that are neither maintenance capital expenditures nor expansion capital expenditures). Our general partner will determine the amount of expenditures made to maintain or increase our long-term operating capacity or net income.

Estimated maintenance capital expenditures reduce operating surplus, but expansion capital expenditures, actual maintenance capital expenditures and investment capital expenditures do not. Examples of maintenance capital expenditures include expenditures associated with the replacement of equipment and coal reserves, whether at an existing mine or the acquisition or development of new reserves, to the extent such expenditures are made to maintain our then current operating capacity or net income as they exist at such time as the capital expenditures are made. Maintenance capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued (including incremental distributions on incentive distribution rights) to finance all or any portion of the construction or development of a replacement asset that is paid in respect of the period that begins when we enter into a binding obligation to commence constructing or developing a replacement asset and ending on the earlier to occur of the date that any such replacement asset commences commercial service and the date that it is abandoned or disposed of. Our general partner will review all capital expenditures on an annual basis in connection with the budget process and on a quarterly basis at the time expenditures are made to determine which expenditures increase current operating capacity or net income over the long term. Factors our general partner will consider include an assessment of current operating capacity or net income of the mine at the time of the expenditure and an evaluation of whether the expenditure will increase the mine's capacity or net income or whether the expenditure will replace current operating capacity or net income. To the extent the capital expenditure increases operating capacity or net income over the long term, it will be classified as an expansion capital expenditure in the period in which the expenditure was made. Otherwise, it will be considered a maintenance capital expenditure. Cash expenditures made solely for investment purposes will not be considered maintenance capital expenditures.

Because our maintenance capital expenditures can be irregular, the amount of our actual maintenance capital expenditures may differ substantially from period to period, which could cause similar fluctuations in the amounts of operating surplus if we subtracted actual maintenance capital expenditures from operating surplus.

To eliminate these fluctuations, our partnership agreement will require that an estimate of the average quarterly maintenance capital expenditures necessary to maintain our operating capacity over the long-term be subtracted from operating surplus each quarter as opposed to the actual amounts spent. The amount of estimated maintenance capital expenditures deducted from operating surplus for those periods will be subject to review and change by our general partner at least once a year, provided that any change is approved by our conflicts committee. The estimate will be made at least annually and whenever an event occurs that is likely to result in a material adjustment to the amount of our maintenance capital expenditures, including a major acquisition or expansion or the introduction of new governmental regulations that will impact our business. For purposes of calculating operating surplus, any adjustment to this estimate will be prospective only. For a discussion of the amounts we have allocated toward estimated maintenance capital expenditures, please read "Cash Distribution Policy and Restrictions on Distributions."

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The use of estimated maintenance capital expenditures in calculating operating surplus will have the following effects:

- the amount of actual maintenance capital expenditures in any quarter will not directly reduce operating surplus but will instead be factored into the estimate of the average quarterly maintenance capital expenditures. This may result in the subordinated units converting into common units when the use of actual maintenance capital expenditures would result in lower operating surplus during the subordination period and potentially result in the tests for conversion of the subordinated units not being satisfied;

- it may increase our ability to distribute as operating surplus cash we receive from non-operating sources; and

- it may be more difficult for us to raise our distribution above the minimum quarterly distribution and pay incentive distributions on the incentive distribution rights held by our general partner.

Expansion capital expenditures are those cash expenditures, including transaction expenses, made to increase our operating capacity or net income over the long term. Examples of expansion capital expenditures include the acquisition of reserves, equipment or a new mine or the expansion of an existing mine, in each case to the extent such expenditures are expected to expand our long-term operating capacity or increase our net income. Expansion capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued (including incremental distributions on incentive distribution rights) to finance all or any portion of such acquisition or expansion in respect of the period that commences when we enter into a binding obligation for the acquisition, construction, development or expansion and ending on the earlier to occur of the date any acquisition construction, development or expansion commences commercial service and the date that it is disposed of or abandoned. Expenditures made solely for investment purposes will not be considered expansion capital expenditures.

Investment capital expenditures are those capital expenditures, including transaction expenses, that are neither maintenance capital expenditures nor expansion capital expenditures. Investment capital expenditures largely will consist of capital expenditures made for investment purposes. Examples of investment capital expenditures include traditional capital expenditures for investment purposes, such as purchases of securities, as well as other capital expenditures that might be made in lieu of such traditional investment capital expenditures, such as the acquisition of an asset for investment purposes or development of assets that are in excess of the maintenance of our existing operating capacity or net income, but which are not expected to expand, for more than the short term, our operating capacity or net income.

As described above, neither investment capital expenditures nor expansion capital expenditures are operating expenditures, and thus will not reduce operating surplus. Because expansion capital expenditures include interest payments (and related fees) on debt incurred to finance all or a portion of an acquisition, development or expansion in respect of a period that begins when we enter into a binding obligation for an acquisition construction, development or expansion and ending on the earlier to occur of the date on which such acquisition, construction, development or expansion commences commercial service and the date that it is abandoned or disposed of, such interest payments also do not reduce operating surplus. Losses on disposition of an investment capital expenditure will reduce operating surplus when realized and cash receipts from an investment capital expenditure will be treated as a cash receipt for purposes of calculating operating surplus only to the extent the cash receipt is a return on principal.

Cash expenditures that are made in part for maintenance capital purposes, investment capital purposes or expansion capital purposes will be allocated as maintenance capital expenditures, investment capital expenditures or expansion capital expenditures by our general partner.

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Subordination Period

General

Our partnership agreement provides that, during the subordination period (which we describe below), the common units will have the right to receive distributions from operating surplus each quarter in an amount equal to $ per common unit, which amount is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions from operating surplus may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distribution from operating surplus for any quarter until the common units have received the minimum quarterly distribution from operating surplus for such quarter plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be sufficient cash from operating surplus to pay the minimum quarterly distribution on the common units.

Determination of Subordination Period

Except as described below, the subordination period will begin on the closing date of this offering and expire on the first business day after the distribution to unitholders in respect of any quarter, beginning with the quarter ending , 2018, if each of the following has occurred:

- for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date, aggregate distributions from operating surplus equaled or exceeded the sum of the minimum quarterly distribution multiplied by the total number of common and subordinated units outstanding in each quarter in each period;

- for the same three consecutive, non-overlapping four-quarter periods, the "adjusted operating surplus" (as described below) equaled or exceeded the sum of the minimum quarterly distribution multiplied by the total number of common and subordinated units outstanding during each quarter on a fully diluted weighted average basis; and

- there are no arrearages in payment of the minimum quarterly distribution on the common units.

For the period after the closing of this offering through , 2015, our partnership agreement will prorate the minimum quarterly distribution based on the actual length of the period, and use such prorated distribution for all purposes, including in determining whether the test described above has been satisfied.

Early Termination of Subordination Period

Notwithstanding the foregoing, the subordination period will automatically terminate, and all of the subordinated units will convert into common units on a one-for-one basis, on the first business day after the distribution to unitholders in respect of any quarter, beginning with the quarter ending , 2016, if each of the following has occurred:

- for one four-quarter period immediately preceding that date, aggregate distributions from operating surplus exceeded the sum of 150.0% of the minimum quarterly distribution multiplied by the total number of common units and subordinated units outstanding in each quarter in the period;

- for the same four-quarter period, the "adjusted operating surplus" (as described below) equaled or exceeded the sum of 150.0% of the minimum quarterly distribution multiplied by the total

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number of common and subordinated units outstanding during each quarter on a fully diluted weighted average basis, plus the related distribution on the incentive distribution rights; and

- there are no arrearages in payment of the minimum quarterly distributions on the common units.

Conversion Upon Removal of the General Partner

In addition, if the unitholders remove our general partner other than for cause, the subordinated units held by any person will immediately and automatically convert into common units on a one-for-one basis, provided (1) neither such person nor any of its affiliates voted any of its units in favor of the removal and (2) such person is not an affiliate of the successor general partner.

Expiration of the Subordination Period

When the subordination period ends, each outstanding subordinated unit will convert into one common unit and will then participate pro rata with the other common units in distributions.

Adjusted Operating Surplus

Adjusted operating surplus is intended to generally reflect the cash generated from operations during a particular period and therefore excludes net increases in working capital borrowings and net drawdowns of reserves of cash generated in prior periods if not utilized to pay expenses during that period. Adjusted operating surplus for any period consists of:

- operating surplus generated with respect to that period (excluding any amounts attributable to the items described in the first bullet point under "—Operating Surplus and Capital Surplus—Operating Surplus" above); *less*

- any net increase during that period in working capital borrowings; *less*

- any net decrease during that period in cash reserves for operating expenditures not relating to an operating expenditure made during that period; *less*

- any expenditures that are not operating expenditures solely because of the provision described in the last bullet point describing operating expenditures above; *plus*

- any net decrease during that period in working capital borrowings; *plus*

- any net increase during that period in cash reserves for operating expenditures required by any debt instrument for the repayment of principal, interest or premium; *plus*

- any net decrease made in subsequent periods in cash reserves for operating expenditures initially established during such period to the extent such decrease results in a reduction of adjusted operating surplus in subsequent periods pursuant to the third bullet point above.

Any disbursements received, cash received (including working capital borrowings) or cash reserves established, increased or reduced after the end of a period that the general partner determines to include in operating surplus for such period shall also be deemed to have been made, received or established, increased or reduced in such period for purposes of determining adjusted operating surplus for such period.

Distributions From Operating Surplus During the Subordination Period

If we make a distribution from operating surplus for any quarter ending before the end of the subordination period, our partnership agreement requires that we make the distribution in the following manner:

- *first*, to the common unitholders, pro rata, until we distribute for each common unit an amount equal to the minimum quarterly distribution for that quarter and any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters;

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- *second*, to the subordinated unitholders, pro rata, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and

- *thereafter*, in the manner described in "—General Partner Interest—Incentive Distribution Rights" below.

Distributions From Operating Surplus After the Subordination Period

If we make distributions of cash from operating surplus for any quarter ending after the subordination period, our partnership agreement requires that we make the distribution in the following manner:

- *first*, to all common unitholders, pro rata, until we distribute for each common unit an amount equal to the minimum quarterly distribution for that quarter; and

- *thereafter*, in the manner described in "—Incentive Distribution Rights" below.

General Partner Interest

Our general partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions. However, our general partner owns the incentive distribution rights and may in the future own common units or other equity interests in us and will be entitled to receive distributions on any such interests.

Incentive Distribution Rights

Incentive distribution rights represent the right to receive increasing percentages (15.0%, 25.0% and 50.0%) of quarterly distributions from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest.

If for any quarter:

- we have distributed cash from operating surplus to the common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and

- we have distributed cash from operating surplus to the common unitholders in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, we will make additional distributions from operating surplus for that quarter among the unitholders and the holders of the incentive distribution rights in the following manner:

- *first*, to all unitholders, pro rata, until each unitholder receives a total of $ per unit for that quarter (the "first target distribution");

- *second*, 85.0% to all common unitholders and subordinated unitholders, pro rata, and 15.0% to the holders of our incentive distribution rights, until each unitholder receives a total of $ per unit for that quarter (the "second target distribution");

- *third*, 75.0% to all common unitholders and subordinated unitholders, pro rata, and 25.0% to the holders of our incentive distribution rights, until each unitholder receives a total of $ per unit for that quarter (the "third target distribution"); and

- *thereafter*, 50.0% to all common unitholders and subordinated unitholders, pro rata, and 50.0% to the holders of our incentive distribution rights.

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Percentage Allocations of Distributions From Operating Surplus

The following table illustrates the percentage allocations of distributions from operating surplus between the unitholders and the holders of our incentive distribution rights based on the specified target distribution levels. The amounts set forth under the column heading "Marginal Percentage Interest in Distributions" are the percentage interests of the holders of our incentive distribution rights and the unitholders in any distributions from operating surplus we distribute up to and including the corresponding amount in the column heading "Total Quarterly Distribution Per Unit." The percentage interests shown for our unitholders and the holders of our incentive distribution rights for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below assume there are no arrearages on common units.

	Total Quarterly Distribution Per Unit		Marginal Percentage Interest in Distributions	
			Unitholders	IDR Holders
Minimum Quarterly Distribution	up to $		100.0%	0%
First Target Distribution	above $	up to $	100.0%	0%
Second Target Distribution	above $	up to $	85.0%	15.0%
Third Target Distribution	above $	up to $	75.0%	25.0%
Thereafter	above $		50.0%	50.0%

Incentive Distribution Right Holders' Right to Reset Incentive Distribution Levels

Our general partner, as the initial holder of our incentive distribution rights, has the right under our partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial target distribution levels and to reset, at higher levels, the target distribution levels upon which the incentive distribution payments would be set. If our general partner transfers all or a portion of the incentive distribution rights in the future, then the holder or holders of a majority of our incentive distribution rights will be entitled to exercise this right. The following discussion assumes that our general partner holds all of the incentive distribution rights at the time that a reset election is made.

The right to reset the target distribution levels upon which the incentive distributions are based may be exercised, without approval of our unitholders or the conflicts committee of our general partner at any time when there are no subordinated units outstanding and we have made cash distributions in excess of the highest then-applicable target distribution for the prior four consecutive fiscal quarters. The reset target distribution levels will be higher than the most recent per unit distribution level prior to the reset election and higher than the target distribution levels prior to the reset such that there will be no incentive distributions paid under the reset target distribution levels until cash distributions per unit following the reset event increase as described below. Because the reset target distribution levels will be higher than the most recent per unit distribution level prior to the reset, if we were to issue additional common units after the reset and maintain the per unit distribution level, no additional incentive distributions would be payable. By contrast, if there were no such reset and we were to issue additional common units and maintain the per unit distribution level, additional incentive distributions would have to be paid based on the additional number of outstanding common units and the percentage interest of the incentive distribution rights above the target distribution levels. Thus, the exercise of the reset right would lower our cost of equity capital. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would otherwise not be sufficiently accretive to cash distributions per common unit, taking into account the existing levels of incentive distribution payments being made.

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In connection with the resetting of the target distribution levels and the corresponding relinquishment by our general partner of incentive distribution payments based on the target cash distributions prior to the reset, our general partner will be entitled to receive a number of newly issued common units based on the formula described below that takes into account the "cash parity" value of the cash distributions related to the incentive distribution rights for the quarter prior to the reset event as compared to the cash distribution per common unit in such quarter.

The number of common units to be issued in connection with a resetting of the minimum quarterly distribution amount and the target distribution levels would equal the quotient determined by dividing (x) the amount of cash distributions received in respect of the incentive distribution rights for the fiscal quarter ended immediately prior to the date of such reset election by (y) the amount of cash distributed per common unit with respect to such quarter.

Following a reset election, the reset minimum quarterly distribution will be calculated and the target distribution levels will be reset to be correspondingly higher such that we would make distributions from operating surplus for each quarter thereafter as follows:

- *first*, to all common unitholders, pro rata, until each unitholder receives an amount per unit for that quarter equal to 115.0% of the reset minimum quarterly distribution;
- *second*, 85.0% to all common unitholders, pro rata, and 15.0% to the holders of our incentive distribution rights, until each unitholder receives an amount per unit for that quarter equal to 125.0% of the reset minimum quarterly distribution;
- *third*, 75.0% to all common unitholders, pro rata, and 25.0% to the holders of our incentive distribution rights, until each unitholder receives an amount per unit for that quarter equal to 150.0% of the reset minimum quarterly distribution; and
- *thereafter*, 50.0% to all common unitholders, pro rata, and 50.0% to the holders of our incentive distribution rights.

Because a reset election can only occur after the subordination period expires, the reset minimum quarterly distribution will have no significance except as a baseline for the target distribution levels.

The following table illustrates the percentage allocation of distributions from operating surplus between the unitholders and the holders of our incentive distribution rights at various distribution levels (1) pursuant to the distribution provisions of our partnership agreement in effect at the closing of this offering, as well as (2) following a hypothetical reset of the target distribution levels based on the assumption that the quarterly distribution amount per common unit during the fiscal quarter immediately preceding the reset election was $.

	Quarterly Distribution Per Unit Prior to Reset	Unitholders	Incentive Distribution Rights Holders	Quarterly Distribution Per Unit Following Hypothetical Reset
Minimum Quarterly Distribution	up to $	100.0%	0.0%	up to $ (1)
First Target Distribution	above $ up to $	100.0%	0.0%	above $ up to $ (2)
Second Target Distribution	above $ up to $	85.0%	15.0%	above $ up to $ (3)
Third Target Distribution	above $ up to $	75.0%	25.0%	above $ up to $ (4)
Thereafter	above $	50.0%	50.0%	above $

(1) This amount is equal to the hypothetical reset minimum quarterly distribution.

(2) This amount is 115.0% of the hypothetical reset minimum quarterly distribution.

(3) This amount is 125.0% of the hypothetical reset minimum quarterly distribution.

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(4) This amount is 150.0% of the hypothetical reset minimum quarterly distribution.

The following table illustrates the total amount of distributions from operating surplus that would be distributed to the unitholders and the holders of incentive distribution rights, based on the amount distributed for the quarter immediately prior to the reset. The table assumes that immediately prior to the reset there would be common units outstanding and the distribution to each common unit would be $ for the quarter prior to the reset.

	Quarterly Distribution per Unit Prior to Reset	Cash Distributions to Common Unitholders Prior to Reset	Cash Distributions to Holders of Incentive Distribution Rights Prior to Reset	Total Distributions
Minimum Quarterly Distribution	up to $	$	$	$
First Target Distribution	above $ up to $			
Second Target Distribution	above $ up to $			
Third Target Distribution	above $ up to $			
Thereafter	above $			
		$	$	$

The following table illustrates the total amount of distributions from operating surplus that would be distributed to the unitholders and the holders of our incentive distribution rights, with respect to the quarter in which the reset occurs. The table reflects that as a result of the reset there would be common units outstanding and the distribution to each common unit would be $. The number of common units to be issued upon the reset was calculated by dividing (1) the amount received in respect of the incentive distribution rights for the quarter prior to the reset as shown in the table above, or $, by (2) the amount of cash distributed on each common unit for the quarter prior to the reset as shown in the table above, or $.

	Quarterly Distribution per Unit Prior to Reset	Cash Distributions to Common Unitholders Prior to Reset	Cash Distributions to Holders of Incentive Distribution Rights After Reset			Total Distributions
			Common Units(1)	Incentive Distribution Rights	Total	
Minimum Quarterly Distribution	up to $	$	$	$	$	$
First Target Distribution	above $ up to $					
Second Target Distribution	above $ up to $					
Third Target Distribution	above $ up to $					
Thereafter	above $					
		$	$	$	$	$

(1) Represents distributions in respect of the common units issued upon the reset.

The holders of incentive distribution rights will be entitled to cause the target distribution levels to be reset on more than one occasion.

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Distributions From Capital Surplus

How Distributions From Capital Surplus Will Be Made

Our partnership agreement requires that we make distributions from capital surplus, if any, in the following manner:

- *first*, to all common unitholders and subordinated unitholders, pro rata, until the minimum quarterly distribution is reduced to zero, as described below;
- *second*, to the common unitholders, pro rata, until we distribute for each common unit an amount from capital surplus equal to any unpaid arrearages in payment of the minimum quarterly distribution on the common units; and
- *thereafter*, we will make all distributions from capital surplus as if they were from operating surplus.

Effect of a Distribution From Capital Surplus

Our partnership agreement treats a distribution from capital surplus as the repayment of the initial unit price from this initial public offering, which is a return of capital. Each time a distribution from capital surplus is made, the minimum quarterly distribution and the target distribution levels will be reduced in the same proportion as the distribution from capital surplus to the fair market value of the common units prior to the announcement of the distribution. Because distributions of capital surplus will reduce the minimum quarterly distribution and target distribution levels after any of these distributions are made, it may be easier for our general partner to receive incentive distributions and for the subordinated units to convert into common units. However, any distribution from capital surplus before the minimum quarterly distribution is reduced to zero cannot be applied to the payment of the minimum quarterly distribution or any arrearages.

Once we reduce the minimum quarterly distribution and target distribution levels to zero, all future distributions will be made such that 50.0% is paid to all unitholders, pro rata, and 50.0% is paid to the holder or holders of incentive distribution rights.

Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels

In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution from capital surplus, if we combine our common units into fewer common units or subdivide our common units into a greater number of common units, our partnership agreement specifies that the following items will be proportionately adjusted:

- the minimum quarterly distribution;
- the target distribution levels;
- the initial unit price, as described below under "—Distributions of Cash Upon Liquidation";
- the per unit amount of any outstanding arrearages in payment of the minimum quarterly distribution on the common units; and
- the number of subordinated units.

For example, if a two-for-one split of the common units should occur, the minimum quarterly distribution, the target distribution levels and the initial unit price would each be reduced to 50.0% of its initial level. If we combine our common units into a lesser number of units or subdivide our common units into a greater number of units, we will combine or subdivide our subordinated units

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using the same ratio applied to the common units. We will not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if as a result of a change in law or interpretation thereof, we or any of our subsidiaries is treated as an association taxable as a corporation or is otherwise subject to additional taxation as an entity for U.S. federal, state, local or non-U.S. income or withholding tax purposes, our general partner may, in its sole discretion, reduce the minimum quarterly distribution and the target distribution levels for each quarter by multiplying each distribution level by a fraction, the numerator of which is cash for that quarter (after deducting our general partner's estimate of our additional aggregate liability for the quarter for such income and withholding taxes payable by reason of such change in law or interpretation) and the denominator of which is the sum of (1) cash for that quarter, plus (2) our general partner's estimate of our additional aggregate liability for the quarter for such income and withholding taxes payable by reason of such change in law or interpretation thereof. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference will be accounted for in distributions with respect to subsequent quarters.

Distributions of Cash Upon Liquidation

General

If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders and the holders of the incentive distribution rights, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

The allocations of gain and loss upon liquidation are intended, to the extent possible, to entitle the holders of units to a repayment of the initial value contributed by unitholders for their units in this offering, which we refer to as the "initial unit price" for each unit. The allocations of gain and loss upon liquidation are also intended, to the extent possible, to entitle the holders of common units to a preference over the holders of subordinated units upon our liquidation, to the extent required to permit common unitholders to receive their initial unit price plus the minimum quarterly distribution for the quarter during which liquidation occurs plus any unpaid arrearages in payment of the minimum quarterly distribution on the common units. However, there may not be sufficient gain upon our liquidation to enable the common unitholders to fully recover all of these amounts, even though there may be cash available for distribution to the holders of subordinated units. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights.

Manner of Adjustments for Gain

The manner of the adjustment for gain is set forth in the partnership agreement. If our liquidation occurs before the end of the subordination period, we will generally allocate any gain to the partners in the following manner:

- *first*, to our general partner to the extent of certain prior losses specially allocated to our general partner;
- *second*, to the common unitholders, pro rata, until the capital account for each common unit is equal to the sum of: (1) the initial unit price; (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs; and (3) any unpaid arrearages in payment of the minimum quarterly distribution;

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- *third*, to the subordinated unitholders, pro rata, until the capital account for each subordinated unit is equal to the sum of: (1) the initial unit price; and (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs;

- *fourth*, to all unitholders, pro rata, until we allocate under this bullet an amount per unit equal to: (1) the sum of the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence; *less* (2) the cumulative amount per unit of any distributions from operating surplus in excess of the minimum quarterly distribution per unit that we distributed to the unitholders, pro rata, for each quarter of our existence;

- *fifth*, 85.0% to all unitholders, pro rata, and 15.0% to the holders of our incentive distribution rights, until we allocate under this bullet an amount per unit equal to: (1) the sum of the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence; *less* (2) the cumulative amount per unit of any distributions from operating surplus in excess of the first target distribution per unit that we distributed 85.0% to the unitholders, pro rata, and 15.0% to the holders of our incentive distribution rights for each quarter of our existence;

- *sixth*, 75.0% to all unitholders, pro rata, and 25.0% to the holders of our incentive distribution rights, until we allocate under this bullet an amount per unit equal to: (1) the sum of the excess of the third target distribution per unit over the second target distribution per unit for each quarter of our existence; *less* (2) the cumulative amount per unit of any distributions from operating surplus in excess of the second target distribution per unit that we distributed 75.0% to the unitholders, pro rata, and 25.0% to the holders of our incentive distribution rights for each quarter of our existence; and

- *thereafter*, 50.0% to all unitholders, pro rata, and 50.0% to holders of our incentive distribution rights.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that clause (3) of the second bullet point above and all of the third bullet point above will no longer be applicable.

We may make special allocations of gain among the partners in a manner to create economic uniformity among the common units into which the subordinated units convert and the common units held by public unitholders.

Manner of Adjustments for Loss

If our liquidation occurs before the end of the subordination period, we will generally allocate any loss to our general partner and the unitholders in the following manner:

- *first*, to holders of subordinated units in proportion to the positive balances in their capital accounts until the capital accounts of the subordinated unitholders have been reduced to zero;

- *second*, to the holders of common units in proportion to the positive balances in their capital accounts, until the capital accounts of the common unitholders have been reduced to zero; and

- *thereafter*, 100.0% to our general partner.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that all of the first bullet point above will no longer be applicable.

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We may make special allocations of loss among the partners in a manner to create economic uniformity among the common units into which the subordinated units convert and the common units held by public unitholders.

Adjustments to Capital Accounts

Our partnership agreement requires that we make adjustments to capital accounts upon the issuance of additional units. In this regard, our partnership agreement specifies that we allocate any unrealized and, for federal income tax purposes, unrecognized gain resulting from the adjustments to the unitholders and the holders of our incentive distribution rights in the same manner as we allocate gain upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional units, our partnership agreement requires that we generally allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon our liquidation in a manner that results, to the extent possible, in the partners' capital account balances equaling the amount that they would have been if no earlier positive adjustments to the capital accounts had been made. In contrast to the allocations of gain, and except as provided above, we generally will allocate any unrealized and unrecognized loss resulting from the adjustments to capital accounts upon the issuance of additional units to the unitholders and the holders of our incentive distribution rights based on their respective percentage ownership of us. In this manner, prior to the end of the subordination period, we generally will allocate any such loss equally with respect to our common and subordinated units. If we make negative adjustments to the capital accounts as a result of such loss, future positive adjustments resulting from the issuance of additional units will be allocated in a manner designed to reverse the prior negative adjustments, and special allocations will be made upon liquidation in a manner that results, to the extent possible, in our unitholders' capital account balances equaling the amounts they would have been if no earlier adjustments for loss had been made.

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SELECTED HISTORICAL AND PRO FORMA FINANCIAL AND OTHER DATA

The following table sets forth our selected historical and pro forma financial and other data, as of the dates and for the periods indicated. The selected historical financial data presented as of August 16, 2013 and for the period from January 1, 2013 to August 16, 2013 have been derived from the audited financial statements of the Predecessor, included elsewhere in this prospectus. The selected historical financial data presented as of December 31, 2013, for the period from August 16, 2013 to December 31, 2013 and as of and for the year ended December 31, 2014 have been derived from the audited financial statements of the Successor, included elsewhere in this prospectus.

The selected historical financial data presented as of and for the three months ended March 31, 2014 and 2015 have been derived from the unaudited interim financial statements of the Successor included elsewhere in this prospectus. The unaudited interim financial statements have been prepared on the same basis as the Successor's audited financial statements and, in the opinion of our management, include all material adjustments, consisting of normal and recurring adjustments, necessary for a fair presentation of the information set forth herein. The selected historical interim balance sheet data as of March 31, 2014 is derived from unaudited interim financial statements of the Successor, which are not included in this prospectus. Operating results for the three months ended March 31, 2015 are not necessarily indicative of the results that may be expected for the year ended December 31, 2015 or for any future period.

The selected unaudited pro forma financial data presented as of and for the year ended December 31, 2014 and the three months ended March 31, 2015 are derived from the unaudited pro forma condensed consolidated financial statements of Bowie Resource Partners LP, included elsewhere in this prospectus. The unaudited pro forma condensed consolidated financial statements of Bowie Resource Partners LP give pro forma effect to the IPO Reorganization described under "Prospectus Summary—IPO Reorganization and Partnership Structure." The unaudited pro forma condensed consolidated balance sheet as of March 31, 2015 reflects the IPO Reorganization as if it occurred on March 31, 2015. The pro forma condensed consolidated statement of (loss) income for the year ended December 31, 2014 and the three months ended March 31, 2015 reflect the IPO Reorganization as if it occurred on January 1, 2014.

We have not given pro forma effect to incremental selling, general and administrative expenses of approximately $ that we expect to incur annually as a result of operating as a publicly traded partnership.

The selected historical and pro forma financial and other data presented below should be read in conjunction with the information presented under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements and related notes thereto appearing in this prospectus.

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	Predecessor	Successor				Bowie Resource Partners LP Pro Forma	
	Year Ended December 31, 2013						
	Period from January 1, 2013 to August 16, 2013	Period from August 16, 2013 to December 31, 2013	Year Ended December 31, 2014	Three Months Ended March 31, 2014	Three Months Ended March 31, 2015	Year Ended December 31, 2014	Three Months Ended March 31, 2015
	(in thousands, except per ton data)						
Statements of Operations Data							
Coal sales	$ 219,140	$ 158,756	$ 419,804	$ 112,265	$ 103,924	$	$
Other revenues, net(1)	813	1,410	358	89	91		
Costs and expenses:							
Cost of coal sales, exclusive of items shown separately below	140,781	96,165	232,819	63,115	61,629		
Transportation	30,477	19,690	44,439	12,758	12,808		
Depreciation, depletion and amortization	21,955	27,251	81,057	18,592	21,334		
Accretion on asset retirement obligations	462	—	785	196	206		
Selling, general and administrative expenses	7,970	9,586	17,590	3,159	4,173		
Amortization of acquired sales contracts, net	—	3,708	12,098	3,181	(54)		
Operating income	18,308	3,766	31,374	11,353	3,919		
Other expenses (income):							
Interest expense and related financing costs	—	13,604	36,245	9,093	8,021		
Gain on sale of assets	(389)	—	—	—	—		
Other	769	—	—	—	—		
Net income (loss)	$ 17,928	$ (9,838)	$ (4,871)	$ 2,260	$ (4,102)	$	$
Cash Flow Data							
Net cash provided by operating activities	$ 45,964	$ 14,858	$ 84,524	$ 12,941	$ 5,454		
Net cash used in investing activities	$ (5,217)	$ (8,373)	$ (27,044)	$ (1,119)	$ (5,960)		
Net cash (used in) provided by financing activities	$ (40,807)	$ (6,485)	$ (57,480)	$ (11,822)	$ 506		
Balance Sheet Data (at period end)							
Total current assets	$ 51,857	$ 82,093	$ 84,655	$ 80,907	$ 93,375		$
Property, plant and equipment, net	$ 285,934	$ 400,945	$ 357,110	$ 385,612	$ 344,557		$
Other assets	$ 5,192	$ 36,615	$ 17,659	$ 36,701	$ 16,203		$

Total liabilities	$	51,430	$	495,027	$	440,104	$	480,497	$	446,069		$
Member's equity	$	291,553	$	24,626	$	19,320	$	22,723	$	8,066		$
Total liabilities and member's equity	$	342,983	$	519,653	$	459,424	$	503,220	$	454,135		$
Other Data												
EBITDA(2)	$	39,883	$	34,725	$	124,529	$	33,126	$	25,199	$	$
Adjusted EBITDA(2)	$	40,725	$	34,725	$	125,314	$	33,322	$	25,405	$	$
Tons produced		5,793		3,863		11,386		2,935		2,518		
Tons sold		5,614		4,440		11,463		3,175		2,691		
Coal sales realized per ton(3)	$	39.03	$	35.76	$	36.62	$	35.36	$	38.62	$	$
Direct mining costs per ton(4)	$	25.08	$	21.66	$	20.31	$	19.88	$	22.90	$	$

(1) Primarily includes net revenues from contract terminations (bookouts), restructuring payments, royalties related to coal lease agreements and revenues from property and facility rentals.

(2) Please read "—Non-GAAP Financial Measures" below for the definitions of EBITDA and Adjusted EBITDA and a reconciliation of EBITDA and Adjusted EBITDA to our most directly comparable financial measure, calculated and presented in accordance with GAAP.

(3) Coal sales realized per ton is defined as coal sales divided by tons sold.

(4) Direct mining costs per ton is defined as cost of coal sales, exclusive of items shown separately, divided by tons sold.

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Non-GAAP Financial Measures

EBITDA and Adjusted EBITDA are non-GAAP financial measures used by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others to assess:

- our ability to make distributions to our unitholders;
- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate sufficient cash to pay interest costs and support our indebtedness;
- our operating performance and return on capital as compared to those of other companies and partnerships in our industry, without regard to financing or capital structure; and
- the feasibility of acquisitions and other capital expenditures and the overall rates of return on investment opportunities.

We define EBITDA as net income (loss) before interest expense, income tax, depreciation, depletion and amortization. We define Adjusted EBITDA as EBITDA further adjusted for accretion of asset retirement obligations, gain or loss on sale of assets, casualty losses and other taxes.

EBITDA and Adjusted EBITDA should not be considered alternatives to, or more meaningful than, net income (loss), income from operations, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP as measures of our operating performance or liquidity. EBITDA and Adjusted EBITDA do not include changes in working capital, capital expenditures and other items that are set forth in cash flow statement presentation of our operating, investing and financing activities. Any measures that exclude these elements have material limitations. Our computations of EBITDA and Adjusted EBITDA may differ from computations of similarly titled measures of other companies.

The following table presents a reconciliation of EBITDA and Adjusted EBITDA to the most directly comparable GAAP financial measure for the periods indicated.

	Predecessor	Successor				Bowie Resource Partners LP Pro Forma	
	Year Ended December 31, 2013						
	Period from January 1, 2013 to August 16, 2013	Period from August 16, 2013 to December 31, 2013	Year Ended December 31, 2014	Three Months Ended March 31, 2014	Three Months Ended March 31, 2015	Year Ended December 31, 2014	Three Months Ended March 31, 2015
	(in thousands)						
Reconciliation of EBITDA and Adjusted EBITDA to Net income (loss):							
Net income (loss)	$ 17,928	$ (9,838)	$ (4,871)	$ 2,260	$ (4,102)	$	$
Add:							
Depreciation, depletion and amortization	21,955	27,251	81,057	18,592	21,334		
Amortization of acquired sales contracts, net	—	3,708	12,098	3,181	(54)		
Interest expense and related financing costs	—	13,604	36,245	9,093	8,021		
EBITDA	39,883	34,725	124,529	33,126	25,199		
Add:							
Accretion on asset retirement obligations	462	—	785	196	206		
Gain on sale of assets	(389)	—	—	—	—		
Other	769	—	—	—	—		

Adjusted EBITDA	$ 40,725	$ 34,725	$ 125,314	$ 33,322	$ 25,405	$	$

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion and analysis together with "Selected Historical and Pro Forma Financial and Other Data" and the financial statements and related notes included elsewhere in this prospectus.

The following discussion and analysis of our historical financial condition and results of operations as of August 16, 2013 and for the period from January 1, 2013 to August 16, 2013 (the "2013 Predecessor Period") has been derived from the audited financial statements of Canyon Fuel Company, LLC ("CFC") prior to the acquisition of CFC by our sponsor on August 16, 2013 (the "Predecessor"), included elsewhere in this prospectus. The discussion and analysis of our historical financial condition and results of operations as of December 31, 2013, for the period from August 16, 2013 to December 31, 2013 (the "2013 Successor Period") and as of and for the year ended December 31, 2014 has been derived from the audited financial statements of CFC after the acquisition of CFC by our sponsor (the "Successor"), included elsewhere in this prospectus.

The discussion and analysis of our historical financial condition and results of operations as of and for the three months ended March 31, 2014 and 2015 have been derived from the unaudited interim financial statements of the Successor included elsewhere in this prospectus. The unaudited interim financial statements have been prepared on the same basis as the Successor's audited financial statements and, in the opinion of our management, include all material adjustments, consisting of normal and recurring adjustments, necessary for a fair presentation of the information set forth herein. The historical interim balance sheet data as of March 31, 2014 have been derived from unaudited interim financial statements of the Successor, which are not included in this prospectus. Operating results for the three months ended March 31, 2015 are not necessarily indicative of the results that may be expected for the year ended December 31, 2015 or for any future period.

Unless otherwise indicated, references in "Management's Discussion and Analysis of Financial Condition and Results of Operations" to "the partnership," "we," "our," "us" or like terms when used in a historical context refer to the business and financial condition and results of operations of CFC and its subsidiaries, and when used in the present tense or prospectively, refer to Bowie Resource Partners LP and its subsidiaries giving effect to the transactions described in "Prospectus Summary—IPO Reorganization and Partnership Structure."

This discussion contains forward-looking statements about our business, operations and industry that involve risks and uncertainties, such as statements regarding our plans, objectives, expectations and intentions. Our future results and financial condition may differ materially from those we currently anticipate as a result of the factors we describe under "Forward-Looking Statements," "Risk Factors" and elsewhere in this prospectus. All references to tons produced, tons sold, coal sales realized per ton or direct mining costs per ton refer to clean tons of coal.

Overview

We operate three low-cost, underground coal mines in the Uinta Basin that produce high Btu, low sulfur coal that is sold both domestically and internationally. Our mines consist of:

- *Sufco:* A longwall mine in southern Utah, producing coal with one longwall mining system and three continuous miner units, with a productive capacity of approximately 7.0 million tons per year.
- *Skyline:* A longwall mine in central Utah, producing coal with one longwall mining system and two continuous miner units, with a productive capacity of approximately 4.5 million tons per year.

- *Dugout Canyon:* A continuous miner operation in central Utah, which as of January 2015 is producing coal with two continuous miners, with a productive capacity of approximately 1.1 million tons per year. We believe our Dugout Canyon mine can support an additional continuous miner unit without any additional surface infrastructure, which would increase its productive capacity to approximately 1.5 million tons per year.

We have significantly enhanced the performance of our mines since they were acquired by our sponsor in August 2013. Coal production at our mines increased from 5.8 million tons and 3.9 million tons for the 2013 Predecessor Period and 2013 Successor Period, respectively, to 11.4 million tons for the year ended December 31, 2014. During the year ended December 31, 2014, we realized net loss, operating income and Adjusted EBITDA of $4.9 million, $31.4 million and $125.3 million, respectively, as compared to net income, operating income and Adjusted EBITDA of $17.9 million, $18.3 million and $40.7 million, respectively, for the 2013 Predecessor Period and net loss, operating income and Adjusted EBITDA of $9.8 million, $3.8 million and $34.7 million, respectively, for the 2013 Successor Period. Please read "Prospectus Summary—Summary Historical and Pro Forma Financial and Other Data—Non-GAAP Financial Measures" for the definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our most directly comparable financial measure calculated and presented in accordance with GAAP.

Our results for the three months ended March 31, 2015 as compared to the three months ended March 31, 2014 were affected by a scheduled 20-day longwall move at our Sufco mine during 2015 that did not occur in 2014, partially offset by increased coal sales realized per ton. As a result of this scheduled longwall move, coal production decreased from 2.9 million tons for the three months ended March 31, 2014 to 2.5 million tons for the three months ended March 31, 2015. In addition, coal sales realized per ton increased 9% from $35.36 for the three months ended March 31, 2014 to $38.62 for the three months ended March 31, 2015, primarily driven by price escalators in our existing coal supply agreements and a change in sales mix reflecting lower export sales that are generally sold at a lower realized price FOB the mine.

On June 5, 2015, we acquired from PacifiCorp and its affiliate (a) certain undeveloped, high Btu, low sulfur coal reserves in Utah (the "Fossil Rock reserves") through our wholly-owned subsidiary, Fossil Rock Resources, LLC and (b) certain real property near PacifiCorp's Hunter Power Plant through our wholly-owned subsidiary Hunter Prep Plant, LLC (the "Utah Transaction") for a purchase price of $40.0 million (including (i) a $30 million promissory note from Fossil Rock Resources, LLC and (ii) a $10 million promissory note from Hunter Prep Plant, LLC, each of which we expect to repay using net proceeds from this offering and the offering of New Notes). As part of the Utah Transaction, our sponsor entered into an agreement with PacifiCorp to supply all of the coal requirements of PacifiCorp's Huntington Power Plant in Utah through 2029. The volume for the new coal supply agreement with PacifiCorp will be supplied predominantly with our coal. The Fossil Rock reserves increase our proven and probable reserves by an estimated 11.2 million tons and 32.5 million tons, respectively, and provide a natural replacement for the low sulfur coal currently produced by our Sufco mine from the Upper Hiawatha seam, which we expect to be exhausted in the third quarter of 2021.

We believe we are uniquely positioned with our low-cost coal, long-term domestic coal supply agreements and terminal agreements to provide attractive returns and grow our business both organically and through acquisitions. The timing of additional development and/or acquisitions is dependent on several factors, including permitting, market demand, access to capital, equipment availability and the committed sales position at our existing mining operations.

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Factors That Affect Our Results, Trends and Uncertainties

Contract Position

We sell a significant portion of our coal under coal supply agreements with terms that range from one to fifteen years. On a pro forma basis, after giving effect to the closing of the Utah Transaction, we expect coal sales under our existing coal supply agreements of approximately 11.2 million tons in 2015, 9.0 million tons in 2016, 9.5 million tons in 2017 and 9.3 million tons in 2018, which represent approximately 100%, 82%, 86% and 84%, respectively, of our production for the twelve months ended March 31, 2015. We have sold coal to 68 domestic power plants, industrial users and international customers. However, the three primary power plants that purchase our coal are located in Utah and are a short truck or rail haul from our mines. Export tons are sold to customers in multiple countries throughout the Pacific Rim, principally by Trafigura AG, the exclusive marketer of our uncommitted coal. Trafigura AG, along with its affiliates, has 45 offices in 36 countries around the world and is a leading independent commodity trader. To date, we absorb no foreign credit risk as all tons are sold FOB the U.S. port.

Our primary sales strategy is to enter into long-term domestic coal supply agreements for the majority of our production with fixed pricing, subject to certain price escalators and adjustments. Please read "Business—Customers." Our coal sales realized per ton in the near term may decrease as we replace expiring favorably priced coal supply agreements with new coal supply agreements at contractually negotiated market prices.

Coal Prices

Generally, domestic coal prices have weakened since 2011 due to reduced demand from coal-fired power plants. International coal prices have also declined as a result of excess supply in the marketplace. According to globalCOAL, the Newcastle spot price of coal FOB Australia declined from $114.30 per metric ton at January 6, 2012, to $94.16 per metric ton at January 4, 2013, to $85.41 per metric ton at January 3, 2014, to $61.94 per metric ton at January 2, 2015 and to $59.60 per metric ton at March 27, 2015. We expect this low-price environment to continue into the second half of 2015. Price trends thereafter are likely to be influenced by supply and demand balance, production and transportation costs, availability of alternate fuels, macroeconomic conditions, coal quality, governmental regulation and weather patterns. We attempt to mitigate coal price fluctuations by executing long-term coal supply agreements and may hedge a portion of our unpriced export position. We have four long-term coal supply agreements (two with PacifiCorp and two with IPA) that provide both volume and pricing visibility through calendar year 2020, accounting for approximately 9.0 million tons per year of coal sales, or about 71% of our productive capacity as of December 31, 2014. Beyond 2020, these same agreements provide volume and pricing certainty through 2024 for approximately 4.5 million tons per year, or approximately 36% of our productive capacity as of December 31, 2014. Please read "The Coal Industry—Coal Pricing" for further discussion of pricing trends and expectations.

Coal Demand

Demand for coal can increase due to unusually hot or cold weather as electricity consumers use more air conditioning or heating and, as a result, power producers burn more coal. Conversely, mild weather can result in lower demand for our coal. Adverse weather conditions, such as blizzards or floods, can affect our ability to mine and ship our coal and our customers' ability to take delivery of coal. Coal demand in the western United States is also impacted by rain and the winter snow pack since coal fired power generation competes with hydro-electric power production. Generally, our customers take deliveries ratably throughout the year building or depleting their inventory.

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While global coal prices have declined in recent years, and we expect U.S. coal export demand to be slightly weaker in the near term, we expect long-term international demand for thermal coal to increase, supported by emerging economies across the globe and sustained growth in electric power generation and steel production capacity in Asia, most noticeably in China and India. Imports by China are expected to grow by 108% to 419.1 million metric tons from 2014 to 2035, according to Wood Mackenzie. As a result of growing international demand, coal prices for seaborne thermal coal have, from time to time, been higher relative to domestic prices. Based on forward price curves, we expect seaborne thermal coal prices to continue to increase over time. Given our low cost of production, attractive coal qualities, transportation optionality, and unique access to U.S. West Coast terminals, we believe we will be competitive selling our coal into the seaborne market in the future. Please read "The Coal Industry—Coal Demand" for further discussion of coal demand trends and expectations.

Coal Tons Produced

The table below represents total tons produced from our mines:

	Predecessor	Successor			
	Year Ended December 31, 2013				
	Period from January 1, 2013 to August 16, 2013	Period from August 16, 2013 to December 31, 2013	Year Ended December 31, 2014	Three Months Ended March 31, 2014	Three Months Ended March 31, 2015
		(in thousands)			
Tons produced	5,793	3,863	11,386	2,935	2,518

Our production may be influenced by geological conditions, delays in obtaining permits or leases, labor shortages, unforeseen equipment problems and unexpected shortages of critical materials, such as steel, diesel fuel and explosives, that may result in adverse cost increases and limit our ability to produce at our forecasted levels. Please read "Risk Factors" for further discussion of risks and uncertainties that may affect our production.

Longwall Moves

Longwall mines have periods of interrupted production as mining is completed in a particular panel and the longwall mining equipment is disassembled, moved and reassembled at the next panel. During these periods, the mine continues to ship coal to customers from continuous miner production and/or inventory as available. We attempt to minimize this production interruption by designing long and wide panels that limit moves to approximately twice per year. Production interruptions of 20 days or less occur with a frequency of six to nine months. There are no guarantees that future longwall moves at our longwall mines will have similar results.

Cost of Coal Sales, Exclusive of Items Shown Separately

Our cost of coal sales, exclusive of items shown separately, includes labor and benefits, supplies, repairs, utilities, insurance, equipment rental, mine lease costs, property and land subsidence costs, sales-related costs, belting, coal preparation, royalties and direct mine overhead. Each of these cost components has its own drivers, which can include the cost and availability of labor, changes in health care and insurance regulations, the cost of consumable items or inputs in our supplies, changes in regulation, and/or our staffing levels. In particular, our royalties can depend directly upon the price at which we sell our coal and the underlying terms of our coal leases.

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Transportation

We sell a majority of our coal to customers at delivery points other than our mines, including power plants, industrial facilities and ports along the U.S. West Coast. As such, we often bear the transportation costs and any transloading costs. Where possible, we enter into long-term transportation and throughput agreements. Because we are responsible for the cost of transporting our coal to these various delivery points, we often, but not always, bear the risk that our transportation expense will increase over time. Our transportation costs, in part, correlate to the distance required to transport our coal to the buyer. As a result, the transportation of our coal to domestic buyers has lower associated costs than the transportation of our coal to international buyers. International sales require us to transport coal first by rail to a seaborne export terminal and then load the coal onto the buyers' ships. In certain circumstances, the cost of transporting our coal to international buyers can be as much as ten times the cost of transporting our coal to domestic buyers.

Depreciation, Depletion and Amortization

Costs of mineral rights and developing new mines or significantly expanding the capacity of existing mines are capitalized and amortized using the units of production method, based on estimated proven and probable reserves. Property, plant and equipment are recorded at cost and are generally expensed on a straight-line basis over the useful life of the asset. Costs that extend the useful life or increase the productivity of the assets are capitalized, while normal repairs and maintenance are expensed as incurred. Interest costs applicable to major additions are capitalized during the construction period.

Accretion on Asset Retirement Obligations

Accretion expense represents the increase in the carrying amount of our asset retirement obligations due to the passage of time.

Selling, General and Administrative

Selling, general and administrative expense consists of our general corporate overhead expenses, including management and administrative labor, corporate occupancy expenses, office expenses, and professional fees.

Regulatory Environment

A variety of actions taken by regulatory agencies, including climate change regulation, challenges to the issuance or renewal of our permits to operate, and challenges to the issuance of BLM leases, could substantially increase compliance costs for us and our customers, reduce general demand for coal, or interrupt operations at one or more of our mines.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources is based on our financial statements, which have been prepared in accordance with GAAP. GAAP requires that we make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and the related disclosure of contingent assets and liabilities. We base these estimates on historical experience and on various other assumptions that we consider reasonable under the circumstances. On an ongoing basis we evaluate our estimates. Actual results may differ from

these estimates. Of these significant accounting policies, we believe the following may involve a higher degree of judgment or complexity:

Revenue Recognition

Our revenues are generated primarily under long-term coal supply agreements with electric utilities, industrial companies and coal brokers that in turn sell coal domestically or internationally. Revenue is recognized when title or risk of loss passes to the customer. Title passes generally when the coal is loaded on the rail, ocean vessel or other transportation source that delivers the coal to its destination.

Other revenues primarily include net revenues from contract termination (bookouts) or restructuring payments incurred during the period. Also included are revenues from royalties related to coal lease agreements and revenues from property and facility rentals.

Segment Information

We operate as a single reportable segment, as our Chief Executive Officer, serving as our Chief Operating Decision Maker (CODM), reviews financial information on the basis of our consolidated financial results for purposes of making decisions. Generally, the CODM evaluates performance and allocates resources based on Adjusted EBITDA. Discrete financial information sufficient to allow the CODM to make decisions is only available on a consolidated basis.

Acquired Sales Contracts

Coal supply agreements (sales contracts) acquired in business combinations are capitalized at their fair value and amortized over the tons of coal shipped during the contract. The fair value of a sales contract is determined by discounting the cash flows attributable to the difference between the contract price and the prevailing forward prices for the tons remaining under the contract at the date of acquisition. Contracts where the expected contract price is above market at the acquisition date have a positive value and are classified as assets, whereas contracts where the expected contract price is below market at the acquisition date have a negative value and are classified as liabilities. If a contract is terminated before it has been fully amortized, the remaining fair value of the acquired contract is written off and recognized as a gain (below market contracts) or loss (above market contracts) on contract termination.

Inventory

Coal, parts and supply inventories are valued at the lower of average cost or market. Coal inventory costs include labor, parts and supplies used, equipment costs, transportation costs prior to title transfer to customers, depreciation, depletion, amortization and operating overhead. Coal is classified as inventory at the time the coal is extracted and transported to the mine surface.

Property, Plant and Equipment

Property, plant and equipment are stated at cost, except for assets acquired using purchase accounting, which are recorded at fair value at the date of acquisition. Additions and improvements that significantly add to productive capacity or extend the useful life of assets are capitalized. Interest costs applicable to major asset additions are capitalized during the construction period. Maintenance and repair costs are expensed as incurred. Depreciation is recorded using the straight-line method over the estimated useful lives of the assets. The useful lives of our equipment, plant and facilities generally range from 5 to 10 years with the exception of buildings which have a 20 year useful life.

Mineral rights and mine development costs, which are included with property, plant and equipment, are recorded at cost, except for assets acquired using purchase accounting, which are

recorded at fair value at the date of acquisition. Depletion of reserves and amortization of mine development costs are computed using the units of production method, based on estimated proven and probable reserves. If coal is extracted during the mine development process, the amount of revenue from the sale of that coal is included in other income in the period earned.

Long-lived assets, such as property, equipment, mine development costs, owned and leased mineral rights and purchased intangibles subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or asset groups may not be recoverable. Recoverability of assets or asset groups to be held and used is measured by a comparison of the carrying amount of an asset or asset group to the estimated undiscounted future cash flows expected to be generated by the asset or asset group. If the carrying amount of an asset or asset group exceeds its estimated future cash flows, an impairment charge is recognized equal to the amount by which the carrying amount of the asset or asset group exceeds the fair value of the asset or asset group.

Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. For our active mining operations, we generally group such assets at the mine level, with the exception of impairment evaluations triggered by mine closures. In those cases involving mine closures, the related assets are evaluated at the individual asset level for remaining economic life based on transferability to our other ongoing operations and for use in reclamation activities, or for expected salvage value. For our development properties and portfolio of surface land and coal reserve holdings, we consider several factors to determine whether to evaluate those assets individually or on a grouped basis for purposes of impairment testing. Such factors include geographic proximity to one another, the expectation of shared infrastructure upon development based on future mining plans and whether it would be most advantageous to bundle such assets in the event of sale to a third party.

Asset Retirement Obligations

Our asset retirement obligations ("ARO") liabilities consist of cost estimates for reclamation and support facilities at our mines in accordance with interpretations of applicable federal and state reclamation laws, as defined by each mining permit. These cost estimates relate to reclaiming support acreage, sealing portals at deep mines and other costs related to reclaiming refuse areas.

We estimate our ARO liabilities for final reclamation and mine closure based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Cost estimates are escalated for inflation and then discounted at the credit-adjusted, risk-free rate (9% at December 31, 2014 and 2013). Accretion on the ARO begins at the time the liability is incurred. Upon initial recognition of a liability, a corresponding amount is capitalized as part of the carrying amount of the related long-lived asset. The ARO asset is amortized over its expected life on a units-of-production basis. The ARO liability is then accreted to the projected spending date. As changes in estimates occur (such as mine plan revisions, changes in estimated costs, or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free rate. We review our ARO at least annually and make necessary adjustments for permit changes as granted by state authorities and for revisions of estimates of the amount and timing of costs. Any difference between the recorded obligation and the actual cost of reclamation is recorded in profit or loss in the period the obligation is settled.

Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Valuation techniques used must maximize the use of observable inputs and minimize the use of unobservable inputs.

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A three level hierarchy has been established for valuing assets and liabilities based on how transparent (observable) the inputs are that are used to determine fair value, with the inputs considered most observable categorized as Level 1 and those that are least observable categorized as Level 3. Hierarchy levels are defined below:

- Level 1: Quoted prices in active markets for identical assets and liabilities;
- Level 2: Quoted prices for similar assets and liabilities in active markets; quoted prices for identical or similar instruments in markets that are not active; and
- Level 3: Unobservable inputs that are supported by little or no market data which require the reporting entity to develop its own assumptions.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of assets and liabilities and their placement within fair value hierarchy levels.

Our accounts receivable, restricted cash, accounts payable and accrued expenses are considered financial instruments. These assets and liabilities are reflected at fair value or at carrying amounts that approximate their fair value due to the short-term nature or the terms of the instruments. The estimated carrying value of our debt approximates its fair value because the effective interest rates are not significantly different from current market rates. We do not have any nonfinancial assets or nonfinancial liabilities measured at fair value on a recurring basis, other than ARO. The inputs and techniques used to derive ARO fair value are described in the ARO section above. This fair value determination is classified as Level 3 in the hierarchy.

We measure the fair value of certain assets on a non-recurring basis, generally when events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. Our policy is further described in the property, plant and equipment policies above.

Key Metrics

We assess the performance of our business using certain key metrics. These key metrics include tons produced, tons sold, coal sales realized per ton, direct mining costs per ton and Adjusted EBITDA.

Tons produced is defined as clean tons produced.

Tons sold is defined as produced and purchased tons sold (as applicable).

Coal sales realized per ton is defined as coal sales divided by tons sold.

Direct mining costs per ton is defined as cost of coal sales, exclusive of items shown separately, divided by tons sold.

EBITDA and Adjusted EBITDA are non-GAAP financial measures used by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others to assess:

- our ability to make distributions to our unitholders;
- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate sufficient cash to pay interest costs and support our indebtedness;
- our operating performance and return on capital as compared to those of other companies and partnerships in our industry, without regard to financing or capital structure; and

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- the feasibility of acquisitions and other capital expenditures and the overall rates of return on investment opportunities.

We define EBITDA as net income (loss) before interest expense, income tax, depreciation, depletion and amortization. We define Adjusted EBITDA as EBITDA further adjusted for accretion of asset retirement obligations, gain or loss on sale of assets, casualty losses and other taxes.

EBITDA and Adjusted EBITDA should not be considered alternatives to, or more meaningful than, net income (loss), income from operations, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP as measures of our operating performance or liquidity. EBITDA and Adjusted EBITDA do not include changes in working capital, capital expenditures and other items that are set forth in cash flow statement presentation of our operating, investing and financing activities. Any measures that exclude these elements have material limitations. Our computations of EBITDA and Adjusted EBITDA may differ from computations of similarly titled measures of other companies. Please read "Selected Historical and Pro Forma Financial and Other Data—Non-GAAP Financial Measures" for a reconciliation of EBITDA and Adjusted EBITDA to our most directly comparable financial measure, calculated and presented in accordance with GAAP.

Factors Affecting Comparability of Financial Results

Our historical results of operations and cash flows are not indicative of results of operations and cash flows to be expected in the future principally for the following reasons:

Long-Term Debt

In connection with the closing of this offering, we expect that CFC will be released as a guarantor under our sponsor's Senior Secured Credit Facilities, and that the liens on the assets being contributed to us and securing borrowings under these facilities will be released. Prior to this offering, Finance Corp. issued $ million aggregate principal amount of % senior secured notes due . From and after the satisfaction of the Escrow Release Conditions, which we expect to occur concurrently with the closing of this offering, the partnership will become a co-issuer of the New Notes and a party to the indenture governing the New Notes. In connection with the closing of this offering we also expect to enter into a new $ million revolving credit facility. We expect to use net proceeds from this offering and our offering of the New Notes to repay the outstanding Prudential Notes and the PacifiCorp Notes. Please read "—Liquidity and Capital Resources—Long-Term Debt."

Public Company Expenses

We estimate that we will incur approximately $ million of incremental selling, general and administrative expenses per year associated with being a publicly traded partnership, consisting of expenses associated with SEC reporting requirements, including annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, Sarbanes-Oxley Act compliance, listing fees, independent auditor fees, legal fees, investor relations activities, registrar and transfer agent fees, director and officer insurance and director compensation.

CFC Acquisition

Our sponsor acquired CFC on August 16, 2013. The 2013 Successor Period includes the effect of fair value purchase accounting adjustments resulting from the acquisition of CFC by our sponsor. Due to the change in the basis of accounting resulting from the application of purchase accounting, the Predecessor's historical financial data and the Successor's historical financial data are not necessarily comparable.

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Results of Operations

The table below displays our results of operations for the periods indicated.

	Predecessor	Successor			
	Year Ended December 31, 2013				
	Period from January 1, 2013 to August 16, 2013	Period from August 16, 2013 to December 31, 2013	Year Ended December 31, 2014	Three Months Ended March 31, 2014	Three Months Ended March 31, 2015
	(in thousands, except per ton data)				
Statements of Operations Data					
Coal sales	$ 219,140	$ 158,756	$ 419,804	$ 112,265	$ 103,924
Other revenues, net	813	1,410	358	89	91
Costs and expenses:					
Cost of coal sales, exclusive of items shown separately below	140,781	96,165	232,819	63,115	61,629
Transportation	30,477	19,690	44,439	12,758	12,808
Depreciation, depletion and amortization(1)	21,955	27,251	81,057	18,592	21,334
Accretion on asset retirement obligations	462	—	785	196	206
Selling, general and administrative expenses	7,970	9,586	17,590	3,159	4,173
Amortization of acquired sales contracts, net	—	3,708	12,098	3,181	(54)
Operating income	18,308	3,766	31,374	11,353	3,919
Other expenses (income):					
Interest expense and related financing costs(2)	—	13,604	36,245	9,093	8,021
Gain on sale of assets	(389)	—	—	—	—
Other	769	—	—	—	—
Net income (loss)	$ 17,928	$ (9,838)	$ (4,871)	$ 2,260	$ (4,102)
Other Data					
EBITDA(3)	$ 39,883	$ 34,725	$ 124,529	$ 33,126	$ 25,199
Adjusted EBITDA(3)	$ 40,725	$ 34,725	$ 125,314	$ 33,322	$ 25,405
Tons produced	5,793	3,863	11,386	2,935	2,518
Tons sold	5,614	4,440	11,463	3,175	2,691
Coal sales realized per ton(4)	$ 39.03	$ 35.76	$ 36.62	$ 35.36	$ 38.62
Direct mining costs per ton(5)	$ 25.08	$ 21.66	$ 20.31	$ 19.88	$ 22.90

(1) The increase in depreciation, depletion and amortization is primarily the result of the step-up in basis of our coal properties and supporting mine infrastructure upon the acquisition of CFC by our sponsor.

(2) Interest expense increased as the result of our sponsor borrowing $435 million to acquire CFC.

(3) Please read "Selected Historical and Pro Forma Financial and Other Data—Non-GAAP Financial Measures" for the definitions of EBITDA and Adjusted EBITDA and a reconciliation of EBITDA and Adjusted EBITDA to our most directly comparable financial measure, calculated and presented in accordance with GAAP.

(4) Coal sales realized per ton is defined as coal sales divided by tons sold.

(5) Direct mining costs per ton is defined as cost of coal sales, exclusive of items shown separately, divided by tons sold.

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Comparison of Three Months Ended March 31, 2015 to Three Months Ended March 31, 2014

Overview

Our results for the three months ended March 31, 2015 as compared to the three months ended March 31, 2014 were affected by a scheduled 20-day longwall move at our Sufco mine during 2015 that did not occur in 2014, partially offset by increased coal sales realized per ton. As a result of the scheduled longwall move, coal production decreased from 2.9 million tons for the three months ended March 31, 2014 to 2.5 million tons for the three months ended March 31, 2015. In addition, coal sales realized per ton increased 9% from $35.36 for the three months ended March 31, 2014 to $38.62 for the three months ended March 31, 2015. The increase in realization is primarily due to price escalators in our existing coal supply agreements and a change in sales mix reflecting lower export sales that are generally sold at a lower realized price FOB the mine. Our direct mining costs per ton increased from $19.88 for the three months ended March 31, 2014 to $22.90 for the three months ended March 31, 2015 due primarily to the scheduled longwall move at our Sufco mine.

Coal Sales

The following table summarizes coal sales information for the three months ended March 31, 2015 and 2014:

	Successor			
	Three Months Ended March 31, 2014	Three Months Ended March 31, 2015	Increase/ (Decrease) $	Increase/ (Decrease) %
	(in thousands, except per ton data)			
Coal sales	$ 112,265	$ 103,924	$ (8,341)	(7)%
Tons sold	3,175	2,691	(484)	(15)%
Coal sales realized per ton(4)	$ 35.36	$ 38.62	$ 3.26	9%

Coal sales for the three months ended March 31, 2015 were $103.9 million compared to coal sales of $112.3 million for the three months ended March 31, 2014. The decrease in coal sales was due to a 0.5 million ton decrease in sales volumes reflecting lower export shipments for the period, partially offset by a 9% increase in coal sales realized per ton as compared to the three months ended March 31, 2014, which was primarily driven by contractual price escalators and lower export shipments. The export sales mix decreased to 8% of tons sold during the three months ended March 31, 2015 versus 21% during the three months ended March 31, 2014.

Other Revenues, Net

Other revenues, net remained consistent at $0.1 million for both the three months ended March 31, 2015 and 2014.

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Cost of Coal Sales, Exclusive of Items Shown Separately

The following table summarizes cost of coal sales, exclusive of items shown separately, for the three months ended March 31, 2015 and 2014:

	Successor			
	Three Months Ended March 31, 2014	Three Months Ended March 31, 2015	Increase/ (Decrease) $	Increase/ (Decrease) %
	(in thousands, except per ton data)			
Cost of coal sales, exclusive of items shown separately	63,115	61,629	(1,486)	(2)%
Tons sold	3,175	2,691	(484)	(15)%
Direct mining costs per ton(1)	$ 19.88	$ 22.90	$ 3.02	15%
Tons produced	2,935	2,518	(417)	(14)%

(1) Direct mining costs per ton is defined as cost of coal sales, exclusive of items shown separately, divided by tons sold.

Cost of coal sales, exclusive of items shown separately, for the three months ended March 31, 2015 decreased to $61.6 million compared to $63.1 million for the three months ended March 31, 2014. Our direct mining costs per ton increased from $19.88 for the three months ended March 31, 2014 to $22.90 for the three months ended March 31, 2015. Both changes were primarily driven by the scheduled longwall move at our Sufco mine, which reduced tons produced and in turn impacted our cost per ton.

Transportation

Transportation expenses remained relatively consistent at $12.8 million for the three months ended March 31, 2015 and 2014, as decreased sales at our Sufco mine due to the scheduled longwall move were fully offset by increased coal sales under the new 15-year coal supply agreement with PacifiCorp for delivery to the Huntington Power Plant that was supplied via truck from our Skyline mine.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization expenses for the year ended March 31, 2015 were $21.3 million compared to $18.6 million for the three months ended March 31, 2014. This increase is primarily driven by amortization of capitalized longwall costs of $2.8 million for the three months ended March 31, 2015 as compared to none for the three months ended March 31, 2014.

Amortization of Acquired Sales Contracts

Amortization of acquired sales contracts for the three months ended March 31, 2015 were $(0.1) million compared to $3.1 million for the three months ended March 31, 2014. This decrease reflects the declining balance of the intangible asset being amortized as the acquired contracts reach the end of their terms.

Selling, General and Administrative

Selling, general and administrative expenses for the three months ended March 31, 2015 were $4.2 million compared to $3.2 million for the three months ended March 31, 2014. This increase is primarily driven by increased personnel and legal costs associated with this offering.

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Interest Expense, Net

Interest expense, net for the three months ended March 31, 2015 was $8.0 million compared to $9.1 million for the three months ended March 31, 2014. Interest expense decreased primarily due to principal debt payments.

Net Income (Loss)

We realized a net loss of $4.1 million for the three months ended March 31, 2015 compared to net income of $2.3 million for the three months ended March 31, 2014. This decrease was primarily due to the following: (i) decreased coal sales of $8.4 million, (ii) increased depreciation, depletion and amortization of $2.7 million, and (iii) increased selling, general and administrative expenses of $1.0 million, partially offset by (i) decreased amortization of acquired sales contracts of $3.2 million, (ii) decreased cost of coal sales, exclusive of items shown separately, of $1.5 million, and (iii) decreased interest expense of $1.1 million.

Adjusted EBITDA

We realized Adjusted EBITDA of $25.4 million for the three months ended March 31, 2015 compared to $33.3 million for the three months ended March 31, 2014. This decrease was primarily due to decreased coal sales of $8.4 million and increased selling, general and administrative expenses of $1.0 million, offset in part by decreased cost of coal sales of $1.5 million.

Comparison of Year Ended December 31, 2014 to the 2013 Predecessor Period and the 2013 Successor Period

Overview

Our mines sold 11.5 million tons of coal during the year ended December 31, 2014 compared to 5.6 million tons and 4.4 million tons in the 2013 Predecessor Period and the 2013 Successor Period, respectively. Our coal sales realized per ton during 2014 decreased 6.2%, or $2.41 per ton, when compared to the 2013 Predecessor Period and increased 2.4%, or $0.86 per ton, when compared to the 2013 Successor Period. The decrease from the 2013 Predecessor Period is primarily due to (i) pricing declines, as favorably priced coal supply agreements expired and were replaced with new coal supply agreements, (ii) an increase in the percentage of sales at lower export prices and (iii) spot sales at lower market prices. Our direct mining costs per ton during 2014 decreased 19.0%, or $4.77 per ton, when compared to the 2013 Predecessor Period and decreased 6.2%, or $1.35 per ton, when compared to the 2013 Successor Period. During the year ended December 31, 2014, we realized net loss, operating income and Adjusted EBITDA of $4.9 million, $31.4 million and $125.3 million, respectively, as compared to net income, operating income and Adjusted EBITDA of $17.9 million, $18.3 million and $40.7 million, respectively, for the 2013 Predecessor Period and net loss, operating income and Adjusted EBITDA of $9.8 million, $3.8 million and $34.7 million, respectively, for the 2013 Successor Period.

Coal Sales

Coal sales for the year ended December 31, 2014 were $419.8 million compared to coal sales of $219.1 million and $158.8 million for the 2013 Predecessor Period and 2013 Successor Period, respectively. The increase in coal sales was due to a 1.4 million ton increase in sales volumes reflecting higher export shipments for the period, partially offset by a decrease in coal sales realized per ton as compared to the 2013 Predecessor Period, which was primarily driven by higher export shipments. The export sales mix increased to 21% of tons sold during 2014 versus only 9% during 2013.

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Other Revenues, Net

Other revenues, net was $0.4 million during 2014 compared to $0.8 million and $1.4 million for the 2013 Predecessor Period and the 2013 Successor Period, respectively. The decrease in other revenues is due primarily to a payment in the 2013 Successor Period (that did not recur in 2014) by one of our customers in respect of certain governmental impositions that increased our mining costs.

Cost of Coal Sales, Exclusive of Items Shown Separately

Cost of coal sales, exclusive of items shown separately, for the year ended December 31, 2014 was $232.8 million compared to $140.8 million and $96.2 million for the 2013 Predecessor Period and the 2013 Successor Period, respectively. The decrease is primarily due to decreases in our direct mining costs per ton, partially offset by the increase in tons sold. The decrease in direct mining costs per ton resulted from improved operating efficiencies achieved through higher production levels primarily at our Skyline mine and to a lesser extent at our Sufco mine in the year ended December 31, 2014 compared to the 2013 Predecessor Period and the 2013 Successor Period.

Transportation

Transportation expenses for the year ended December 31, 2014 were $44.4 million compared to $30.5 million and $19.7 million for the 2013 Predecessor Period and the 2013 Successor Period, respectively. This decrease is due to transportation benefits gained by the Quitchupah Road project (please read "—Liquidity and Capital Resources—Long-Term Debt—Quitchupah Road Debt") as well as increased sales from our Skyline mine, which has direct mine to rail capabilities, partially offset by increased export shipments.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization expenses for the year ended December 31, 2014 were $81.1 million compared to $22.0 million and $27.3 million for the 2013 Predecessor Period and the 2013 Successor Period, respectively. This increase reflects our stepped up basis in equipment and reserves as a result of the acquisition of CFC by our sponsor versus the lower carrying cost held by the Predecessor. Because a new asset basis can inhibit meaningful comparison of historical results before and after the change of control, depreciation, depletion and amortization for 2014 and the 2013 Successor Period are not comparable to depreciation, depletion and amortization for the 2013 Predecessor Period.

Amortization of Acquired Sales Contracts

Amortization of acquired sales contracts for the year ended December 31, 2014 were $12.1 million compared to $3.7 million for the 2013 Successor Period. This increase reflects a greater amortization period (since acquisition, essentially 4.5 months in 2013 versus 12 months of 2014) over which the intangible asset is amortized. There was no amortization of acquired sales contracts during the 2013 Predecessor Period.

Selling, General and Administrative

Selling, general and administrative expenses remained relatively consistent at $17.6 million for the year ended December 31, 2014 compared to $8.0 million and $9.6 million for the 2013 Predecessor Period and the 2013 Successor Period, respectively.

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Interest Expense, Net

Interest expense, net for the year ended December 31, 2014 was $36.2 million compared to $13.6 million (representing 135 days) for the 2013 Successor Period. Interest expense increased as a result of the acquisition debt secured to acquire CFC in August 2013. There was no interest expense for the 2013 Predecessor Period as the Predecessor allocated no corporate or parent company debt to CFC but did allocate interest income on the intercompany cash balance.

Net Income (Loss)

We realized a net loss of $4.9 million for the year ended December 31, 2014 compared to net income of $17.9 million for the 2013 Predecessor Period and net loss of $9.8 million for the 2013 Successor Period. This change was primarily due to the following: (i) increased depreciation, depletion and amortization expenses, (ii) increased interest expense, (iii) increased amortization of acquired sales contracts, and (iv) decreased other revenues, partially offset by (i) increased coal sales, (ii) decreased transportation expense, and (iii) decreased cost of coal sales.

Adjusted EBITDA

We realized Adjusted EBITDA of $125.3 million for the year ended December 31, 2014 compared to $40.7 million and $34.7 million for the 2013 Predecessor Period and the 2013 Successor Period, respectively. This change was primarily due to increased coal sales, decreased transportation expense, and decreased cost of coal sales, offset in part by decreased other revenues.

Liquidity and Capital Resources

We expect that our cash flow from operations, available capacity under our new revolving credit facility and issuances of equity and debt securities (including the New Notes) will be sufficient to meet our short-term working capital requirements and long-term capital expenditure requirements.

Following the completion of this offering, we intend to pay a minimum quarterly distribution of $ per common unit and subordinated unit per quarter, which equates to $ million per quarter, or $ million per year, based on the number of common and subordinated units to be outstanding immediately after completion of this offering, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner and its affiliates. We do not have a legal obligation to pay this distribution. Please read "Cash Distribution Policy and Restrictions on Distributions."

Our other primary uses of cash include, but are not limited to, the cash costs of coal production, capital expenditures, coal reserve lease and royalty payments, production taxes, debt service costs (interest and principal), lease obligations, transportation and throughput agreements and member distributions. We have made significant capital expenditures to develop our existing mines and related transportation infrastructure. Future longwall development and the associated capital expenditures will continue to be implemented sequentially and will be dependent on our operating cash flow and our access to the capital markets. We estimate that it could cost approximately $100.0 million (based on our experience developing our existing operations and the projected mine plans) to develop the Fossil Rock reserves. In the event that the capital markets are unavailable, we are not obligated or committed to use cash for expansion capital expenditures and would adjust the timing and pace of our growth accordingly.

We categorize our capital expenditures as either:

- maintenance capital expenditures, which are cash expenditures made to maintain our long-term operating capacity or net income; or

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- expansion capital expenditures, which are cash expenditures, including transaction expenses, made to increase our operating capacity or net income over the long term.

Historically, we did not make a distinction between maintenance capital expenditures and expansion capital expenditures. For the year ended December 31, 2014 and the three months ended March 31, 2015, we incurred capital expenditures of $28.5 million and $6.0 million, respectively. We expect to spend $ million and $ million on maintenance capital expenditures for the year ending December 31, 2015 and for the twelve months ending June 30, 2016, respectively, and $ million and $ million on expansion capital expenditures for the year ending December 31, 2015 and for the twelve months ending June 30, 2016, respectively. Please read "Cash Distribution Policy and Restrictions on Distributions."

Cash Flows

Comparison of Cash Flows for Three Months Ended March 31, 2015 to the Three Months Ended March 31, 2014

The following is a summary of net cash provided by or used in each of the indicated types of activities during the periods indicated:

	Successor			
	Three Months Ended March 31, 2014	Three Months Ended March 31, 2015	Increase/ (Decrease) $	Increase/ (Decrease) %
	(in thousands)			
Net cash provided by operating activities	$ 12,941	$ 5,454	$ (7,487)	(58)%
Net cash used in investing activities	(1,119)	(5,960)	(4,841)	(433)%
Net cash (used in) provided by financing activities	(11,822)	506	12,328	104%

Net cash provided by operating activities was $5.5 million for the three months ended March 31, 2015 compared to $12.9 million provided by operating activities for the three months ended March 31, 2014. The decrease in net cash provided by operating activities was largely due to decreased net (loss) income as adjusted for noncash items of $7.0 million in addition to a decrease in working capital of $0.5 million. The decrease in net (loss) income as adjusted for noncash items is due primarily to decreased coal sales and increased selling, general and administrative expenses, offset in part by decreased cost of coal sales and decreased interest expense.

Net cash used in investing activities was $6.0 million for the three months ended March 31, 2015 compared to $1.1 million for the three months ended March 31, 2014. The increase in cash used in investing activities related entirely to timing of investments in property, plant and equipment.

Net cash provided by financing activities was $0.5 million for the three months ended March 31, 2015 compared to $11.8 million used in financing activities for the three months ended March 31, 2014.

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Both periods include substantial member distributions and proceeds/payments on long-term debt and notes payable as illustrated in the table below:

	Successor			
	Three Months Ended March 31, 2014	Three Months Ended March 31, 2015	Increase/ (Decrease) $	Increase/ (Decrease) %
	(in thousands)			
Proceeds from long-term debt and notes payable	$ 5,025	$ 20,257	$ 15,232	303%
Payments on long-term debt and notes payable	(12,684)	(12,599)	85	1%
Net distributions to parent	(4,163)	(7,152)	(2,989)	(72)%
Net cash (used in) provided by financing activities	$ (11,822)	$ 506	$ 12,328	104%

Comparison of Cash Flows for Year Ended December 31, 2014 to the 2013 Predecessor Period and the 2013 Successor Period

The following is a summary of net cash provided by or used in each of the indicated types of activities during the periods indicated:

	Predecessor	Successor	
	Year Ended December 31, 2013		
	Period from January 1, 2013 to August 16, 2013	Period from August 16, 2013 to December 31, 2013	Year Ended December 31, 2014
		(in thousands)	
Net cash provided by operating activities	$ 45,964	$ 14,858	$ 84,524
Net cash used in investing activities	(5,217)	(8,373)	(27,044)
Net cash used in financing activities	(40,807)	(6,485)	(57,480)

Net cash provided by operating activities was $84.5 million for the year ended December 31, 2014 compared to $46.0 million and $14.9 million provided by operating activities for the 2013 Predecessor Period and the 2013 Successor Period, respectively. The increase in net cash provided by operating activities was largely due to increased net income as adjusted for noncash items of $30.6 million, partially offset by a decrease in working capital of $6.9 million. The increase in net income as adjusted for noncash items is due primarily to increased coal sales, decreased transportation costs and decreased cost of coal sales, offset in part by increased interest expense. The decrease in working capital is primarily driven by increased inventory, offset partially by decreased accounts receivable.

Net cash used in investing activities was $27.0 million for the year ended December 31, 2014 compared to $5.2 million and $8.4 million used in investing activities for the 2013 Predecessor Period and the 2013 Successor Period, respectively. The primary use of cash during the periods related to investments in property, plant and equipment of $28.5 million for the year ended December 31, 2014 compared to $5.7 million and $3.8 million for the 2013 Predecessor Period and the 2013 Successor Period, respectively. During the year ended December 31, 2014, our surety company returned $1.5 million of the $4.6 million of cash previously retained as collateral for our reclamation bonds during the 2013 Successor Period.

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Net cash used in financing activities was $57.5 million for the year ended December 31, 2014, compared to $40.8 million and $6.5 million used in financing activities for the 2013 Predecessor Period and the 2013 Successor Period, respectively. Both periods include substantial member distributions and non-related party note proceeds/payments as illustrated in the table below:

	Predecessor	Successor	
	Year Ended December 31, 2013		
	Period from January 1, 2013 to August 16, 2013	Period from August 16, 2013 to December 31, 2013	Year Ended December 31, 2014
		(in thousands)	
Proceeds from notes payable from non-related parties	$ —	$ 44,950	$ 27,449
Payments on notes payable from non-related parties	—	(23,079)	(84,494)
Payments for deferred financing costs	—	(383)	—
Member distributions, net	(40,807)	(27,973)	(435)
Net cash used in financing activities	$ (40,807)	$ (6,485)	$ (57,480)

Long-Term Debt

Senior Secured Credit Facilities

On August 16, 2013, our sponsor entered into loan documentation (collectively, the "Senior Secured Credit Facilities") to finance the purchase of CFC. The Senior Secured Credit Facilities provided for a $35.0 million senior secured asset-backed revolving credit facility, a $335.0 million senior secured first lien term loan and a $100.0 million senior secured second lien term loan.

Under the Senior Secured Credit Facilities, the maximum senior secured leverage ratio of our sponsor must not exceed 3.5x as of March 31, 2015 or December 31, 2014. Our sponsor was in compliance with this covenant as of March 31, 2015 and December 31, 2014.

Certain of our subsidiaries guarantee, and the equity interests and substantially all of the assets of certain of these subsidiaries secure, the Senior Secured Credit Facilities. Following the closing of this offering, we expect that neither we nor our subsidiaries will have ongoing liabilities and obligations under the Senior Secured Credit Facilities and that the liens on the assets of certain of our subsidiaries securing borrowings under these facilities will be released. Please read Note 8 to the historical financial statements for the years ended December 31, 2014 and 2013 included elsewhere in this prospectus for information on the Senior Secured Credit Facilities.

Quitchupah Road Debt

In 2012, CFC entered into an agreement with the State of Utah for the construction of a paved county road (the "Quitchupah Road") to shorten its transportation routes from the Sufco mine to PacifiCorp's Hunter Power Plant. The Quitchupah Road project was funded by CFC through the issuance of County Municipal Financing Bonds with Sevier County, Utah ("Sevier").

CFC agreed to repay Sevier for the cost of the road with repayments to begin once construction was complete. The original principal amounts owed to Sevier are comprised of a $29.9 million repayment agreement for construction of the Quitchupah Road and a $1.4 million promissory note for reimbursement of road improvement costs incurred prior to the start of the Quitchupah Road project. The promissory note matures on March 1, 2018 and incurs interest at 2.5% annually and is payable in arrears. Principal and interest payments for the promissory note commenced on March 1, 2014 and are payable in five equal annual installments of $293,000. The repayment agreement matures on March 1, 2027 and incurs interest at 2.4% annually. Principal and interest payments for the repayment agreement

commenced on March 1, 2014 and are payable in 14 annual installments of varying amounts as specified in the repayment agreement.

Prudential Notes

CFC had outstanding equipment notes totaling $10.8 million and $12.5 million with Prudential Insurance Company of America as of March 31, 2015 and December 31, 2014, respectively. These notes bear interest at LIBOR (subject to a floor of 1%) plus a margin of 5.1% and are due in various monthly installments through 2016. CFC may prepay the Prudential Notes, in whole but not in part, by paying a 2% prepayment fee, which steps down to 1% after October 11, 2015, and certain out-of-pocket expenses incurred by the lenders. The notes are secured by liens on the related equipment and are guaranteed by subsidiaries of our sponsor. CFC recorded $312,000 of capitalized deferred financing costs related to these notes during 2013, which are being amortized over the term of the notes. Unamortized deferred financing costs approximated $165,000 and $191,000 as of March 31, 2015 and December 31, 2014, respectively. We expect to repay the outstanding Prudential Notes in full with proceeds from this offering. Please read "Use of Proceeds."

PacifiCorp Notes

In June 2015, two of our wholly owned subsidiaries issued notes in connection with the Utah Transaction. Hunter Prep Plant, LLC issued a $10 million note in favor of PacifiCorp, which bears interest at 7% and matures on December 31, 2019. Fossil Rock Resources, LLC issued a $30 million note in favor of Fossil Rock Fuels LLC, an affiliate of PacifiCorp, which bears interest at 7% and matures on the earlier of August 31, 2015 or the refinancing of the Senior Secured Credit Facilities.

The notes are guaranteed by our sponsor and are subordinated to the Senior Secured Credit Facilities. We expect to repay the outstanding PacifiCorp Notes in full with net proceeds from this offering and the offering of the New Notes. Please read "Use of Proceeds."

Notes Payable to Imperial Premium Financing Specialists

In February 2015, our sponsor financed annual insurance premiums for its insurance policies in the amount of $13.3 million with Imperial Premium Financing Specialists ("IPFS"). The note bears interest at 3.9% with monthly payments of $1.2 million. Amounts owed by our sponsor to IPFS for financed insurance premiums totaled $9.5 million as of March 31, 2015, of which $7.2 million was allocated to CFC. No amounts were outstanding with IPFS as of December 31, 2014.

Revolving Credit Facility

In connection with the closing of this offering, we expect to enter into a -year, $ million revolving credit facility. The credit facility will be available to fund working capital, for the issuance of letters of credit, to finance capital expenditures and other permitted payments and for other lawful corporate purposes. Borrowings under the credit facility will bear interest at .

The credit facility will contain representations and warranties and affirmative and negative covenants customary for transactions of this nature.

Senior Secured Notes

In connection with the closing of the offering of New Notes, Finance Corp. deposited into an escrow account the gross proceeds from the New Notes offering, plus an amount sufficient to pay certain accrued interest and accreted yield. The release of the escrowed funds will be subject to the satisfaction of certain conditions, including the consummation of this offering (the "Escrow Release Conditions"). From and after the satisfaction of the Escrow Release Conditions, which we expect to

occur concurrently with the closing of this offering, the partnership will become a co-issuer of the New Notes and a party to the indenture governing the New Notes.

Interest payments will be due semi-annually on and . Subject to certain limitations, we will be able to redeem some or all of the New Notes by paying specified redemption prices in excess of the principal amount, plus accrued and unpaid interest, if any, prior to , 20 or by paying their principal amount thereafter, plus accrued and unpaid interest, if any.

The New Notes will be jointly and severally guaranteed by all of our existing and future restricted subsidiaries that guarantee our debt under our new revolving credit facility, and will be secured by substantially all of our assets.

The indenture governing the New Notes, among other things, will limit our ability and the ability of our restricted subsidiaries to incur additional indebtedness and issue preferred equity; pay dividends or distributions; repurchase equity or repay subordinated indebtedness; make investments or certain other restricted payments; create liens; sell assets; enter into agreements that restrict dividends, distributions, or other payments from restricted subsidiaries; enter into transactions with affiliates; and consolidate, merge, or transfer all or substantially all of their assets and the assets of their restricted subsidiaries on a combined basis.

Upon the occurrence of certain transactions constituting a "change in control" as defined in the indenture, holders of our New Notes could require us to repurchase all outstanding New Notes at % of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase.

Off-Balance Sheet Arrangements

In the normal course of business, we are party to certain off-balance sheet arrangements, including operating leases, coal reserve leases, take-or-pay transportation obligations, bank letters of credit and surety bonds. Liabilities related to these arrangements are generally not reflected in our consolidated balance sheet and except for coal reserve leases, take-or-pay transportation obligations and operating leases, we do not expect any material impact on our cash flows, results from operations or financial condition to result from these off-balance sheet arrangements.

We use surety bonds to secure reclamation and other miscellaneous obligations. As of March 31, 2015 and December 31, 2014, outstanding surety bonds with third parties for post-mining reclamation totaled approximately $24.4 million and $23.8 million, respectively. We had restricted cash totaling $3.1 million as of both March 31, 2015 and December 31, 2014, to secure bonding obligations.

Quantitative and Qualitative Disclosures about Market Risk

We define market risk as the risk of economic loss as a consequence of the adverse movement of market rates and prices. We believe our principal market risks include commodity price risk, interest rate risk and credit risk, which are disclosed below.

Commodity Price Risk

We have commodity price risk as a result of changes in the market value of our coal. We try to minimize this risk by entering into long-term fixed-price coal supply agreements that provide for price escalators, and we may from time to time enter into commodity hedge agreements. As of March 31, 2015 and December 31, 2014, we had 11.2 million tons committed and priced (subject to price escalators) for 2015 and 9.9 million tons expected and priced (subject to price escalators) for 2016. Currently, we have 9.0 million tons expected and priced for 2016. We did not have any hedges in place as of March 31, 2015 or December 31, 2014.

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Interest Rate Risk

We are exposed to market risk associated with interest rates due to our existing level of indebtedness. At the closing of this offering, we expect to have total borrowings outstanding of $ million. The impact of a 1% increase in the interest rate on this amount of debt would result in an increase in interest expense, and a corresponding decrease in our results of operations, of approximately $ million annually, assuming that our indebtedness remained constant throughout the year. We may use certain derivative instruments to hedge our exposure to variable interest rates in the future, but we currently do not have any hedges in place.

Credit Risk

We have credit risk associated with our customers and counterparties in our coal supply agreements. We have procedures in place to assist in determining the creditworthiness for such customers and counterparties. Generally our customers pay for individual train or vessel shipments. In other cases, several of our electric utility customers pay multiple times within a month to limit our exposure. At both March 31, 2015 and December 31, 2014, no allowance was recorded for uncollectible accounts receivable as all amounts were deemed collectible.

Contractual Obligations

The following is a summary of our significant contractual obligations as of March 31, 2015:

	Total	Less than 1 Year	1 - 3 Years	4 - 5 Years	More than 5 Years
			(in thousands)		
Long-term debt(1)	$ 387,035	$ 52,418	$ 45,809	$ 60,237	$ 228,571
Coal leases and royalties(2)	4,034	642	928	797	1,667
Other leases(3)	573	573	—	—	—
Total(4)	$ 391,642	$ 53,633	$ 46,737	$ 61,034	$ 230,238

(1) Includes $343.3 million attributable to our sponsor's Senior Secured Credit Facilities, $25.8 million attributable to the Quitchupah Road debt, $10.8 million attributable to the Prudential Notes, and $7.2 million attributable to the IPFS notes. Excludes interest payments due to uncertainty about their timing and/or amounts as well as $8.6 million of unamortized discounts. In connection with the closing of this offering, we expect that CFC will be released as a guarantor under our sponsor's Senior Secured Credit Facilities, and the liens on the assets contributed to us and securing borrowings under these facilities will be released. As a result, neither we nor the subsidiaries that will be contributed to us will have ongoing liabilities and obligations under the Senior Secured Credit Facilities. We expect to repay the outstanding Prudential Notes in full with proceeds from this offering. In connection with the closing of this offering, we expect to enter into a -year, $ million revolving credit facility under which we expect to have $ million of borrowings upon completion of this offering, and issue $ million aggregate principal amount of our % senior secured notes due .

(2) Represents future minimum cash payments due under our various coal reserve lease and royalty obligations.

(3) Represents future minimum cash payments due under our various operating leases.

(4) The contractual obligation table does not include asset retirement obligations. Asset retirement obligations result primarily from statutory, rather than contractual, obligations and the ultimate timing and amount of the obligations are an estimate. As of March 31, 2015 and December 31, 2014, we had $9.4 million and $9.2 million, respectively, recorded to our balance sheet for asset retirement obligations.

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Coal and Surface Leases and Overriding Royalties

A substantial amount our coal is produced from mineral reserves leased from various landowners. Our main lessor is the U.S. government, from which we lease coal under terms set by Congress and administered by the BLM through the process described under "Business—Coal Reserves and Non-Reserve Coal Deposits—Reserve Acquisition Process." These leases are generally for an initial term of ten years but may be extended by diligent development and mining of the reserves until all economically recoverable reserves are depleted. We have met the diligent development requirements for substantially all of these federal leases either directly through production, by including the lease as a part of a logical mining unit with other leases upon which development has occurred, or by paying an advance royalty in lieu of continued operations. Annual production on these federal leases must total at least 1% of the original amount of coal in the entire logical mining unit. In addition, royalties are generally payable monthly at a rate of 8% of the gross realization for coal produced using underground mining methods. Many BLM leases also require payment of a lease rental or minimum royalty, payable either at the time of execution of the lease or in periodic installments. The remainder of our leased coal is generally leased from state governments, land holding companies and various individuals. The duration of these leases varies. Typically, the lease terms are automatically extended as long as active mining continues. Royalty payments are generally based upon a specified rate per ton or a percentage of the gross realization from the sale of the coal.

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BUSINESS

Overview

We were recently formed by our sponsor as a growth-oriented master limited partnership focused on:

- operating safe, low-cost, strategically-located underground coal mines that produce high quality (high Btu, low sulfur) thermal coal;
- providing the lowest delivered cost fuel option (coal or natural gas) to our key regional customers, capitalizing on our high productivity, high quality coal and geographic proximity to these customers;
- fulfilling and extending our long-term, high-volume, fixed-price coal supply agreements;
- growing our cash flows through prudent acquisitions of strategically-positioned assets; and
- capitalizing on our differentiated transportation and logistics network that positions us as the only U.S. coal producer with contracted U.S. West Coast export capacity.

Our Operations

We operate three underground coal mines in Utah with a productive capacity of approximately 12.6 million tons per year: (i) the Sufco mine, near Salina, Utah, which is a longwall operation, (ii) the Skyline mine, near Scofield, Utah, which is a longwall operation, and (iii) the Dugout Canyon mine, near Price, Utah, which has been a longwall operation but is currently a multi-continuous miner operation. Our mines are located in the Uinta Basin in Utah within the Western Bituminous region where a significant percentage of the coal qualifies as "compliance coal" under the Clean Air Act. According to Wood Mackenzie, we are one of the largest producers of low-cost, high margin thermal coal in the Western Bituminous region. Our operations are some of the safest underground coal mines in the United States. Since 2011, we have reduced our total reportable injury rate by approximately 67%, to 0.5, and have been recognized for our outstanding performance in environment, health and safety management through our receipt of numerous environmental and safety awards.

Our high Btu, low sulfur coal reserves, highly skilled and experienced, non-union workforce and industry leading safety track record have made us one of the most productive underground bituminous coal producers in the United States. As shown in the chart below, our operations were among the most productive underground coal mines in the United States for the year ended December 31, 2014 on a clean tons produced per man hour basis based on MSHA data.

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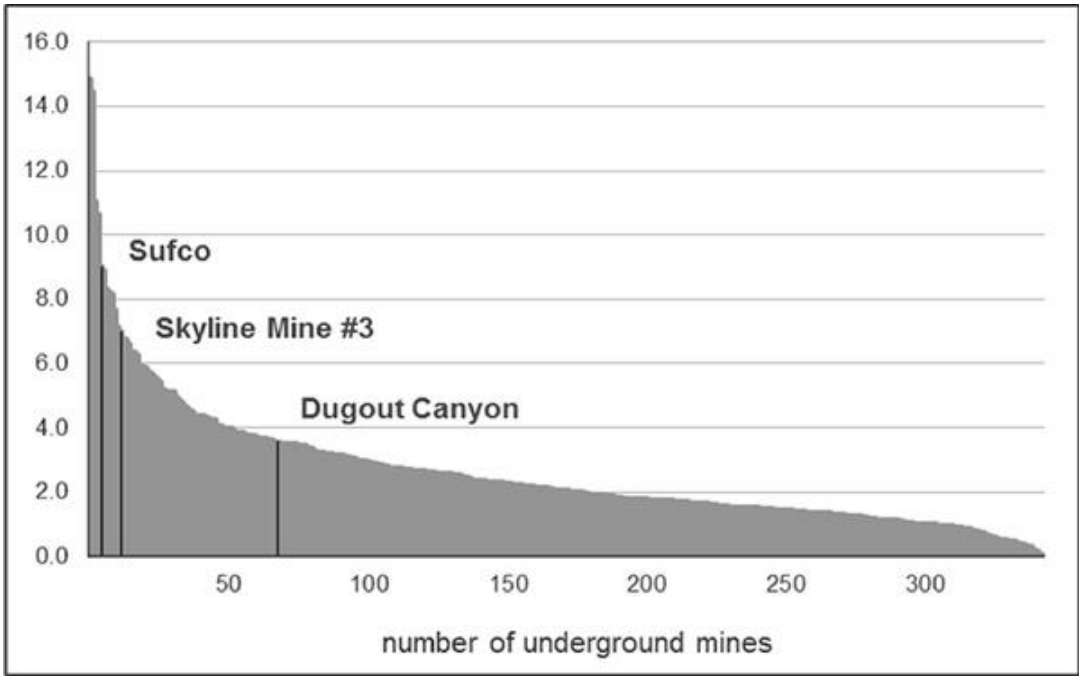
U.S. Underground Coal Mine Productivity (2014)

Clean coal production tons per employee man hour. Darker shading denotes mines operated by us.



Source: Productivity of underground coal mines in the United States with over 100,000 tons produced during 2014 on a clean ton produced per man hour basis based on 2014 MSHA data.

The high productivity of our strategically-located mines, together with our sponsor's transportation and logistics network, enables us to deliver our coal to our key regional customers at a lower cost per Btu compared to coal from other producers in the Western Bituminous region, coal from other basins and natural gas, even when adjusted for different heat rate efficiencies between coal and natural gas-fired power plants. The high productivity of our mines and our focus on cost control has enabled us to achieve low direct mining costs per ton. During the year ended December 31, 2014 and the three months ended March 31, 2015, our operations had direct mining costs per ton of $20.31 and $22.90, respectively. Direct mining costs per ton is defined as cost of coal sales, exclusive of items shown separately (as defined in Appendix B), divided by tons sold.

Our Long-Term Contract Portfolio

The majority of our coal sales for the year ended December 31, 2014 and the three months ended March 31, 2015 were made to domestic customers pursuant to long-term, high-volume coal supply agreements with fixed pricing, subject to certain price escalators and adjustments. On a pro forma basis, after giving effect to the closing of the Utah Transaction (described below), we expect coal sales under our existing coal supply agreements of approximately 11.2 million tons in 2015, 9.0 million tons in 2016, 9.5 million tons in 2017 and 9.3 million tons in 2018, which represent approximately 100%, 82%, 86% and 84%, respectively, of our production for the twelve months ended March 31, 2015, which should provide significant sustainable revenue and allow us to generate stable and reliable cash flows. These estimates are based on our historical relationship with our customers and management's knowledge of the customers' coal requirements and the customers' other coal supply arrangements.

As part of our domestic sales portfolio, we have multi-year coal supply agreements with PacifiCorp and IPA, two investment-grade regional utilities that operate power plants located in close proximity to

our mines. These plants were designed to burn high Btu, low sulfur Utah coal. Our coal supply agreements with PacifiCorp and IPA provide for aggregate sales of (i) a minimum of 7.0 million tons and a maximum of 10.5 million tons per year through December 31, 2020, (ii) a minimum of 4.5 million tons and a maximum of 6.0 million tons per year through December 31, 2024 and (iii) a minimum of 2.0 million tons and a maximum of 3.0 million tons per year through December 31, 2029. We believe that our contracts with PacifiCorp and IPA that are set to expire in 2020 and 2024 have the potential to be extended in the future, should we choose to do so. All of our coal supply agreements with PacifiCorp and IPA include price escalators, as well as provisions that allow us to pass through (by means of a price increase) certain increases in mining and transportation costs. Please read "—Customers."

Our Proven Performance and Growth

We have significantly enhanced the performance of our mines since they were acquired by our sponsor in August 2013. Coal production at our mines increased from 9.7 million tons for the year ended December 31, 2013 to 11.4 million tons for the year ended December 31, 2014. During the year ended December 31, 2014, we realized net loss, operating income and Adjusted EBITDA of $4.9 million, $31.4 million and $125.3 million, respectively, as compared to net income, operating income and Adjusted EBITDA of $8.1 million, $22.1 million and $75.5 million, respectively, for the year ended December 31, 2013. Please read "Prospectus Summary—Summary Historical and Pro Forma Financial and Other Data—Non-GAAP Financial Measures" for the definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our most directly comparable financial measure calculated and presented in accordance with GAAP.

We plan to seek acquisition targets similar to our current operations, utilizing our sales contract position, our strategic export capacity and our proven ability to maximize productivity in order to facilitate future accretive transactions. Pursuant to the omnibus agreement that we expect to enter into in connection with this offering, our sponsor will grant us a right of first refusal with respect to certain coal and terminal properties. In addition, we expect to enter into an agreement with Bowie Refined Coal, LLC, an affiliate of our sponsor, providing us with a right of first refusal to acquire certain refined coal projects that it owns. Please read "Certain Relationships and Related Party Transactions." Additionally, we will pursue three organic development projects in the next decade; specifically, the addition of a third continuous miner to our Dugout Canyon mine, the development of the Fossil Rock reserves and the development of reserves in the Lower Hiawatha seam of our Sufco mine. Finally, we expect to benefit from increasing demand and prices for our coal in the export markets of the Pacific Rim.

Our Export Capabilities

We benefit from a differentiated transportation and logistics network established by our sponsor, including its access to port terminals in California through which we export our coal to a variety of growing economies on the Pacific Rim. According to Wood Mackenzie, overall demand for thermal coal imports into the Pacific market is expected to increase from 757 million metric tons in 2014 to 910 million metric tons in 2020 and 1.3 billion metric tons in 2030.

These international markets provide us with alternatives to our core domestic market, diversification of our customer base and an important economic outlet for our coal. Since the acquisition of our mines by our sponsor in August 2013, our coal has been successfully exported to customers in Mexico, Japan, China, Guatemala, Chile and Hawaii. Through our sponsor, we are the only coal producer with contracted U.S. West Coast export capacity, with access to an aggregate throughput capacity of approximately 5.7 million tons per year (approximately 4.0 million tons per year at the Port of Stockton, California and approximately 1.7 million tons per year at the Levin-Richmond

Terminal). Prior to our sponsor leasing these terminals, no significant amount of thermal coal had been shipped through these terminals for over 10 years.

For the year ended December 31, 2014, our sponsor exported approximately 3.3 million tons through the Port of Stockton, California and the Levin-Richmond Terminal, and we expect our sponsor to export approximately 1.0 million tons through these terminals for the year ending December 31, 2015. In addition, we export through the Port of Long Beach, California. For the year ended December 31, 2014, we exported approximately 500,000 tons of our coal through the Port of Long Beach, California. We do not expect that a material portion of our coal will be exported through this port for the year ending December 31, 2015.

Trafigura AG is the exclusive marketer of our uncommitted coal, and its parent company, Trafigura BV, indirectly owns a minority interest in our sponsor through Galena. Trafigura AG and its affiliates directly or indirectly market approximately 50 million tons of coal per year in the international market. By leveraging Trafigura AG's and its affiliates' significant expertise in the coal export market and existing commodities trading infrastructure, we are able to sell our coal internationally to a variety of intermediary and end users in the power generation business.

Recent Developments

Utah Transaction. On June 5, 2015, we acquired (through our wholly-owned subsidiary, Fossil Rock Resources, LLC) certain undeveloped, high Btu, low sulfur coal reserves in Utah (the "Fossil Rock reserves") from an affiliate of PacifiCorp (the "Utah Transaction"). As part of the Utah Transaction, our sponsor entered into an agreement with PacifiCorp to supply all of the coal requirements of PacifiCorp's Huntington Power Plant in Utah through 2029. The volume for the new coal supply agreement with PacifiCorp will be supplied predominantly with our coal. The Fossil Rock reserves increase our proven and probable reserves by an estimated 11.2 million tons and 32.5 million tons, respectively. We plan to begin development of the Fossil Rock reserves in 2017, begin production from the Fossil Rock reserves with continuous miner units in 2018 and spend approximately $100.0 million ratably between 2017 and 2021 to move the Sufco mine longwall system to Fossil Rock for operation in 2021. At full production, we expect to produce approximately 4.0 million tons of coal per year from the Fossil Rock reserves from 2017 through 2034. The Fossil Rock reserves are located closer to PacifiCorp's Huntington and Hunter Power Plants than our existing mines, which we believe will significantly reduce our transportation costs to this principal customer. As part of the Utah Transaction, we also acquired (through our subsidiary, Hunter Prep Plant, LLC) certain real property near PacifiCorp's Hunter Power Plant, which we believe will enhance our coal blending capabilities for deliveries to the Hunter Power Plant.

Flat Canyon Lease. On June 17, 2015, we were notified by the BLM, as part of the lease by application process, that we submitted the only bid in the competitive lease sale of the Flat Canyon tract held on June 17, 2015. On June 19, 2015, we were notified by the BLM, as part of the lease by application process, that our bid met or exceeded the BLM's estimate of the fair market value of the tract, which contains approximately 14.2 million tons and 15.2 million tons of proven and probable reserves, respectively. The issuance by the BLM of the lease of the Flat Canyon tract remains subject to a 30-day antitrust review of the U.S. Department of Justice. The leasing action could also be challenged in the Department of Interior's Board of Land Appeals or in federal district court. The May 15, 2015 Notice of Lease Sale of the Flat Canyon tract prompted letters by several non-governmental organizations objecting to the lease sale on, among other things, environmental grounds. Please read "—Coal Reserves and Non-Reserve Coal Deposits—Reserve Acquisition Process."

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Business Strategies

Our principal business objective is to consistently generate stable cash flows that enable us to pay quarterly cash distributions to our unitholders and, over time, sustainably increase our quarterly distributions. We expect to achieve this objective through the following business strategies:

- **Maintaining industry-leading safety standards.** Safety is a top priority for us, and we incorporate and emphasize safety in all aspects of our operations, including mine operations and processes and equipment selection. Our mines have been industry leaders in the United States, with each having completed at least one calendar year without an MSHA recordable injury and each having received the National Mining Association's prestigious Sentinel of Safety award. We plan to continue working with equipment manufacturers in an effort to ensure our mining equipment and processes remain safe, and to continue implementing safety measures to maintain the high quality of our underground infrastructure.

- **Growing production and operating cash flows.** We expect our coal production and cash flows to increase as a result of the Utah Transaction, and we have a pipeline of potential organic development projects to further develop our reserve base with minimal additional surface infrastructure required. Additionally, we expect to pursue acquisitions from our sponsor through its portfolio of assets and contractual rights, as well as third-party opportunities for which we are uniquely positioned. Pursuant to the omnibus agreement that we expect to enter into in connection with this offering, our sponsor will grant us a right of first refusal with respect to certain coal and terminal properties. In addition, we expect to enter into an agreement with Bowie Refined Coal, LLC, an affiliate of our sponsor, providing us with a right of first refusal to acquire certain refined coal projects that it owns. Please read "Certain Relationships and Related Party Transactions."

- **Further strengthening our established relationships with our customers.** We are continuously evaluating opportunities to further strengthen our commercial relationships with our long-term customers. For example, in connection with the Utah Transaction, our sponsor entered into a new 15-year coal supply agreement with PacifiCorp, one of our principal customers, providing for additional sales to PacifiCorp of a minimum 2.0 million tons and a maximum of 3.0 million tons of coal per year through 2029. Please read "—Customers."

- **Maintaining our delivered cost advantage with our key regional customers.** Our mines have a track record of stable production and low direct mining costs per ton. During the year ended December 31, 2014 and the three months ended March 31, 2015, our operations had direct mining costs per ton of $20.31 and $22.90, respectively. Direct mining costs per ton is defined as cost of coal sales, exclusive of items shown separately (as defined in Appendix B), divided by tons sold. We intend to continue building upon and expanding our position as one of the lowest cost Western Bituminous coal producers. Low operating costs, driven by high-quality longwall reserves, a skilled and experienced non-union workforce and a consistent safety track record, combined with our geographical advantage and cost competitive transportation contracts, should allow us to maintain our overall competitive advantage on a delivered cost basis and continue to drive favorable margins in nearly any coal price environment, further differentiating us from our peers. We believe low direct mining costs per ton and consistent delivery of volumes and coal quality are critical to maintain both stable financial performance and solid relationships with our key regional customers.

- **Utilizing our sponsor's export capacity to expand the size and diversity of our coal sales portfolio.** While we view sales to local utility customers as our principal generator of cash flows, we expect to benefit from our sponsor's plan to further expand sales into international coal markets, which we expect to provide additional cash flows and diversification from our primary domestic market. We expect export coal markets to have the potential to provide significant

growth opportunities relative to the domestic coal market. Although the largest domestic coal producers have attempted to secure export capacity to access the Pacific market, we are the only coal producer with contracted U.S. West Coast export capacity. This provides us with unique competitive advantages, including the option of selling any uncommitted coal we produce into international markets.

- **Continuing to develop and grow our reserve base.** We believe our Dugout Canyon mine can support an additional continuous miner unit without any additional surface infrastructure, which would increase its productive capacity from approximately 1.1 million tons per year to approximately 1.5 million tons per year. The Fossil Rock reserves increase our proven and probable reserves by an estimated 11.2 million tons and 32.5 million tons, respectively, and at full production, we expect to produce approximately 4.0 million tons of coal per year from the Fossil Rock reserves from 2017 through 2034. The Fossil Rock reserves are located closer to PacifiCorp's Huntington and Hunter Power Plants than our existing mines, which we believe will significantly reduce our transportation costs to this principal customer. Additionally, we expect to obtain a lease from the BLM through the lease by application process for the Greens Hollow tract, which contains approximately 50.5 million tons of non-reserve coal deposits, including those in the Lower Hiawatha seam, accessible through our Sufco mine.

Competitive Strengths

We believe we are well-positioned to execute our business strategies because of the following competitive strengths:

- **Portfolio of multi-year, fixed-price coal supply agreements providing stable long-term cash flows.** We believe our long-term coal supply agreements provide significant sustainable revenue and should generate stable and reliable cash flows. On a pro forma basis, after giving effect to the closing of the Utah Transaction, we expect coal sales under our existing coal supply agreements of approximately 11.2 million tons in 2015, 9.0 million tons in 2016, 9.5 million tons in 2017 and 9.3 million tons in 2018, which represent approximately 100%, 82%, 86% and 84%, respectively, of our production for the twelve months ended March 31, 2015. Included in our sales portfolio are our coal supply agreements with PacifiCorp and IPA providing for aggregate sales of (i) a minimum of 7.0 million tons and a maximum of 10.5 million tons per year through December 31, 2020, (ii) a minimum of 4.5 million tons and a maximum of 6.0 million tons per year through December 31, 2024 and (iii) a minimum of 2.0 million tons and a maximum of 3.0 million tons per year through December 31, 2029, all of which have fixed pricing, subject to certain price escalators and adjustments as described in further detail under "—Customers."

- **Lowest delivered cost to key regional customers maintained by geographic advantage and productivity.** Our mines are strategically located in close proximity to our principal customers, and we have in place cost competitive options for both trucking and rail transportation of our coal to these customers. According to Wood Mackenzie, we can deliver our coal to PacifiCorp and IPA at a lower cost per Btu compared to coal from other producers in the Western Bituminous region, coal from other basins and natural gas, even when adjusted for different heat rate efficiencies between coal and natural gas-fired power plants. The boilers of these base load electricity generators in the Uinta Basin were engineered to burn Uinta Basin coal rather than the low energy content coal from the Powder River Basin or the high sulfur coal from the Illinois Basin. Our two longwall mines were among the 15 most productive underground coal mines in the United States for the year ended December 31, 2014, on a clean tons produced per man hour basis based on MSHA data. Our industry-leading productivity and resulting low direct mining costs per ton are driven by favorable geology and a highly motivated and skilled non-union workforce.

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- **Strategically positioned to take advantage of synergistic and value-added acquisition opportunities in the Western Bituminous region.** We are the largest producer of coal in the Uinta Basin, producing 84% more coal than the next largest Western Bituminous coal producer in the Uinta Basin in 2014, according to MSHA production data. In executing our acquisition strategy, we plan to seek acquisition targets similar to our current operations, utilizing our sales contract position, our strategic export capacity and our proven ability to maximize productivity in order to facilitate future accretive transactions. Retaining the largest footprint in the Uinta Basin provides us with a strong foundation for growth within both the Uinta Basin and the broader Western Bituminous region. Our contracted position and ability to sell coal into the international market should allow us to evaluate acquisition opportunities with potential for value creation by expanding production at operations that would otherwise be market constrained. Pursuant to the omnibus agreement that we expect to enter into in connection with this offering, our sponsor will grant us a right of first refusal with respect to certain coal and terminal properties. In addition, we expect to enter into an agreement with Bowie Refined Coal, LLC, an affiliate of our sponsor, providing us with a right of first refusal to acquire certain refined coal projects that it owns. Please read "Certain Relationships and Related Party Transactions."

- **Differentiated transportation and logistics network providing profitable access to growing markets for our coal on the Pacific Rim.** We are the only coal producer with contracted U.S. West Coast export capacity. According to Wood Mackenzie, overall demand for thermal coal imports into the Pacific market is expected to increase from 757 million metric tons in 2014 to 910 million metric tons in 2020 and 1.3 billion metric tons in 2030. We have access to export terminals in California with an aggregate throughput capacity of approximately 5.7 million tons per year. Our cost structure and the location of our mines allow us to profitably export coal when the applicable seaborne thermal benchmark price prevents our competitors from doing so. Our export capacity is enhanced by market reach through our sponsor's relationship with Trafigura AG, one of the largest global commodity trading houses. Trafigura AG is the exclusive marketer of our uncommitted coal and its parent company, Trafigura BV, indirectly owns a minority interest in our sponsor through Galena. Trafigura AG and its affiliates directly or indirectly market approximately 50 million tons of coal per year in the international market.

- **Proven management capabilities and industry leading safety standards.** Our mine management team is comprised of long-tenured coal mining professionals, highly skilled in the planning and execution of Western Bituminous coal mining operations. Our senior operations personnel have, on average, more than 30 years of experience in the coal industry. They are hands-on operators with substantial experience in operating safe mines, increasing productivity and reducing costs. In addition, our senior executives have a proven track-record of successfully identifying, acquiring, financing and integrating assets that enhance the value of our business. Our operations have exemplary safety records, and we strongly believe that safety is the most important factor in productivity. Safety is a focus and value in all aspects of our business. According to MSHA data, we have consistently outperformed national average rates in historical safety violations as well as lost-time safety incident rates.

Our Sponsor

One of our principal strengths is our relationship with our sponsor. Our sponsor is owned by Cedars and Galena. Cedars is a coal sector investor with a track record of acquiring, integrating and developing coal and coal-related assets. Galena is wholly owned by Galena Private Equity Resource Fund, which is managed by Galena Asset Management, a wholly-owned subsidiary of Trafigura BV. Trafigura AG, a wholly-owned subsidiary of Trafigura BV, is our exclusive marketing agent. Trafigura BV has 45 offices in 36 countries around the world and generated revenues of approximately $127.6 billion in 2014. By leveraging Trafigura AG's and its affiliates' significant expertise in the coal export market and existing commodities trading infrastructure, we are able to sell our coal internationally to a variety of intermediary and end users in the power generation business.

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Our sponsor has extensive experience in identifying, acquiring, financing and integrating assets that enhance the value of our business. Over the last four years, our sponsor has permitted, developed and/or operated four separate coal mining operations in the Western Bituminous region. In addition to acquiring CFC in 2013, our sponsor owns the Bowie #2 mine, located in Paonia, Colorado, which produced 2.4 million tons and 3.3 million tons of coal in 2014 and 2013, respectively. Our sponsor will retain the Bowie #2 mine and any related assets after the IPO Reorganization. Our sponsor successfully executed a business plan that increased the post-acquisition profitability of our operations, resulting in a 66% increase in Adjusted EBITDA from the year ended December 31, 2013 to the year ended December 31, 2014. We believe that our sponsor's experience and expertise in mergers and acquisitions of strategic assets will enhance our ability to achieve our growth objectives.

Upon consummation of this offering, we will be managed and operated by the board of directors and executive officers of our general partner, Bowie GP, LLC, a wholly-owned subsidiary of our sponsor. Some of our directors and all of our executive officers also serve as directors and executive officers of our sponsor. Following this offering, % of our outstanding common units and all of our outstanding subordinated units and incentive distribution rights will be owned, directly or indirectly, by our sponsor.

In connection with the closing of this offering, we expect to enter into the following agreements with our sponsor and its affiliates:

- Coal Supply Agreement—We expect to enter into a coal supply agreement with our sponsor pursuant to which it will purchase substantially all of our coal on substantially the same terms as our sponsor's agreements with our end customers.

- Coal Services Agreement—We expect to terminate the existing Coal Services Agreement among CFC, our sponsor and Trafigura AG and to enter into a new Coal Services Agreement among our operating company and its subsidiaries, our sponsor and Trafigura AG.

- Omnibus Agreement—We expect to enter into an omnibus agreement with our sponsor, pursuant to which it will grant us a right of first refusal with respect to certain coal and terminal properties and pursuant to which we will reimburse our sponsor on a cost-of-services basis for certain services performed on our behalf.

- Bowie Refined Coal Agreement—We expect to enter into an agreement with Bowie Refined Coal, LLC, an affiliate of our sponsor, providing us with a right of first refusal to acquire certain refined coal projects that it owns.

- Registration Rights Agreement—We expect to enter into a registration rights agreement with our sponsor pursuant to which we may be required to register the sale of the (i) common units issued (or issuable) to our sponsor pursuant to the contribution agreement, (ii) subordinated units and (iii) common units issuable upon conversion of the subordinated units pursuant to the terms of the partnership agreement.

For more information, please read "Certain Relationships and Related Party Transactions—Agreements with Affiliates in Connection with the Transactions."

Assets and Operations

Overview

We operate three underground coal mines in Utah with a productive capacity of approximately 12.6 million tons per year: (i) the Sufco mine, near Salina, Utah, which has one longwall system and three continuous miner units with a productive capacity of approximately 7.0 million tons per year, (ii) the Skyline mine, near Scofield, Utah, which has one longwall system and two continuous miner units with a productive capacity of approximately 4.5 million tons per year, and (iii) the Dugout

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Canyon mine, near Price, Utah, which has been a longwall operation but is currently a multi-continuous miner operation with a productive capacity of approximately 1.1 million tons per year. We operate as one reportable segment, as our Chief Executive Officer, serving as our Chief Operating Decision Maker (CODM), reviews financial information on the basis of our consolidated financial results for purposes of making decisions. Generally, the CODM evaluates performance and allocates resources based on Adjusted EBITDA. Discrete financial information sufficient to allow the CODM to make decisions is only available on a consolidated basis.

The Sufco mine has longwall and continuous miner reserves in the Upper Hiawatha and Lower Hiawatha seams, which have an average seam thickness of 10 feet. The Skyline mine has longwall and continuous miner reserves in the Lower O'Connor A, Lower O'Connor B and Flat Canyon seams, which have an average seam thickness of 10 feet. Please read "Prospectus Summary—Recent Developments—Flat Canyon Lease" for a description of the status of the Flat Canyon tract. The Dugout Canyon mine has longwall and continuous miner reserves in the Gilson and Rock Canyon seams in the Book Cliffs coalfield, which have an average seam thickness of 7 feet. The Dugout Canyon mine also has potential access to coal deposits in the adjacent Gilson seam northwest of current operations for which we are evaluating for future expansion. We produced 11.4 million tons and 9.7 million tons of high Btu coal for the years ended December 31, 2014 and 2013, respectively.

On June 5, 2015, we acquired the Fossil Rock reserves from an affiliate of PacifiCorp, which increase our proven and probable reserves by an estimated 11.2 million tons and 32.5 million tons, respectively, and provide a natural replacement for the low sulfur coal currently produced by our Sufco mine from the Upper Hiawatha seam, which we expect to be exhausted in the third quarter of 2021. We plan to begin development of the Fossil Rock reserves in 2017, begin production from the Fossil Rock reserves with continuous miner units in 2018 and spend approximately $100.0 million ratably between 2017 and 2021 to move the Sufco mine longwall system to Fossil Rock for operation in 2021. At full production, we expect to produce approximately 4.0 million tons of coal per year from the Fossil Rock reserves from 2017 through 2034. In addition, we expect to obtain a lease from the BLM through the lease by application process, described in further detail under "—Coal Reserves and Non-Reserve Coal Deposits—Reserve Acquisition Process," for the Greens Hollow tract, which contains approximately 50.5 million tons of non-reserve coal deposits accessible through our Sufco mine. Assuming our acquisition of the Greens Hollow tract, and subject to suitable demand in either domestic or international markets, we will have the ability to add a new longwall system to the Sufco mine to enable it to produce up to 7.0 million tons per year from the Lower Hiawatha seam. This production from the Sufco mine's Lower Hiawatha seam would replace the production from the Sufco mine's Upper Hiawatha seam and would be in addition to the 4.0 million tons of coal produced per year from the Fossil Rock reserves.

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On a pro forma basis, after giving effect to the closing of the Utah Transaction and the BLM's issuance of the Flat Canyon lease to us, the following table summarizes our assets and operations as of December 31, 2014:

	Sufco	Skyline	Dugout Canyon(1)	Fossil Rock(2)	Total
Location	Sevier County, UT	Carbon County, UT	Carbon County, UT	Emery County, UT	
Type of mining	Longwall, Continuous miner	Longwall, Continuous miner	Continuous miner	Longwall Continuous miner	
Reserves: (million tons)(3)					
Proven reserves	33.0	33.4(4)	10.7	11.2	88.3(4)
Probable reserves	28.2	21.4(4)	1.6	32.5	83.7(4)
Total proven and probable	61.2	54.8(4)	12.3	43.7	172.0(4)
Annual capacity (million tons)	7.0	4.5	1.1	—	12.6
Production: (million tons)(5)					
2014	6.5	4.2	0.7	—	11.4
2013	6.0	3.1	0.6	—	9.7
Coal sales realized per ton(6)					
2014	$ 39.14	$ 32.74	$ 35.66	$ —	$ 36.62
2013	$ 37.63	$ 36.87	$ 39.73	$ —	$ 37.59
Btu per pound(7)	10,916	11,540	11,844	11,550	—
Sulfur (%)	0.43	0.44	0.80	0.57	—
Loadouts	Levan & Salina	Skyline	Savage Energy Terminal	Fossil Rock	—
Transportation	Rail, Truck	Rail, Truck	Rail, Truck	Truck	—
Preparation plant	Castle Valley	Castle Valley	Castle Valley	—	—

(1) Subject to suitable demand in either domestic or international markets, we have the ability to add a third continuous miner unit to the Dugout Canyon mine without any additional surface infrastructure, and increase its productive capacity from approximately 1.1 million tons per year to approximately 1.5 million tons per year.

(2) We acquired the Fossil Rock reserves from an affiliate of PacifiCorp on June 5, 2015. At full production, we expect to produce approximately 4.0 million tons of coal per year from the Fossil Rock reserves from 2017 through 2034. Please read "—Overview—Recent Developments—Utah Transaction."

(3) Includes both assigned and unassigned reserves.

(4) On June 17, 2015, we were notified by the BLM, as part of the lease by application process, that we submitted the only bid in the competitive lease sale of the Flat Canyon tract held on June 17, 2015. On June 19, 2015, we were notified by the BLM, as part of the lease by application process, that our bid met or exceeded the BLM's estimate of the fair market value of the tract, which contains approximately 14.2 million tons and 15.2 million tons of proven and probable reserves, respectively. The issuance by the BLM of the lease of the Flat Canyon tract remains subject to a 30-day antitrust review of the U.S. Department of Justice. The leasing action could also be challenged in the Department of Interior's Board of Land Appeals or in federal district court. The May 15, 2015 Notice of Lease Sale of the Flat Canyon tract prompted letters by several non-governmental organizations objecting to the lease sale on, among other things, environmental grounds. Please read "—Coal Reserves and Non-Reserve Coal Deposits—Reserve Acquisition Process."

(5) Production is based upon our system of record.

(6) Coal sales realized per ton is defined as coal sales divided by tons sold.

(7) All Btus per pound are expressed on an as-received basis, including total moisture.

With over 88 million tons and 84 million tons of proven and probable coal reserves, respectively, including the Fossil Rock reserves and the Flat Canyon tract, we believe we are among the largest holders of coal reserves in the Western Bituminous region. Our reserves have thick coal seams and are characterized by roof and floor geology favorable for longwall mining.

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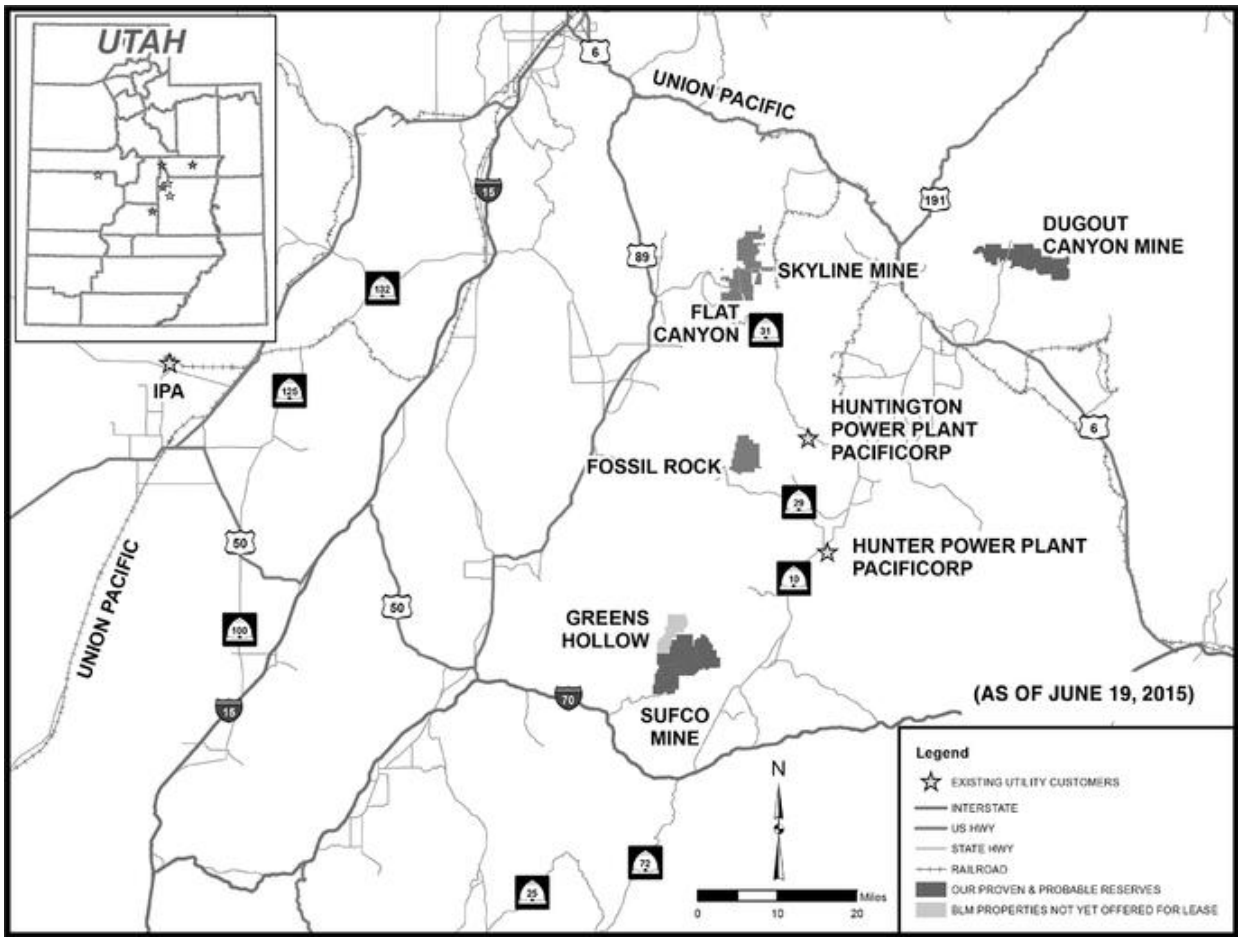
The following map shows the locations of our coal mines:



The Sufco mine is located on 27,550 acres in Sevier County, Utah approximately 30 miles northeast of Salina, Utah and 125 miles south of Salt Lake City, Utah. The Skyline mine is located on 12,290 acres in Carbon County, Utah approximately five miles southwest of Scofield, Utah and approximately 30 miles northwest of Price, Utah. The Dugout Canyon mine is located on 9,691 acres in Carbon County, Utah approximately 12 miles northeast of Price, Utah. The Sufco and Skyline mines are in the Wasatch Plateau coalfield and the Dugout Canyon mine is in the Book Cliffs coalfield, all of which are part of the Uinta Basin.

The Wasatch Plateau coalfield extends southwest about 90 miles from western Carbon County, Utah through western Emery County and into eastern Sanpete and Sevier Counties. The Wasatch coalfield is 13 to 22 miles wide. The eastern edge is bounded by the outcrop of the coal-bearing Blackhawk Formation and the western edge is bounded by a series of faults near the western edge of the Wasatch Plateau. Carbon and Emery Counties contain the northern and central Wasatch Plateau coalfield areas. Most of the coal in the Wasatch Plateau is in the lower third of the Blackhawk Formation. Eight coal beds have been identified that contain coal seams more than seven feet thick.

The northern part of the Wasatch Plateau coalfield is directly served by rail transportation. One spur leaves the main line of the Union Pacific railroad at the town of Colton and extends 15 miles southwest to serve the mines near Scofield, Utah, including the Skyline mine. Three other spurs branch

off at the town of Helper, with two running five miles west, one to the Savage Energy Terminal and the other one to our Levan rail loadout.

The Book Cliffs coalfield extends 70 miles across northern Carbon and eastern Emery Counties, with an average width of four miles. The field parallels the path of a Union Pacific railroad line, which offers operators in this field a transportation cost advantage, facilitating shorter truck hauls to the rail line. The coal beds in the Book Cliffs coalfield occur in the Upper Cretaceous Blackhawk Formation.

Sufco Mine

The Sufco mine has longwall and continuous miner reserves in the Upper Hiawatha and Lower Hiawatha seams, which have an average seam thickness of 10 feet. Sufco is currently mining the Upper Hiawatha seam. We plan to continue production from the Upper Hiawatha seam through the third quarter of 2021, after which time we plan to move the Sufco longwall system to Fossil Rock, which contains approximately 11.2 million tons and 32.5 million tons of high Btu, low sulfur proven and probable reserves, respectively, providing a natural replacement for the low sulfur coal currently produced from the Sufco mine's Upper Hiawatha seam. In addition, we expect to obtain a lease from the BLM through the lease by application process, described in further detail under "—Coal Reserves and Non-Reserve Coal Deposits—Reserve Acquisition Process," for the Greens Hollow tract, which contains approximately 50.5 million tons of non-reserve coal deposits accessible through our Sufco mine. Assuming our acquisition of the Greens Hollow tract, and subject to suitable demand in either domestic or international markets, we will have the ability to add a new longwall system to the Sufco mine to enable it to produce up to 7.0 million tons per year from the Lower Hiawatha seam. This production from the Sufco mine's Lower Hiawatha seam would replace the production from the Sufco mine's Upper Hiawatha seam and would be in addition to the 4.0 million tons of coal produced per year from the Fossil Rock reserves.

The expected life of mine sequence for the Sufco mine and Greens Hollow tract is set forth below:

Area	Start Date	Finish Date	Coal Seam
West Lease	February 2015	September 2017	Upper Hiawatha
Quitchupah	February 2017	September 2021	Upper Hiawatha
Greens Hollow(1)	December 2020	August 2033	Lower Hiawatha

(1) Greens Hollow is owned by the BLM and has not yet been offered for lease. We expect to lease this property through the lease by application process with the BLM. Please read "—Coal Reserves and Non-Reserve Coal Deposits—Reserve Acquisition Process."

The Sufco mine consists of a longwall, three continuous miner sections and a loadout facility located in Levan, Utah approximately 82 miles from the mine. The longwall panels are typically 1,100 feet wide and vary in length from 2,400 to 12,000 feet. The Sufco mine is producing coal with one longwall system and three continuous miner units, with a productive capacity of approximately 7.0 million tons per year.

Access at the Sufco mine is by drift portal entry from the coal seam outcrop at approximately 7,550 feet of elevation. Handling and surface facilities, including coal stockpiles, truck loading facilities, mine operations, materials supplies, warehouse and offices are all located near the mine portal. Raw coal is hauled from the mine by truck either directly to customers or to the Levan rail loadout where it is transloaded and shipped by the Union Pacific railroad. The truck-loading facility is adjacent to the mine and allows for loading approximately 8.0 million tons per year of coal via truck. The facility is equipped with a truck scale and sampling station, with coal sampled automatically as trucks exit the loadout. The facility is capable of loading two 43-ton trucks per minute and loading 800 to 900 trucks per 24-hour period. As necessary to meet customer requirements, we selectively wash a portion of the

coal produced from the Sufco mine at our 400 ton-per-hour Castle Valley preparation plant ("Castle Valley Prep Plant"), which is located at the Savage Energy Terminal. In 2006, we invested approximately $5.6 million to upgrade the Castle Valley Prep Plant, which has been leased to us through 2016 and will automatically renew for additional one year periods unless either party provides notice of termination not less than three months prior to a renewal period. Lease payments consist of a fixed fee plus a variable fee based on throughput.

We have a coal storage and blending facility located approximately 11 miles from the Sufco mine. The facility provides approximately 1.4 million tons of stockpile capacity. Its location allows for surge storage capacity should market conditions warrant increased production at the Sufco mine and facilitates additional coal blending flexibility to meet customer requirements.

The Levan rail loadout, which is located 82 miles from the Sufco mine, maintains 1.2 million tons of stockpile capacity in three separate stockpiles with blending capabilities to meet customer specifications. The Levan rail loadout is capable of railcar loading at 4,000 tons per hour and has sufficient rail loop siding capacity to accommodate unit trains of 104 railcars. For the years ended December 31, 2014 and 2013, we shipped 2.7 million tons and 2.8 million tons, respectively, through the Levan rail loadout. The Salina yard is a truck loadout and surge yard for truck direct customers. The loadout has two piles, one with 0.2 million tons of stockpile capacity and one with 0.5 million tons of stockpile capacity. The truck loading capacity is approximately 20 trucks per hour.

In 2012, we entered into an agreement with State of Utah for the construction of the Quitchupah Road. The Quitchupah Road reduced the truck haul distance from the Sufco mine to PacifiCorp's Hunter Power Plant, the largest customer of Sufco mine coal, by 23 miles, resulting in estimated savings of $2.32 per ton delivered. Our coal storage and blending facility is also located near the Quitchupah Road, which further enhances the transportation, blending and coal storage flexibility of our Sufco mine. The Quitchupah Road was completed in 2013.

Distances (via truck) from the Sufco mine to key customers and transloading facilities are set forth in the table below:

Origination	Destination	Distance (miles)
Sufco	Hunter Power Plant	39
Sufco	Huntington Power Plant	62
Sufco	IPA Power Plant	120
Sufco	Savage Energy Terminal	71

The Savage Energy Terminal, which is owned and operated by Savage, transloads coal from all three of our mines on a price-per-ton basis. Our transloading agreement with Savage extends into 2017 and will be automatically renewed annually unless either party provides notice of termination to the other party. The Savage Energy Terminal has an annual throughput capacity of approximately 8.0 million tons, and is capable of loading 10,000-ton unit trains at 6,500 tons per hour. The storage capacity at the facility is approximately 2.0 million tons. The Savage Energy Terminal is located on the Castle Valley spur of the Union Pacific rail line, which connects to the Union Pacific railroad mainline near Wellington, Utah. As of December 31, 2014, we ship approximately 500,000 tons of Sufco mine coal through the Savage Energy Terminal per year.

Skyline Mine

The Skyline mine includes longwall mineable underground reserves in the Lower O'Connor A, Lower O'Connor B and Flat Canyon seams, which have an average seam thickness of 10 feet. Skyline is currently mining the Lower O'Connor A seam in the Wasatch Plateau coalfield. We plan to continue production of the Lower O'Connor A seam through 2017. After completion of this area, we plan to

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move into the Flat Canyon tract, which contains approximately 14.2 million tons and 15.2 million tons of proven and probable reserves, respectively, and which we expect to mine through 2029.

The expected life of mine sequence for the Skyline mine is set forth below:

Area	Start Date	Finish Date	Coal Seam
North of Graben 1	January 2010	April 2017	Lower O'Connor A
South of Graben 2	October 2016	May 2018	Lower O'Connor A
Flat Canyon tract(1)	July 2017	January 2029	Lower O'Connor A
			Lower O'Connor B
			Flat Canyon

(1) On June 17, 2015, we were notified by the BLM, as part of the lease by application process, that we submitted the only bid in the competitive lease sale of the Flat Canyon tract held on June 17, 2015. On June 19, 2015, we were notified by the BLM, as part of the lease by application process, that our bid met or exceeded the BLM's estimate of the fair market value of the tract. The issuance by the BLM of the lease of the Flat Canyon tract remains subject to a 30-day antitrust review of the U.S. Department of Justice. The leasing action could also be challenged in the Department of Interior's Board of Land Appeals or in federal district court. The May 15, 2015 Notice of Lease Sale of the Flat Canyon tract prompted letters by several non-governmental organizations objecting to the lease sale on, among other things, environmental grounds. Please read "—Coal Reserves and Non-Reserve Coal Deposits—Reserve Acquisition Process."

The Skyline mine consists of a longwall, two continuous miner sections and a loadout facility. The longwall panels are typically 850 feet wide and vary in length from 1,800 feet to 6,800 feet, depending upon prevailing geological conditions and factors. Gate roads are developed on a two-entry system utilizing a yield pillar design. The Skyline mine is producing coal with one longwall system and two continuous miner units, with a productive capacity of approximately 4.5 million tons per year.

Access to the Skyline mine is by drift portal entry at approximately 8,500 feet of elevation, making Skyline the highest elevation active coal mine portal in the United States. Surface and handling facilities, including coal stockpiles, mine operations, materials supplies, warehouse and mine offices, are located at the mine portal. Rail-loading facilities are located on the Union Pacific railroad spur near the mine, supplied through a 2.2-mile long overland tubular conveyor. Skyline's surface facilities include raw coal storage capacity of 300,000 tons and a run of mine silo with an additional 8,000 tons of storage capacity. At the rail loadout, a 40,000-ton capacity stockpile is flanked with two 15,000-ton capacity silos facilitating efficient loading of railcars.

Raw coal from the Skyline mine is transported directly by an overland conveyor belt system to the Skyline truck and rail loadout facility and then shipped to customers by truck or the Union Pacific railroad. We selectively wash a portion of the coal produced from the Skyline mine at the Castle Valley Prep Plant. The Skyline loadout facility is located on the Scofield spur of the Union Pacific railroad 2.2 miles from the mine. It receives coal through an enclosed tubular overland conveyor system that transports coal at rates up to 1,400 tons per hour. The Skyline mine is the only operating underground coal mine in Utah that can load directly into a train without the use of trucks. The loadout facility is capable of loading railcars at the rate of 5,000 tons per hour and is served by the Union Pacific railroad. The Skyline mine's conveyor belt system is a single flight conveyor that is 2.2 miles long and drops 600 feet in elevation from the tail pulley to the head pulley. The belt travels in a west-to-east direction from the Skyline mine crusher building to the existing rail loadout. The pipe conveyor includes elevated sections that allow for animal migration. The truck loading capacity for the Skyline mine is approximately 230 trucks per day.

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Distances (via truck) from the Skyline mine to key customers and transloading facilities are set forth in the table below:

Origination	Destination	Distance (miles)
Skyline	Hunter Power Plant	79
Skyline	Huntington Power Plant	75
Skyline	Savage Energy Terminal	51

In the year ended December 31, 2014, we did not ship Skyline mine coal through the Savage Energy Terminal.

Dugout Canyon Mine

The Dugout Canyon mine includes both longwall and continuous miner reserves in the Gilson and Rock Canyon seams in the Book Cliffs coalfield, which have an average seam thickness of 7.2 and 7.5 feet, respectively. Dugout Canyon also has potential reserves in the adjacent Gilson Northwest seam. Future expansion opportunities in the Gilson Northwest seam are being evaluated.

The Dugout Canyon mine recently completed mining the last longwall panel in the Gilson seam in the south section of the mine and began retreating from this area in the first quarter of 2013. As of January 2015, two continuous miner units were mining a reserve block in the Rock Canyon seam. Subject to suitable demand in either domestic or international markets, we have the ability to add a third continuous miner unit to the Dugout Canyon mine without any additional surface infrastructure, and increase its productive capacity from approximately 1.1 million tons per year to approximately 1.5 million tons per year. We plan to continue production from the Rock Canyon seam through December 2020. After completion of this area, we plan to move into Gilson North 4, which we expect to mine through July 2026.

The expected life of mine sequence for the Dugout Canyon mine is set forth below:

Area	Start Date	Finish Date	Coal Seam
Rock Canyon	February 2013	December 2020	Rock Canyon
Gilson North 4	June 2020	July 2026	Gilson
North West 8	February 2024	March 2034	Gilson

The Dugout Canyon mine consists of one continuous miner section and a truck loadout facility. Access to the Dugout Canyon mine is by drift portal entry at approximately 7,100 feet of elevation. Coal handling and surface facilities, including stockpiles, truck loadouts, mine operations, materials supplies, warehouse and offices, are located near the mine portal. Dugout Canyon's surface facilities include raw coal storage capacity of 130,000 tons and a raw coal stockpile area with live reclaim to the truck loadout. Dugout Canyon's truck loadout is adjacent to mine operations. The facility allows for the loading of 11 to 12 million tons per year of coal via truck. The facility is equipped with truck scales and a sampling station, with coal sampled automatically as trucks exit the loadout. The facility typically loads 150 to 200, 43-ton trucks per day.

Raw coal from the Dugout Canyon mine is trucked to local markets and to the Savage Energy Terminal, which is approximately 20 miles from the mine, where it can be shipped via the Union Pacific and Burlington Northern Santa Fe railroads. We selectively wash a portion of the coal produced from the Dugout Canyon mine at the Castle Valley Prep Plant, and as of December 31, 2014, we ship approximately 600,000 tons of Dugout Canyon mine coal through the Savage Energy Terminal per year.

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Fossil Rock Reserves

On June 5, 2015, we acquired the Fossil Rock reserves from an affiliate of PacifiCorp, which increase our proven and probable reserves by an estimated 11.2 million tons and 32.5 million tons, respectively. We plan to begin development of the Fossil Rock reserves in 2017, begin production from the Fossil Rock reserves with continuous miner units in 2018 and spend approximately $100.0 million ratably between 2017 and 2021 to move the Sufco mine longwall system to Fossil Rock for operation in 2021. At full production, we expect to produce approximately 4.0 million tons of coal per year from the Fossil Rock reserves from 2017 through 2034. The Fossil Rock reserves are located closer to PacifiCorp's Huntington and Hunter Power Plants than our existing mines, which we believe will significantly reduce our transportation costs to this principal customer.

Distances (via truck) from the Fossil Rock reserves to key customers and transloading facilities are set forth in the table below:

Origination	Destination	Distance (miles)
Fossil Rock	Hunter Power Plant	15
Fossil Rock	Huntington Power Plant	30
Fossil Rock	Savage Energy Terminal	40

Transportation and Logistics

Our coal is transported to domestic customers and export terminal facilities by truck and rail. For the years ended December 31, 2014 and 2013, approximately 4.1 million tons and 3.8 million tons, respectively, of our production was shipped via truck to customers, and approximately 7.4 million tons and 6.3 million tons, respectively, of our production was shipped via rail (either to our domestic customers or to U.S. West Coast export terminals). Our sponsor recently entered into a three-year contract for the transportation of our coal via truck from the Sufco and Skyline mines to PacifiCorp, IPA and various loadout facilities. Under a coal haulage agreement entered into in 2004 with Savage, we are required to utilize Savage to transport all of our coal via truck from the Dugout Canyon mine.

The high productivity of our strategically-located mines, together with our sponsor's transportation and logistics network, enables us to deliver coal to key domestic markets, and to our key customers, at a lower cost per Btu compared to coal from other Western Bituminous coal producers, coal from other basins and natural gas, even when adjusting for different heat rate efficiencies between coal and natural

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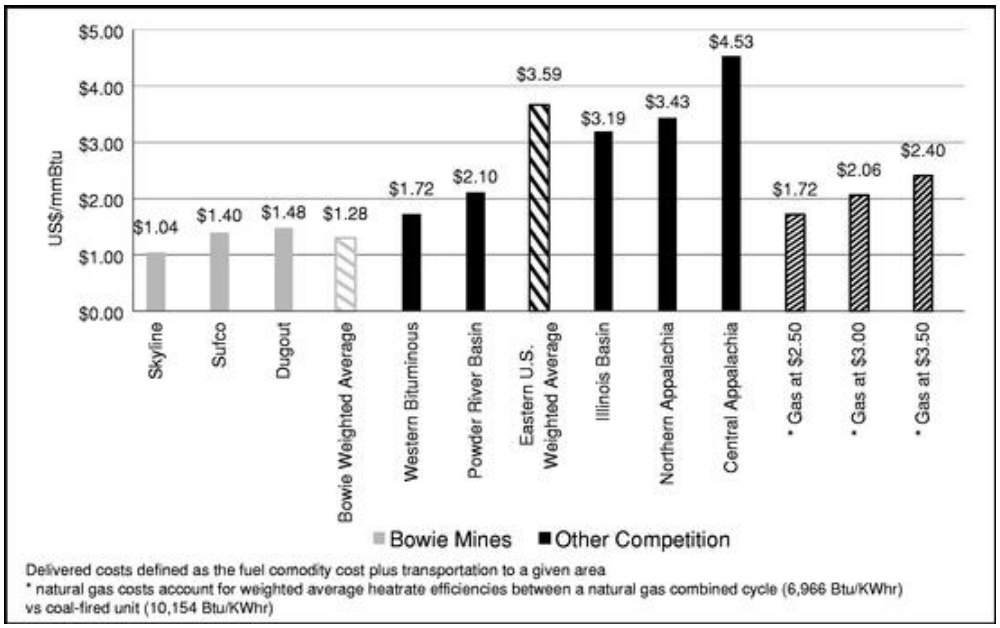
gas-fired power plants. According to Wood Mackenzie, our coal is cost competitive relative to other sources when delivered to Utah, as illustrated in the chart below:

Illustrative Cost Comparison: To Utah

Total Delivered Cost (US$/million Btu)



Source: Wood Mackenzie, May 2015.

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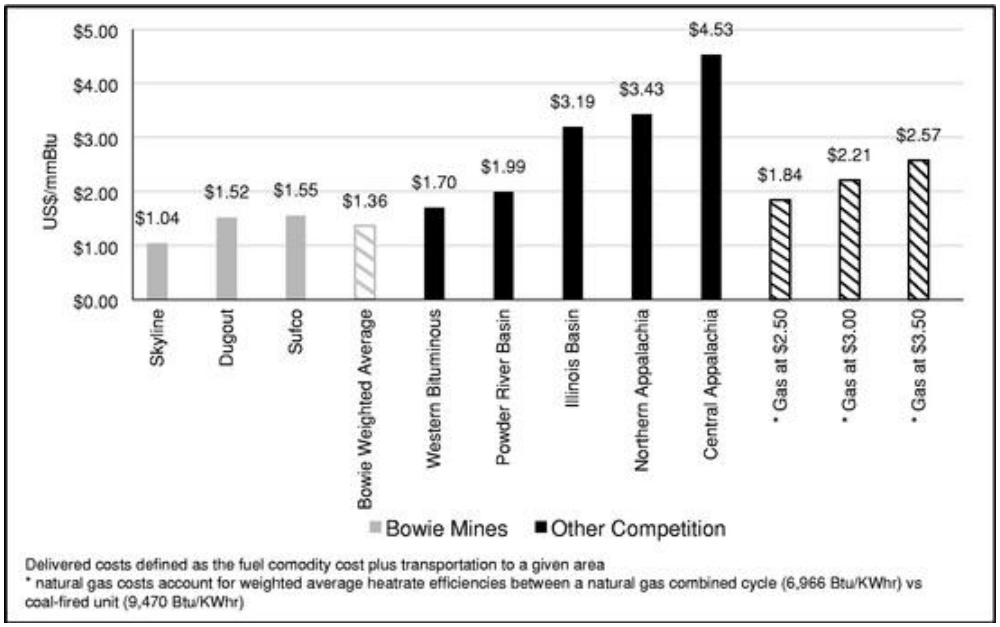
According to Wood Mackenzie, our coal is cost competitive to our key customers relative to other sources, as illustrated in the charts below:

Illustrative Cost Comparison: To IPA

Total Delivered Cost (US$/million Btu)



Source: Wood Mackenzie, May 2015.

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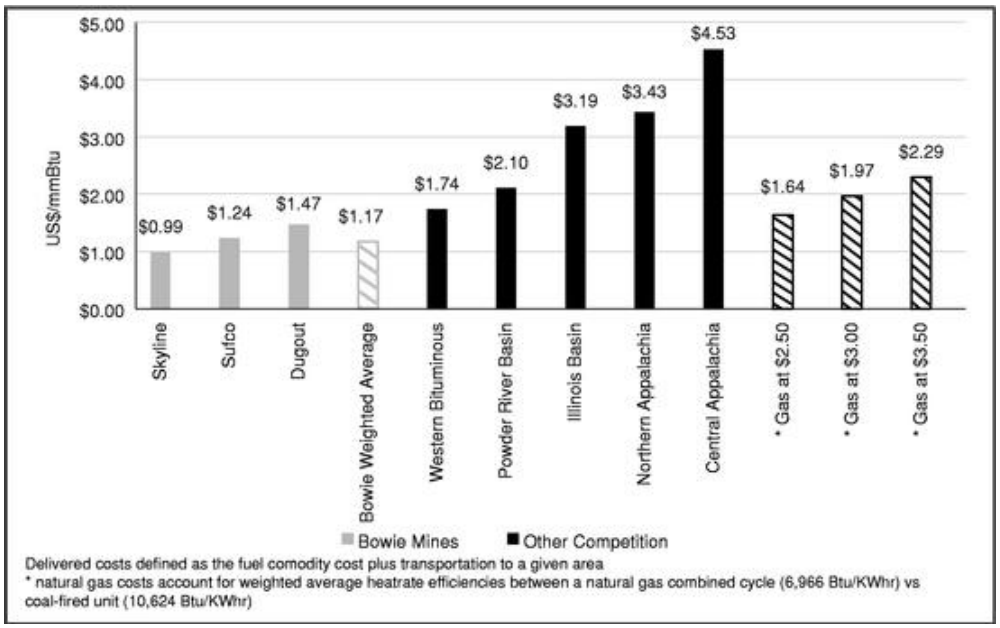
Illustrative Cost Comparison: To PacifiCorp

Total Delivered Cost (US$/million Btu)



Source: Wood Mackenzie, May 2015.

We are the only coal producer with contracted U.S. West Coast export capacity, with aggregate throughput capacity of approximately 5.7 million tons through the Port of Stockton, California and the Levin-Richmond Terminal. There are currently only three U.S. West Coast terminals that export coal: the Port of Stockton, California and the Levin-Richmond Terminal, each of which is leased by our sponsor, as well as the Port of Long Beach, which is controlled by an affiliate of Oxbow Carbon, LLC, a company that no longer produces coal. Our sponsor's terminal contract with Metropolitan Stevedore Company with respect to the Port of Stockton expires on December 31, 2019, and our sponsor's terminal contract with Levin-Richmond Terminal Corp. expires on December 31, 2015. In addition, our coal has been exported through a brokerage arrangement through the Port of Long Beach, California. This capacity, coupled with our railway access, enables us to transport coal at highly competitive rates. By leveraging Trafigura AG's and its affiliates' significant expertise in the coal export market and existing commodities trading infrastructure, we are able to sell our coal internationally to a variety of intermediary and end users in the power generation business.

Pursuant to a Coal Services Agreement, Trafigura AG is the exclusive provider of certain sales, marketing, administrative and other services to us and our sponsor for the production life of our reserves. We and our sponsor pay Trafigura AG a sales fee equal to a percentage of the price paid per ton (FOB mine) delivered under the Coal Services Agreement, provided that the sales fee may be increased for export sales of coal above certain price per ton thresholds. Trafigura AG has the right to terminate the Coal Services Agreement upon 180 days' notice. We and our sponsor have a right to terminate the Coal Services Agreement with respect to any mine only upon a sale of such mine to a third party. For the year ended December 31, 2014, our sponsor paid Trafigura AG approximately $3.6 million pursuant to the Coal Services Agreement.

Upon the closing of this offering, we expect to terminate our existing Coal Services Agreement among CFC, our sponsor and Trafigura AG and to enter into a new Coal Services Agreement among

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our operating company and its subsidiaries, our sponsor and Trafigura AG, with substantially the same terms and conditions as the existing Coal Services Agreement.

Coal Reserves and Non-Reserve Coal Deposits

We base our coal reserve estimates on engineering, economic and geological data assembled and analyzed by our staff. These estimates are also based on the expected cost of production and projected sale prices and assumptions concerning the permitability and advances in mining technology. The estimates of coal reserves and non-reserve coal deposits as to both quantity and quality are periodically updated to reflect the production of coal from the reserves, updated geologic models and mining recovery data, coal reserves recently acquired and estimated costs of production and sales prices. Acquisitions or sales of coal properties will also change these estimates. Changes in mining methods may increase or decrease the recovery basis for a coal seam, as will plant processing efficiency tests. We maintain reserve and non-reserve coal deposit information in secure computerized databases, as well as in hard copy. The ability to update and/or modify the estimates of our coal reserves and non-reserve coal deposits is restricted to a few individuals and the modifications are documented.

All of our reserves are considered high Btu coal, with Btu content ranging between 10,916 and 11,844 per pound and low sulfur, with sulfur content ranging between 0.43% and 0.80%. On a pro forma basis, after giving effect to the closing of the Utah Transaction and the BLM's issuance of the Flat Canyon lease to us, the following table presents our estimated coal reserves as of December 31, 2014:

	Proven Reserves		Probable Reserves				
Mine	Assigned	Unassigned	Assigned	Unassigned	Total(1)	Btu per pound(2)	Sulfur (%)
	(in millions of tons)						
Sufco	18.7	14.3	16.8	11.4	61.2	10,916	0.43
Skyline(3)	32.5	0.9	21.1	0.3	54.8	11,542	0.44
Dugout Canyon	9.2	1.5	1.2	0.4	12.3	11,844	0.80
Fossil Rock(4)	11.2	—	29.1	3.4	43.7	11,550	0.57
Total all mines					172.0		

(1) All of our proven and probable reserves are thermal (or steam) coal. We own 0.7 million tons of proven and probable reserves at each of the Sufco and Skyline mines. Our other reserves are held by lease. On a weighted-average basis, all our coal is compliance coal.

(2) All Btus per pound are expressed on an as-received basis, including total moisture.

(3) On June 17, 2015, we were notified by the BLM, as part of the lease by application process, that we submitted the only bid in the competitive lease sale of the Flat Canyon tract held on June 17, 2015. On June 19, 2015, we were notified by the BLM, as part of the lease by application process, that our bid met or exceeded the BLM's estimate of the fair market value of the tract, which contains approximately 14.2 million tons and 15.2 million tons of proven and probable reserves, respectively. The issuance by the BLM of the lease of the Flat Canyon tract remains subject to a 30-day antitrust review of the U.S. Department of Justice. The leasing action could also be challenged in the Department of Interior's Board of Land Appeals or in federal district court. The May 15, 2015 Notice of Lease Sale of the Flat Canyon tract prompted letters by several non-governmental organizations objecting to the lease sale on, among other things, environmental grounds. Please read "—Reserve Acquisition Process."

(4) We acquired the Fossil Rock reserves from an affiliate of PacifiCorp on June 5, 2015. Please read "—Overview."

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On a pro forma basis, after giving effect to our anticipated lease of the Greens Hollow tract from the BLM, the following table presents our estimated non-reserve coal deposits as of December 31, 2014:

Mine	Non-Reserve Coal Deposits(1) (in millions of tons)
Greens Hollow tract	50.5
Total	50.5

(1) Statements of non-reserve coal deposits for the Greens Hollow tract rely solely on the estimates of management and have not been prepared or audited by Norwest.

"Reserves" are defined by the SEC Industry Guide 7 as that part of a mineral deposit that could be economically and legally recovered or produced at the time of the reserve determination. Industry Guide 7 divides reserves between "proven (measured) reserves" and "probable (indicated) reserves" which are defined as follows:

- "Proven (measured) reserves." Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

- "Probable (indicated) reserves." Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling, and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

Our coal reserve estimates include both assigned and unassigned reserves.

Non-reserve coal deposits are coal-bearing bodies that have been sufficiently sampled and analyzed in trenches, outcrops, drilling and underground workings to assume continuity between sample points, and therefore warrant further exploration stage work. However, this coal does not qualify as a commercially viable coal reserve as prescribed by standards of the SEC until a final comprehensive evaluation based on unit cost per ton, recoverability and other material factors concludes legal and economic feasibility. Non-reserve coal deposits may be classified as such by either limited property control or geological limitations, or both.

Periodically, we retain outside experts to independently verify our coal reserve and non-reserve coal deposit estimates. The most recent audit by an independent engineering firm of our coal reserve estimates was completed by Norwest, as of December 31, 2014 and covered all of the coal reserves that we controlled as of such date, together with the Fossil Rock reserves and the proven and probable reserves associated with the Flat Canyon tract. As of December 31, 2014, on a pro forma basis giving effect to the Utah Transaction and our anticipated lease of the Flat Canyon tract and the Greens Hollow tract from the BLM, we would have controlled over 88 million tons and 84 million tons of proven and probable coal reserves, respectively, with an average heat content range of 10,916 to 11,844 Btu per pound and an estimated 50.5 million tons of non-reserve coal deposits with an average heat content range of 10,900 to 11,200 Btu per pound. Statements of non-reserve coal deposits for the Greens Hollow tract rely solely on the estimates of management and have not been prepared or audited by Norwest.

Our coal reserve estimates include reserves that can be economically and legally recovered or produced at the time of their determination. In determining whether our reserves meet this standard,

we take into account, among other things, the possible necessity of revising a mining plan, changes in estimated future costs, changes in future cash flows caused by changes in costs required to be incurred to meet regulatory requirements and obtain mining permits, variations in quantity and quality of coal, and varying levels of demand and their effects on selling prices. Further, the economics of our reserves are based on market conditions, including contracted pricing, market pricing and overall demand for our coal. Thus, the actual value at which we no longer consider our reserves to be economic varies depending on the length of time in which the specific market conditions are expected to last. We consider our reserves to be economic at a price in excess of our cash costs to mine the coal and our ongoing replacement capital. Because we do not regularly wash our coal, our reserve estimates do not include potential losses from the washing process.

A substantial amount of our coal is produced from mineral reserves leased from various land owners. Our main lessor is the U.S. government, from which we lease coal under terms set by Congress and administered by the BLM through the process described below under "—Reserve Acquisition Process." These leases are generally for an initial term of ten years but may be extended by diligent development and mining of the reserves until all economically recoverable reserves are depleted. We have met the diligent development requirements for substantially all of our federal leases either directly through production, by including the lease as a part of a logical mining unit with other leases upon which development has occurred, or by paying an advance royalty in lieu of continued operations. Annual production on these federal leases must total at least 1% of the original amount of coal in the entire logical mining unit. In addition, royalties are generally payable monthly at a rate of 8% of the gross realization for coal produced using underground mining methods. Many BLM leases also require payment of a lease rental or minimum royalty, payable either at the time of execution of the lease or in periodic installments.

The remainder of our coal is generally leased from the State of Utah, land holding companies and various individuals. The duration of these leases varies. Typically, the lease terms are automatically extended as long as active mining continues. Royalty payments are generally based upon a specified rate per ton or a percentage of the gross realization from the sale of the coal.

Title to our owned or leased properties and mineral rights is not usually verified unless we are required by our lenders to obtain title policies or title opinions. In August 2013, in connection with the execution of our sponsor’s Senior Secured Credit Facilities, title polices and title opinions were obtained by our sponsor on certain of our owned and leased surface and mineral rights. We have not obtained any title policies or title opinions with respect to the Fossil Rock reserves but will be required to do so in connection with the offering of the New Notes.

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We own 0.7 million tons of proven and probable reserves at each of the Sufco and Skyline mines. Our other reserves are held by lease. Set forth below is a description and summary of the leased mineral reserves for the life of mine sequence for each mine:

	Sufco Mine Leases			
Lessor	Effective Date	Expiration Date	Royalty Rate	Total Lease Acres
BLM	9/11/1941	9/10/2021	8% and $0.35/ton after 6.93 million tons removed	3,079.83
BLM	1/1/1979	12/31/2019	11.68%	716.51
BLM	3/1/1962	2/28/2022	8%	480.00
BLM	10/1/1981	9/30/2021	8% and $0.35/ton after 6.93 million tons removed	1,953.73
BLM	7/1/1989	6/30/2019	8% and $0.35/ton after 6.93 million tons removed	8,826.34
BLM	6/1/1966	4/30/2016	8%	240.00
BLM	10/1/1999	9/30/2019	8%	5,694.66
State of Utah School and Institutional Trust Lands Administration(1)	10/1/2004	9/30/2024	8%	2,134.19
BLM(2)	TBD	TBD	8% estimated	TBD

(1) We have applied to amend this lease to cover an additional 419.65 acres. The application is subject to applicable regulatory approvals.

(2) The Greens Hollow tract is owned by the BLM and has not yet been offered for lease. We expect to lease this property through the lease by application process with the BLM. Please read "—Reserve Acquisition Process."

	Skyline Mine Leases			
Lessor	Effective Date	Expiration Date	Royalty Rate	Total Lease Acres
BLM	5/1/1966	5/1/2016	8%	1,532.70
BLM	3/1/1962	2/28/2022	8%	279.40
BLM	10/1/1964	10/1/2024	8%	520.00
BLM	9/1/1965	8/31/2015	8%	2,489.32
BLM	2/1/1964	1/31/2024	8%	557.22
BLM	9/1/1996	8/30/2016	8% and $0.40/ton in tract 2	4,061.52
Carbon County	5/1/2004	4/30/2024	8%	80.00
James O. Tracy, Jr. & Linda D. Tracy	5/22/1998	5/21/2018	2% or $0.30/ton whichever is greater	346.68
David G. & Rene L. Cunningham	5/22/1998	5/21/2018	2% or $0.30/ton whichever is greater	346.68
Collard Family Trust	5/30/1998	5/29/2018	4% or $0.60/ton whichever is greater for owned; $0.05/ton or $2,010/year whichever is greater for not owned	1,003.67
Carbon County	10/5/1977	7/31/2022	8%	1,200.00
BLM(1)	TBD	TBD	8%	2,692.16

(1) On June 17, 2015, we were notified by the BLM, as part of the lease by application process, that we submitted the only bid in the competitive lease sale of the Flat Canyon tract held on June 17, 2015. On June 19, 2015, we were notified by the BLM, as part of the lease by application process,

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that our bid met or exceeded the BLM's estimate of the fair market value of the tract. The issuance by the BLM of the lease of the Flat Canyon tract remains subject to a 30-day antitrust review of the U.S. Department of Justice. The leasing action could also be challenged in the Department of Interior's Board of Land Appeals or in federal district court. The May 15, 2015 Notice of Lease Sale of the Flat Canyon tract prompted letters by several non-governmental organizations objecting to the lease sale on, among other things, environmental grounds. Please read "—Reserve Acquisition Process."

	Dugout Canyon Mine Leases			
Lessor	Effective Date	Expiration Date	Royalty Rate	Total Lease Acres
BLM	10/1/1995	9/30/2015	8%	2,117.52
BLM	1/1/1957	12/31/2016	8%	2,881.15
BLM	1/4/1935	1/3/2015	8%	1,548.31
BLM	9/1/1982	8/30/2022	8%	440.00
State of Utah School and Institutional Trust Lands Administration	10/11/1985	10/31/2015	8%	3,640.00
State of Utah School and Institutional Trust Lands Administration	10/11/1985	10/31/2015	8%	2,212.00
State of Utah School and Institutional Trust Lands Administration	4/3/1989	10/31/2015	8%	557.20
State of Utah School and Institutional Trust Lands Administration	9/1/2000	10/31/2015	8%	2,560.00
State of Utah School and Institutional Trust Lands Administration	2/1/2007	10/31/2015	8%	320.00

	Fossil Rock Leases			
Lessor	Effective Date	Expiration Date	Royalty Rate	Total Lease Acres
State of Utah School and Institutional Trust Lands Administration(1)	1/18/2008	1/18/2028	8%	8,203.87
State of Utah School and Institutional Trust Lands Administration(1)	1/18/2008	1/18/2028	8%	600.00
BLM	7/1/1962	7/1/2022	8%	80.00
BLM	3/1/1983	3/1/2023	8%	380.00
BLM	10/1/1990	10/1/2020	8%	260.00

(1) Concurrent with the closing of the Utah Transaction, Fossil Rock Resources, LLC granted PacificCorp a 4% overriding royalty on the gross sales revenue from the sale of all coal mined from this lease, FOB the source.

Reserve Acquisition Process

A substantial amount of our coal is produced from mineral reserves leased from various land owners. Most of our leases are with the U.S. government with lease terms set by Congress and administered by the BLM. Accordingly, the federal competitive leasing process is our principal means of acquiring additional reserves. We acquire a large portion of our coal through the LBA process. Under this process, before a mining company can obtain a new federal coal lease, the company must nominate a coal tract for lease and then win the lease through a competitive bidding process. The LBA process can last anywhere from two to five years or more from the time the coal tract is nominated to the time a final bid is accepted by the BLM. After the LBA is awarded, the company then conducts the necessary testing to determine what amount can be classified as reserves and begins the process to

permit the coal for mining, which generally takes another two to five years. Third-party legal challenges, such as legal challenges filed against the BLM and the Secretary of the Interior by environmental groups with respect to the LBA process generally, or in the Uinta Basin more specifically, may result in delays and other adverse impacts on the LBA process.

To initiate the LBA process, coal producers file an application with the BLM's state office indicating interest in a specific coal tract. The BLM reviews the initial application to determine whether the application conforms to existing land-use plans for that particular tract of land and whether the application would provide for maximum coal recovery. The application is further reviewed by a regional coal team at a public meeting. Based on a review of the available information and public comment, the regional coal team will make a recommendation to the BLM whether to continue, modify or reject the application.

The BLM also allows for small tracts of coal to be acquired through the lease by modification process. A lease by modification is a non-competitive leasing process and is used in circumstances where a lessee is seeking to modify an existing federal coal lease by adding less than 960 acres in a configuration that is deemed non-competitive to other coal producers.

If the BLM determines to continue the application, a BLM-directed study under NEPA consisting of either an environmental assessment ("EA") or an Environmental Impact Statement ("EIS") is conducted at the cost of the applicant. This analysis or impact statement is subject to publication and public comment. The BLM may consult with other government agencies during this process, including state and federal agencies, surface management agencies, Native American tribes or bands, the U.S. Department of Justice or others as needed. The public comment period for an analysis or impact statement typically occurs over a 60-day period.

After the EA or EIS has been issued and a recommendation has been published that supports the lease sale of the LBA tract, the BLM schedules a public competitive lease sale. The BLM prepares an internal estimate of the fair market value of the coal that is based on its economic analysis and comparable sales analysis. Prior to the lease sale, companies interested in acquiring the lease must send sealed bids to the BLM. The bid amounts for the lease are payable in five annual installments, with the first 20% installment due when the mining operator submits its initial bid for an LBA. Before the lease is approved by the BLM, the company must first furnish to the BLM an initial rental payment for the first year of rent along with either a bond for the next 20% annual installment payment for the bid amount, or an application for history of timely payment, in which case the BLM may waive the bond requirement if the company successfully meets all the qualifications of a timely payor. The bids are opened at the lease sale. If the BLM decides to grant a lease, the lease is awarded to the company that submitted the highest total bid meeting or exceeding the BLM's fair market value estimate, which is not published. The BLM, however, is not required to grant a lease even if it determines that a bid meeting or exceeding the fair market value of the coal has been submitted. The winning bidder must also submit a report setting forth the nature and extent of its coal holdings to the U.S. Department of Justice for a 30-day antitrust review of the lease. If the successful bidder was not the initial applicant, the BLM will refund the initial applicant certain fees it paid in connection with the application process, for example the fees associated with the EA or EIS, and the winning bidder will bear those costs. Coal leases awarded through the LBA process and subject to federal leases are administered by the U.S. Department of Interior under the Federal Coal Leasing Amendment Act of 1976. Once the BLM has issued a lease, the company must next complete the permitting process before it can mine the coal. Please read "Environmental and Other Regulatory Matters—Permits."

The federal coal leasing process is designed to be a public process, giving stakeholders and other interested parties opportunities to comment on the BLM's proposed and final actions and allow third-party comments. Because of this, third parties, including non-governmental organizations, can challenge the BLM's actions, which may delay the leasing process. If these challenges prove successful or are

litigated for a prolonged period of time, a coal company's ability to bid on or acquire a new coal lease could be significantly delayed, or could cause the BLM to not offer a lease for bid at all. For example, in November 2014, two non-governmental organizations brought suit against the Secretary of the Interior and the BLM alleging that the BLM's coal leasing program is in violation of NEPA. Although the plaintiffs acknowledge that the BLM has generally complied with the requirements of NEPA with respect to individual coal leases, they assert that that the agency's failure to update its 1979 analysis of environmental impacts associated with the broader BLM federal coal management program to include the impacts of GHGs constitutes a violation of NEPA. The plaintiffs are seeking an injunction that would, if their efforts are successful, prevent the issuance of new coal leases or modifications until the BLM has satisfied the requirements of NEPA. These types of challenges create some uncertainty with respect to the timing of future LBA bids and lease acquisitions and may ultimately delay the leasing process or prevent mining operations. Even after a lease has been issued and a successful bidder has paid installment money to the BLM, legal challenges may still seek to delay or prevent mining operations. It is possible that subsequent EISs for other mines in the Uinta Basin currently underway but not yet final could be similarly challenged. There also exists the possibility of similar challenges to the permitting and licensing process, which is also a public process designed to allow public comments.

Each of our federal coal leases have an initial term of 10 or more years, renewable for subsequent 10-year periods and for so long thereafter as coal is produced in commercial quantities. The leases require diligent development within the initial term of the lease award, requiring coal extraction in commercial quantities during the initial term, as specified in each lease. At the end of an initial development period, the lessee is required to maintain continuous operations, as defined in the applicable leasing regulations. In certain cases, a lessee may combine contiguous leases into a logical mining unit. This allows the production of coal from any of the leases within the logical mining unit to be used to meet the continuous operation requirements for the entire logical mining unit. We pay to the federal government an annual rent of $3.00 per acre and production royalties (generally) of 8% of gross revenue on underground mined coal. The federal government remits approximately 50% of the production royalty payments to the state after deducting administrative expenses. Some of our mines are also subject to coal leases with the State of Utah and have different terms and conditions that we must adhere to in a similar way to our federal leases. Under these federal and state leases, if the leased coal is not diligently developed during the initial development period or if certain other terms of the leases are not complied with, including the requirement to produce a minimum quantity of coal or pay a minimum production royalty, if applicable, the BLM or the applicable state regulatory agency can terminate the lease prior to the expiration of its term.

Some of the coal we lease from the U.S. federal government comes from "split estate" lands in which one party, such as the federal government, owns the coal and a private party owns the surface. In order to mine the coal we acquire, we must acquire rights to mine from certain owners of the surface lands overlying the coal. Certain federal regulations provide QSOs with the ability to prohibit the BLM from leasing its coal. If the land overlying a coal tract is owned by a QSO, federal laws prohibit us from leasing the coal tract without first securing surface rights to the land, or purchasing the surface rights from the QSO, which would allow us to conduct our mining operations. Furthermore, the state permitting process requires us to demonstrate surface owner consent for split estate lands before the state will issue a permit to mine coal. This consent is separate from the QSO consent required before leasing federal coal. The right of QSOs and certain other surface owners allows them to exercise significant influence over negotiations and prices to acquire surface rights and can delay the federal coal lease or permitting processes or ultimately prevent the acquisition of the federal coal lease or permit over that land entirely. QSOs may own land adjacent to or near our existing mines that may be attractive acquisition candidates for us.

Most of the coal we have acquired from private third parties is in the form of coal leases obtained through private negotiations with one or more third parties. These leases generally include, among

other terms and conditions, a set term of years with the right to renew the lease for a stated period and royalties to be paid to the lessor as a percentage of the sales price. These leases may require payment of a lease bonus or minimum royalty, payable either at the time of execution of the lease or in periodic installments, and a minimum production of coal from the leased areas in order to hold the leases by active production. We believe that the term of years will allow the recoverable reserve to be fully extracted in accordance with our projected mine plan. Consistent with industry practice, we conduct only limited investigations of title to our coal properties prior to leasing. Title to properties leased from private third parties is not usually verified unless we are required by our lenders to obtain title policies or title opinions.

Customers

General

We sell coal directly through coal supply agreements with our customers and indirectly to customers through our sponsor. In connection with the closing of this offering, we expect to enter into a coal supply agreement with our sponsor pursuant to which it will purchase substantially all of our coal on substantially the same terms as our sponsor's agreements with our end customers. References in this prospectus to "our coal supply agreements" refer to (i) coal supply agreements between us and our customers, (ii) coal supply agreements between us and our sponsor and (iii) coal supply agreements between our sponsor and the end customers of our coal. References in this prospectus to "our customers" refer to customers purchasing coal directly from us and customers purchasing our coal through our sponsor.

A large portion of our coal is sold to PacifiCorp and IPA, two large regional utilities located in close proximity to our mines. For the years ended December 31, 2014 and 2013, we derived approximately 52% and 55%, respectively, of our total coal revenues from sales of coal to PacifiCorp and IPA. For the year ending December 31, 2015, we expect to derive approximately 71% of our total coal revenues from sales of coal to PacifiCorp and IPA. If these two customers were to significantly reduce their purchases of coal from us, or if we were unable to sell coal to these customers on terms as favorable to us as the terms under our current coal supply agreements, our results of operations may be materially adversely affected.

In addition to our sales to PacifiCorp and IPA, we expect to sell approximately 2.0 million tons each year to our domestic industrial customers. While our coal supply agreements with these industrial customers are typically short-term in nature (12 to 18 months in duration), most of these customers have been purchasing our coal for over 25 years and, as such, we expect these customers to continue to renew their coal supply agreements with us in the future.

The coal supply agreements with our end customers often result from competitive bidding and extensive negotiations. Consequently, the terms of these agreements may vary significantly by customer, including with respect to price adjustment features, coal quality requirements, quantity adjustment mechanisms, permitted sources of supply, future regulatory changes, extension options, force majeure provisions and termination and assignment provisions.

Most of our coal supply agreements contain provisions requiring delivery of coal within certain ranges for specific coal characteristics such as heat content, sulfur, ash, grindability, chlorine and ash fusion temperature. Failure to meet these conditions could result in economic penalties, purchasing replacement coal in a higher priced open market, rejection of deliveries or termination of the agreements, at the election of the customer. Although the volume to be delivered under a long-term agreement is stipulated, the parties may vary the timing of delivery within specified limits. Our coal supply agreements also typically contain force majeure provisions allowing for the suspension of performance by the parties for the duration of specified events beyond the control of the affected

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party. Some agreements may terminate upon continuance of an event of force majeure for an extended period.

The international thermal coal market has also been a substantial part of our business with sales to end users in Mexico, Japan, China, Guatemala, Chile and Hawaii. For the years ended December 31, 2014 and 2013, we exported approximately 21% and 9%, respectively, of our coal production into these international markets. Trafigura AG is the exclusive marketer of our uncommitted coal. Almost all of our export sales are made under contracts with a duration of less than one year.

On a pro forma basis, after giving effect to the closing of the Utah Transaction, the following table describes our contracted position (in millions of tons) for certain key customers for 2015, 2016, 2017 and 2018 as of December 31, 2014. In addition to the contracts described below, we also sell coal domestically to other industrial companies and internationally, through Trafigura AG, to a variety of intermediary and end-users in the power generation business.

Coal Supply Agreements with Key Customers

	Contracted Position Minimum/Maximum(2)				Projected Coal Sales(3)				
Customer(1)	2015	2016	2017	2018	2015(3)	2016	2017	2018	Contract Expiration
	(million tons)				(million tons)				
PacifiCorp:									
Hunter	2.5–4.5	2.5–4.5	2.5–4.5	2.5–4.5	3.8	3.5	4.1	4.0	2020
PacifiCorp:									
Huntington(4)	2.0–3.0	2.0–3.0	2.0–3.0	2.0–3.0	1.8	2.1	2.5	2.5	2029
IPA Contract									
No 1	2.0–2.2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2024
IPA Contract									
No 2(5)	0.5–1.0	0.5–1.0	0.5–1.0	0.5–1.0	0.31	0.75	0.75	0.75	2024
Total	7.0–10.7	7.0–10.5	7.0–10.5	7.0–10.5	7.91	8.35	9.35	9.25	

(1) References in this prospectus to "our coal supply agreements" includes (i) coal supply agreements between us and our customers, (ii) coal supply agreements between us and our sponsor and (iii) coal supply agreements between our sponsor and the end customers of our coal. These coal supply agreements include the PacifiCorp: Hunter, PacifiCorp: Huntington, IPA Contract No. 1 and IPA Contract No. 2 coal supply agreements. Our sponsor is the direct counterparty to these agreements.

(2) Except for IPA Contract No. 1, our coal supply agreements with key customers provide for sales of a minimum amount of coal per year and a maximum amount of coal per year.

(3) Reflects our anticipated coal sales based on our historical relationship with the customer and management's knowledge of the customer's coal requirements and the customer's other coal supply arrangements.

(4) Pursuant to the terms of the Huntington coal supply agreement, PacifiCorp has the right through 2020 to purchase coal under certain legacy contracts with other coal producers. PacifiCorp currently has the right to purchase up to 0.6 million tons in 2016 and 0.3 million tons of coal in 2017 under such legacy contracts. In the event that PacifiCorp purchases coal under such legacy contracts, the annual minimum quantity may fall below 2.0 million tons of coal to the extent of such purchases.

(5) For 2015, we expect 0.44 million tons of sales for IPA Contract No. 2 to be sourced from the Bowie #2 mine, which is owned by our sponsor. Our sponsor will retain the Bowie #2 mine and any related assets after the IPO Reorganization.

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PacifiCorp

We have two long-term coal supply agreements with PacifiCorp, one for PacifiCorp's Hunter Power Plant and one for PacifiCorp's Huntington Power Plant, each of which includes fixed pricing, subject to price escalators and adjustments as described below. The PacifiCorp agreements provide for aggregate sales of a minimum of 4.5 million tons per year and a maximum of 7.5 million tons per year. The PacifiCorp coal supply agreements include provisions that require the customer to compensate us (either in the form of a shortfall fee or by purchasing any shortfall tonnage during the following contract year) in the event the customer does not take delivery of the minimum annual volume of coal specified in the applicable coal supply agreement. The PacifiCorp coal supply agreements include price escalators, as well as provisions that allow us to pass through (by means of a price increase) certain increases in mining and transportation costs. A minimum of 2.5 million tons, and a maximum of 4.5 million tons, of the coal to be delivered to PacifiCorp is subject to a price reset effective January 1, 2016 based on a weighted average formula that takes into account a base price, the price of coal sold by us in 2015 (adjusted for delivery FOB the railcar) and certain index pricing. Based on this formula, and upon a previously determined "ceiling" price for the 2016 calendar year, we expect this price reset for the 2016 calendar year to result in a price slightly below that for the 2015 calendar year.

The Hunter Power Plant coal supply agreement requires PacifiCorp to purchase a minimum of 2.5 million tons and a maximum of 4.5 million tons of our coal per year through December 31, 2020. The Huntington Power Plant coal supply agreement, which was executed on December 12, 2014 as part of the Utah Transaction and became effective upon the closing of the same, requires PacifiCorp to purchase all of its coal requirements for the Huntington Power Plant from us through December 31, 2029, with a minimum of 2.0 million tons of coal per year and maximum of 3.0 million tons of coal per year, subject to certain exceptions to the minimum tonnage requirements through 2020. From December 12, 2014 until the closing of the Utah Transaction, we sold coal to PacifiCorp for the Huntington Power Plant under an interim coal supply agreement (the terms of which, other than its duration, were substantially the same as those in the coal supply agreement that became effective upon the closing of the Utah Transaction).

The PacifiCorp coal supply agreements permit the customer (or, in the case of the Huntington Power Plant, the customer and us) to terminate the agreement in the event changes in regulations affecting the coal industry increase the price of coal beyond a specified amount, subject to the non-terminating party's right to elect to continue the agreement by bearing such additional costs above the specified amount. In addition, PacifiCorp may terminate if certain regulations or other governmental actions affect, in the case of the Huntington Power Plant, PacifiCorp's ability to use the minimum tonnage, or increase, in the case of the Hunter Power Plant, PacifiCorp's cost of handling and consuming coal above a specified threshold, subject to our right to continue each agreement for a specified period and to supply coal under such agreement with certain price adjustments. The PacifiCorp coal supply agreements contain force majeure provisions allowing for the suspension of performance by either party for the duration of specified events to the extent made necessary by any such force majeure event.

IPA

We have two long-term coal supply agreements with IPA, each for IPA's Delta Power Plant and each of which includes fixed pricing, subject to price escalators and adjustments as described below. The IPA coal supply agreements provide for aggregate sales of a minimum of 2.5 million tons per year and a maximum of 3.2 million tons in 2015 and a maximum of 3.0 million tons per year thereafter. Under each IPA coal supply agreement, in the event the customer does not take delivery of the annual volume or minimum annual volume of coal, as applicable, we may reschedule delivery of all or part of such shortfall tonnage or sell such shortfall tonnage to an alternate buyer, in which case the customer will compensate us for a specified percentage of administrative fees and for any deficiency in the per

ton price received. One agreement requires IPA to purchase 2.0 million tons of coal (Sufco mine quality) per year through December 31, 2024, with an option for the 2015 calendar year only for IPA to purchase an additional 0.2 million tons. The other agreement requires IPA to purchase a minimum of 500,000 tons and a maximum of 1.0 million tons of coal (Skyline mine quality) per year through December 31, 2024.

The coal supply agreements with IPA include price escalators, as well as provisions that allow us to pass through (by means of a price increase) certain increases in mining and transportation costs. The IPA coal supply agreements permit either the customer or us to terminate the agreement in the event changes in regulations affecting the coal industry increase the price of coal beyond a specified amount, subject to the non-terminating party's right to elect to continue the agreement by bearing such additional costs above the specified amount. In addition, the IPA coal supply agreements contain force majeure provisions allowing for the suspension of performance by either party for the duration of specified events to the extent made necessary by any such force majeure event. If a force majeure event prevents us from delivering or IPA from accepting more than 30% of each month's coal during any fiscal year, and if such force majeure event continues and cannot be eliminated for a six month period, then the party not claiming force majeure may terminate the applicable coal supply agreement.

Competition

The U.S. coal industry is highly competitive, both regionally and nationally. In the Western Bituminous region, we compete primarily with coal producers such as Peabody Energy Corporation, Arch Coal, Inc., UtahAmerican Energy, Inc., a subsidiary of Murray Energy Corporation, and Rhino Resource Partners LP. Outside of our region, we compete broadly with other U.S.-based producers of thermal coal and internationally with numerous global coal producers.

A number of factors beyond our control affect the markets in which we sell our coal. Continued demand for our coal and the prices obtained by us depend primarily on: the coal consumption patterns of the electricity industry in the United States and elsewhere around the world; the availability, location, cost of transportation and price of competing coal; and other electricity generation and fuel supply sources such as natural gas, oil, nuclear, hydroelectric and renewable energy. Coal consumption patterns are affected primarily by the demand for electricity, environmental and other governmental regulations and technological developments. The most important factors on which we compete are price, coal quality characteristics and reliability of supply.

Intellectual Property and Proprietary Rights

As part of our omnibus agreement, our sponsor has agreed to grant us a royalty-free license to use the name "Bowie" and related marks. Additionally, our sponsor has agreed to grant us a non-exclusive right to use all of our sponsor's current and future technology to operate our business.

Employees and Labor Relations

As of December 31, 2014, we employed 810 non-union workers. Of this total, 214 were salaried employees, including management and administrative personnel. Hourly employees include mine technicians, equipment operators, equipment maintenance engineers and loadout/plant operations maintenance workers. We emphasize safety across all operations.

We are highly focused on the safety of our coal operations and work diligently to meet or exceed all safety and environmental regulations required by state and federal laws. Safety performance at our mines continues to be significantly better than the national average. Our non-fatal days lost incidence rate was 16% of the industry average for the year ended December 31, 2014. Non-fatal days lost incidence rate is an industry standard used to describe occupational injuries that result in loss of one or more days from an employee's scheduled work. Our non-fatal days lost time incidence rate for all

operations for the year ended December 31, 2014 was 0.51 as compared to the national average of 3.16 for the same period, as reported by MSHA. This data is consistent with that of prior years and reflects a trend of excellence that we intend to maintain through our safety programs and policies. We also intend to continue to implement responsible, effective environmental practices throughout our operations and reclamation activities.

Legal Proceedings and Liabilities

From time to time, we are involved in lawsuits, claims or other proceedings with respect to matters such as personal injury, permitting, wrongful death, damage to property, environmental remediation, employment and contract disputes and other claims and actions arising in the ordinary course of business. We cannot estimate with certainty our ultimate legal and financial liability with respect to such pending litigation matters. However, we believe, based on our examination of such matters, that our ultimate liability will not have a material adverse effect on our financial position, results of operations or cash flows.

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THE COAL INDUSTRY

Except as otherwise indicated, the statistical information and industry and market data contained in this section is based on or derived from statistical information and industry and market data collated and prepared by Wood Mackenzie. The data is based on Wood Mackenzie's review of such statistical information and market data available at the time (including internal surveys and sources, independent financial information, independent external industry publications, reports or other publicly available information). Due to the incomplete nature of the statistical information and market data available, Wood Mackenzie has had to make some estimates where necessary when preparing the data. The data is subject to change and may differ from similar assessments obtained from other analysts of coal and energy markets. While Wood Mackenzie has taken reasonable care in the preparation of the data and believes it to be accurate and correct, data collection is subject to limited audit and validation procedures.

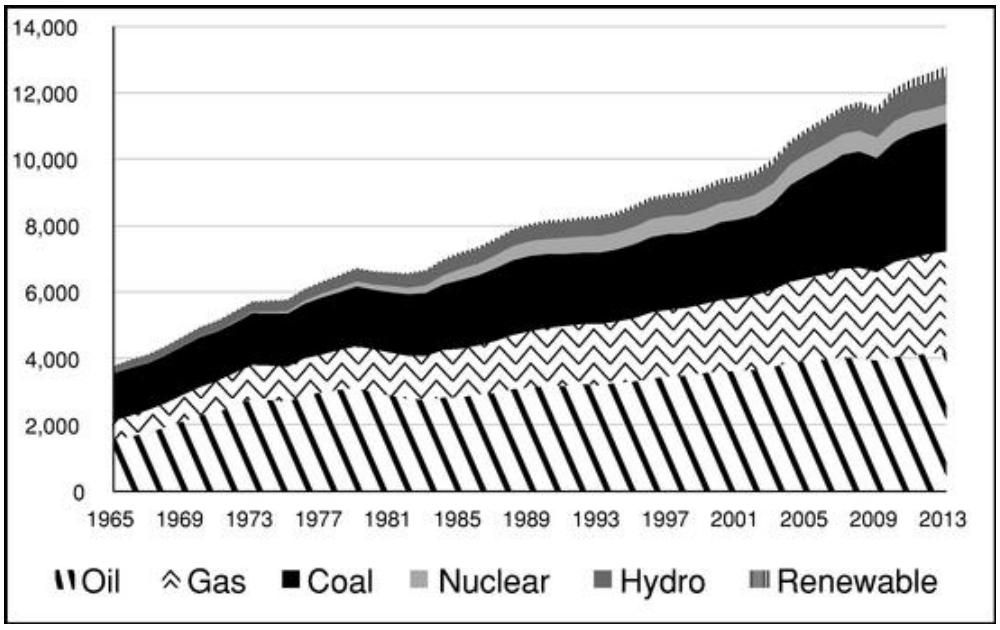
Introduction

Coal is an abundant and inexpensive natural resource and major contributor to the world's energy supply. Coal is primarily used as a fuel for electric power generation. According to the BP Statistical Review, global proven coal reserves totaled approximately 892 billion metric tons by the end of 2014 and represented approximately 30% of the world's primary energy consumption in 2014. According to Wood Mackenzie, the industrialization and development of China, India and the wider Asia Pacific region will ensure the long-term future of coal in the global energy mix.

The chart below demonstrates the importance of coal as global energy source over time according to the BP Statistical Review:

World Energy Consumption by Fuel Type

Million Tons of Oil Equivalents



Source: BP June 2015 Statistical Review.

Coal is generally categorized as either thermal coal or metallurgical coal and often ranked by heat content, with anthracite, bituminous, sub-bituminous and lignite coal representing the highest to lowest heat ranking, respectively. Thermal coal's main use is electricity generation by utilities and independent

power producers. Metallurgical coal is used by steel producers to create metallurgical coke for use in the steel making process.

The United States has the largest proven reserve base of coal in the world with approximately 237 billion metric tons, or approximately 27% of global coal proven reserves. According to the EIA, U.S. coal reserves would sustain 294 years of domestic supply based on 2012 consumption rates. Coal represents the largest domestic fossil fuel source, accounting for approximately 92% of domestic fossil energy reserves on a Btu basis, according to the National Mining Association. According to Wood Mackenzie, total U.S. electricity generation is expected to grow by 20.3% from 2014 to 2025. Despite recent reductions in coal-fired electrical demand, coal is expected to continue to account for the largest share of the electricity generation mix in the United States, representing an average 41.0% share of domestic electricity generation from 2014 to 2020.

Our industry segment. We produce high heat value, low sulfur thermal coal from our three underground mines in the Uinta Basin (Utah), part of the Western Bituminous region. In 2014, coal production in Utah increased by 7% over 2013 levels, according to MSHA data. Through 2020, Wood Mackenzie projects that total demand for Utah thermal coal will increase at a compound annual growth rate of 3.4% from 2013 levels compared to a projected compound annual decline of 1.9% for overall U.S. thermal coal demand. Our domestic customers are western utilities and industrial companies to which we sell coal mostly under long-term coal supply agreements. We also sell our coal internationally to a variety of intermediary and end-users in the power generation business. Our coal competes with all producers of thermal coal that supply coal to domestic or international consumers.

Coal Industry Trends

Global coal market. Coal will remain a fundamental component of the global energy system. Wood Mackenzie predicts coal will overtake oil as the world's most consumed fuel in 2018, primarily a consequence of power demand growth in developing markets such as China and India. This trend is expected to continue, with aggregate demand substantially exceeding that of oil by 2030. Non-hydro renewables are expected to grow rapidly during this period, averaging 6.1% annually, faster than any other energy source. However, this growth in renewables is from a low base, and by 2030, renewables are estimated to contribute only 2% of global energy supply.

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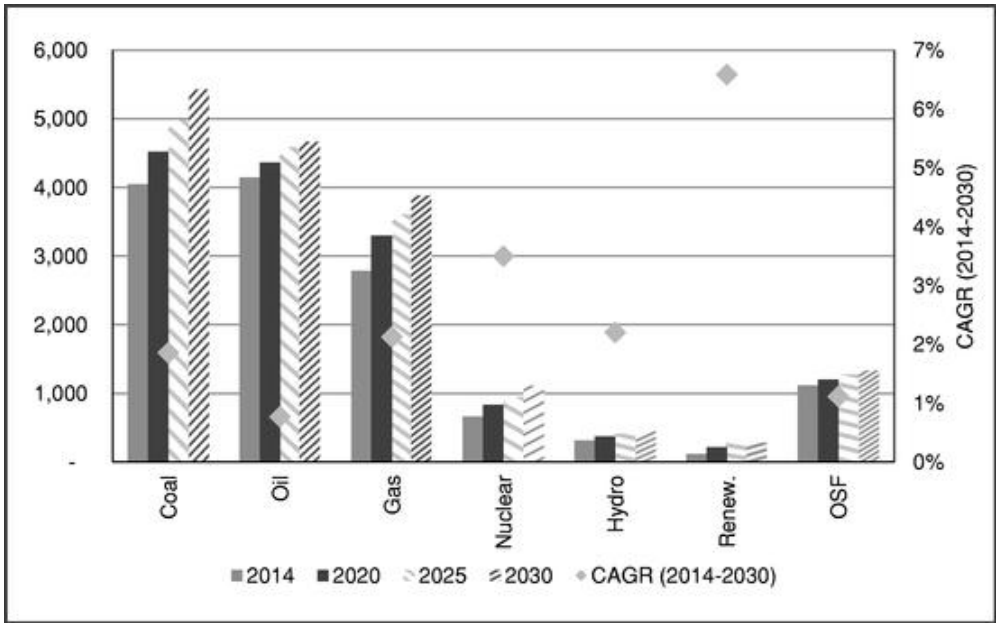
World Primary Energy Supply by Fuel 2014–2030

Million Tons of Oil Equivalent



Source: Wood Mackenzie, May 2015.

In 2014, global thermal coal demand was dominated by China. According to Wood Mackenzie, China's demand for thermal coal will account for 39% of global thermal coal demand growth between 2014 and 2030. By 2030, Chinese thermal coal demand is expected to represent 47% of world thermal coal demand. Coal's use as a power generation fuel will persist in the developed world, with coal accounting for an average of 20% of European and 30% of North American electricity generation from 2014 through 2030.

Seaborne Market

Demand growth for seaborne thermal coal. According to Wood Mackenzie, coal consumption in the seaborne thermal coal market grew at a compound annual growth rate of 7.7% from the period 2008–2014, increasing from approximately 614 million metric tons to approximately 959 million metric tons. Wood Mackenzie projects consumption of seaborne thermal coal to increase further to approximately 1.6 billion metric tons by 2035, a compound annual growth rate of 2.6% from 2014. Thermal coal demand has been growing in emerging economies, particularly in the Pacific Rim. According to Wood Mackenzie, countries outside of the developed economies of Europe, Japan and the United States imported 68% of the world's seaborne export thermal coal in 2014 and their share of the total seaborne thermal coal market is projected to increase to 80% by 2025.

Increased seaborne thermal coal import demand by China and India. China, which has traditionally been a net exporter of thermal coal, underwent a 175.8 million metric ton increase in imports from 2008 to 2014, a compound annual growth rate of 33%. Imports are expected to grow an additional 108% to 419.1 million metric tons by 2035, according to Wood Mackenzie. The chart below shows

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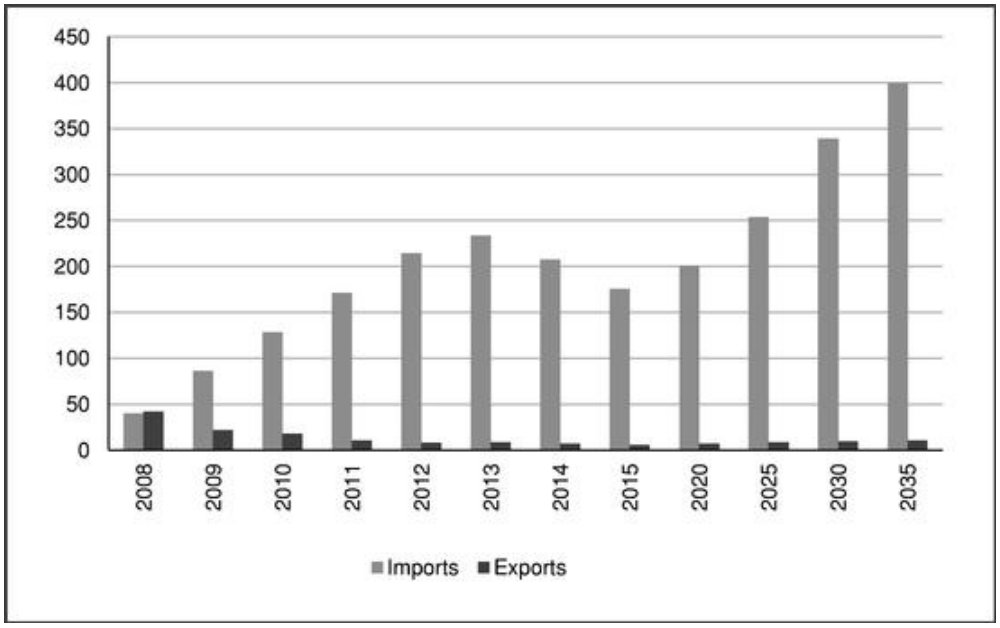
seaborne thermal coal import demand and seaborne thermal coal export supply for China from 2008 through 2035:

China Seaborne Thermal Coal Imports

Million metric tons



Source: Wood Mackenzie, May 2015.

The largest driver of the demand growth for seaborne coal in China over the next few decades will be the power sector. As shown in the chart below, from 2008–2035, coal demand from the power generation sector is expected to increase at a compound annual growth rate of 3.0%, doubling over that time period. Over the same period, coal demand from the cement sector will decline at a compound annual growth rate of –0.6%, and demand growth for all other sectors in China will grow at 1.0% per annum.

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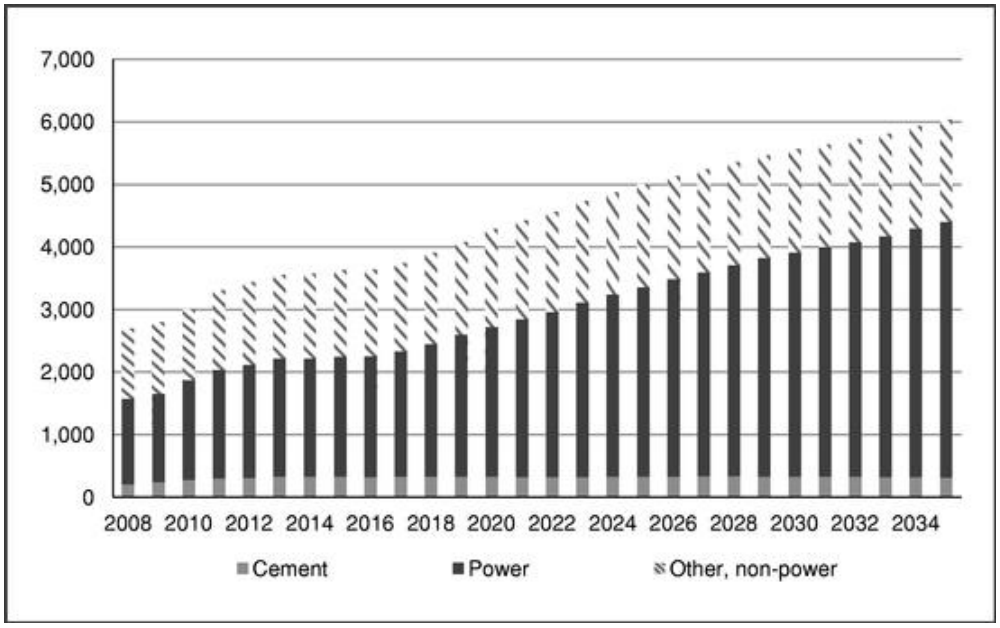
China Coal Consumption by Sector, 2008–2035

Million Metric Tons



Source: Wood Mackenzie, May 2015.

By 2035, seaborne thermal imports are expected to account for 8.6% of Chinese coal supply, compared with 6.0% in 2014. Per Wood Mackenzie, in 2014, the United States supplied 0.2 million metric tons of seaborne thermal coal to China, comprising less than 1% of its total thermal imports. According to Wood Mackenzie, by 2035, the United States will supply 39.3 million metric tons of seaborne thermal coal to China, comprising 9.4% of its total thermal imports.

Coal demand has also increased significantly in India, with seaborne imports rising from 28 million metric tons in 2008 to 157.5 million metric tons in 2014, a 33% compound annual growth rate. India's demand for imported thermal coal is expected to increase in both the near- and long-term, as the country has made clear its intent to increase coal-fired power generation as a share of its overall generation portfolio. Wood Mackenzie estimates that India had 182 gigawatts of coal-fired generation capacity in 2014 and expects this to increase by 176% to 449.8 gigawatts by 2035. Per Wood Mackenzie, between the period from 2014–2035, India's thermal coal imports are projected to increase by 213% to 404 million metric tons, and India's share of the seaborne thermal coal market is estimated to increase from 16% to 25% over the same period.

Countries that are large net exporters of thermal coal experience sporadic supply constraints. Occasionally, countries that export significant amounts of thermal coal have experienced supply constraints impacting the global seaborne thermal market balance. A variety of these countries have had their thermal coal exporting ability affected by various circumstances, including labor shortages, limited port capacity, limited rail transportation capacity, reliability and distance constraints, power generation shortages that limited coal processing capabilities, increased domestic consumption, unexpected weather patterns, increasingly stringent regulatory and environmental measures, political instability and diminishing coal qualities. Additionally, an intensifying operating cost environment and increased capital constraints, in conjunction with recent depressed thermal coal export prices, have forced shutdowns of some existing production and delays in new project development. We believe that

many countries with significant thermal coal import needs in the Pacific Rim will continue to diversify the sources from which they procure thermal coal.

Seaborne thermal coal markets will experience a period of over-supply in the near-term. Despite recent growth trends in seaborne coal markets and robust long-term fundamentals as forecast by Wood Mackenzie, a fluctuating global economy has led to lower near-term demand and lower global spot prices for seaborne thermal coal. According to globalCOAL, the Newcastle spot price of coal FOB Australia declined from $114.30 per metric ton at January 6, 2012, to $94.16 per metric ton at January 4, 2013, to $85.41 per metric ton at January 3, 2014, $61.94 per metric ton at January 2, 2015 and to $59.60 per metric ton at March 27, 2015. We believe that the current sustained low price environment will continue to cause high cost coal suppliers across the globe to shut down mine operations, which will result in lower global supply, and consequently, improved global pricing.

U.S. Coal Production

Coal remains a widely available and cost-competitive resource. Coal-fired power plants comprise a significant portion of the nation's power generation infrastructure. The EIA states that coal had a 47% average market share of electrical power generation in the United States over 2000–2013, predominantly due to its low cost and abundance. Depressed levels of electrical demand and low natural gas prices, in conjunction with other factors such as fuel freight costs and emission control costs, displaced some coal-fired generation in 2012. However, this trend began to reverse in 2013 as a result of rising natural gas prices and decline in the supply of coal. In its April Short Term Energy Outlook for 2015, the EIA projected the average cost of coal delivered to electric generating plants to be $2.34 on a dollars per million Btu basis versus $4.54 per million Btu for natural gas, implying an estimated price of natural gas that is 94% higher than coal for 2015. The below table details the average fuel prices per million Btu to electricity generators for a mix of fossil fuels:

Average Cost of Electricity Generation by Fossil Fuel
(Real 2013 Dollars per million Btu)

Electric Generation Type	2012	2013	2014	2015 (Est.)
Distillate Fuel Oil	$ 23.76	$ 24.04	$ 23.56	$ 17.19
Residual Fuel Oil	$ 20.52	$ 18.89	$ 20.32	$ 11.87
Natural Gas	$ 3.47	$ 4.40	$ 5.12	$ 4.54
Coal	$ 2.37	$ 2.34	$ 2.31	$ 2.34

Source: EIA, April 2015.

Recent trends in U.S. coal demand and production. Over the last ten years, the U.S. coal industry supplied an average of 966 million tons per year of coal production. The challenging economic conditions and relatively mild winter climate during 2012 in the United States decreased demand for electricity, and in turn, demand for thermal coal. In addition, U.S. natural gas prices reached record lows, creating an oversupply of U.S. thermal coal and high inventory stockpiles at utilities. These factors contributed to falling coal prices and led to a domestic supply and demand imbalance. Certain U.S. coal producers were forced to reduce workforces, idle or close high cost operations and defer capital expenditures across all U.S. coal basins. As a result, total U.S. coal production decreased by approximately 2.0% from 1,016 million tons in 2012 to 996 million tons in 2013, according to the EIA.

During 2013 and 2014, natural gas prices increased in the United States and provided the domestic coal market an opportunity to balance. Per the Henry Hub Index, natural gas spot prices increased

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136% from their 10-year monthly low of $2.00 per million Btu at the end of March 2012 to $3.14 per million Btu at the end of December 2014. However, natural gas prices fell again at the beginning of the 2015 due to oversupply and the decline in oil prices. The U.S. coal market is expected to face similar challenges this year to those faced in 2012. Wood Mackenzie projects that thermal coal production in the United States will decline by 88 million tons over last year, with 2015 U.S. thermal production totalling 832.1 million tons. Despite these conditions, the Utah coal market is expected to be somewhat insulated from the natural gas competition faced by the eastern markets. According to Wood Mackenzie, Utah coal demand is anticipated to increase by 2.6% this year over 2014 to 18.4 million tons.

Increasing demand for Utah coal. Wood Mackenzie projects total production of Utah coal to grow from 17.9 million tons in 2014 to 20.7 million tons in 2020, representing a compound annual growth rate of 2.4%. Demand for coal produced in Utah is expected to grow at a faster rate than overall U.S. coal demand. Utah coal generally has low sulfur content and demand for low sulfur coal has increased in the United States as utilities have had to comply with new environmental regulations such as the Clean Air Act. As many electric utilities have opted to forego retrofitting with scrubbers in the 25 years since the Clean Air Act passed, coal of the low-sulfur variety produced in the Western Bituminous region continues to have access to a market that cannot be supplied by high-sulfur coal from other regions. In addition, coal with low-sulfur content such as that produced in the Western Bituminous region is burned by utilities in both the Atlantic and Pacific seaborne markets.

Forecasted Utah Coal Demand
(Tons in millions)

End of Use Market	2013	2014	2015 (Est.)	2020 (Est.)	2025 (Est.)	2013–2025 Estimated Compound Annual Growth Rate
Mountain Region	12.6	11.8	10.7	12.2	11.3	(0.9)%
Export	1.7	4.0	4.4	5.0	4.7	8.8%
Industrial	1.3	1.3	1.3	1.3	1.3	0.0%
Other Domestic	0.8	0.8	2.0	2.2	0.4	(5.1)%
Total Utah Demand	16.4	17.9	18.4	20.7	17.8	0.7%

Source: Wood Mackenzie, May 2015.

Note: Due to rounding, numbers may not add up to total amounts and recalculations of percentages based upon the numbers disclosed may not produce the same results.

Impact of natural gas demand on thermal coal demand. Traditionally, coal has been the primary source of fuel for electricity generation in the United States, accounting for approximately one-half of the market, while natural gas supplied approximately 15% to 30% of the fuel used to generate electricity. Over the period from 2000 to 2007, the price of natural gas per the Henry Hub Index averaged $5.70 per million Btu; however, natural gas prices began to decrease substantially beginning in 2008 and reached a 10-year low at the end of March 2012 of $2.00 per million Btu.

As a result, from 2011 to 2012, the natural gas electricity generation market share increased from 24.7% to 30.3%, while coal-supplied generation fell from 42.3% to 37.4%, according to the EIA. In 2013, natural gas prices increased from 2012 levels to an average of $3.72 per million Btu and reached a high of $5.01 per million Btu at the end of January 2014. As a result of the increasing natural gas price environment, coal-fired generation regained some of its market share, attaining 39.1% in 2013.

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Given the low price environment for natural gas, it is expected that production of natural gas may decline at some point in the future. Baker Hughes has reported that the number of active natural gas drilling rigs dropped by 46%, from 811 rigs at the beginning of 2012 to 439 rigs at the beginning of 2013, and then fell an additional 25%, to 328 rigs as of October 24, 2014. We expect the lower rig count will lead to stabilized natural gas production.

Developments in U.S. regional coal markets. Historically, Central Appalachia has been the second largest coal basin by production (behind the Powder River Basin). Recently, production in Central Appalachia has declined and is expected to remain on this trajectory given its high production cost profile, its depleting reserves and recent regulations which have increased the difficulty in obtaining the necessary mining permits, particularly with regards to mountain-top mining, a method common across Central Appalachia. Given the difficult environment, thermal coal production in Central Appalachia has declined 69% from 219 million tons in 2002 to 67 million tons in 2014, per Wood Mackenzie. Thermal coal production in Central Appalachia is expected to continue to decline, with a 63% decrease expected from 2014–2035 and only 25.0 million tons of production expected in 2035. Diminished production from this region should be offset in part by increased production from other U.S. coal basins.

Powder River Basin experiencing higher coal transportation costs. Following the enactment of the Clean Air Act Amendments of 1990, many unscrubbed utilities began to comply with reduced sulfur dioxide emissions regulations by purchasing emission credits or switching to lower sulfur fuels. A result of these actions was increasing demand for low sulfur coal, such as that produced in the Western Bituminous region and the Powder River Basin. After a slight decline in production in 2012 and 2013 due to low natural gas prices, Western Bituminous coal production grew in 2014 to an estimated 85.8 million tons, a 2.4% increase from 2013 levels.

Another cost component that impacts Powder River Basin competitiveness is transportation. Most utilities consuming Powder River Basin coal negotiate long-term rail contracts with one of the two western railroads (Union Pacific and Burlington Northern Santa Fe) to control their transportation costs. Over the period from 1994–2004, reported average revenue per carload for these carriers increased 10.1%. Since the original transportation contracts began to expire in 2004, the reported average revenue per carload for these carriers has increased by 86.3% through December 31, 2013. The increased average cost of transportation for Powder River Basin coal is expected to result in higher delivered coal costs in the future.

The charts below compare the delivered cost of coal (including transportation cost) from our mines when delivered to Utah and to our key customers against the delivered cost of coal from the Powder River Basin and other regions.

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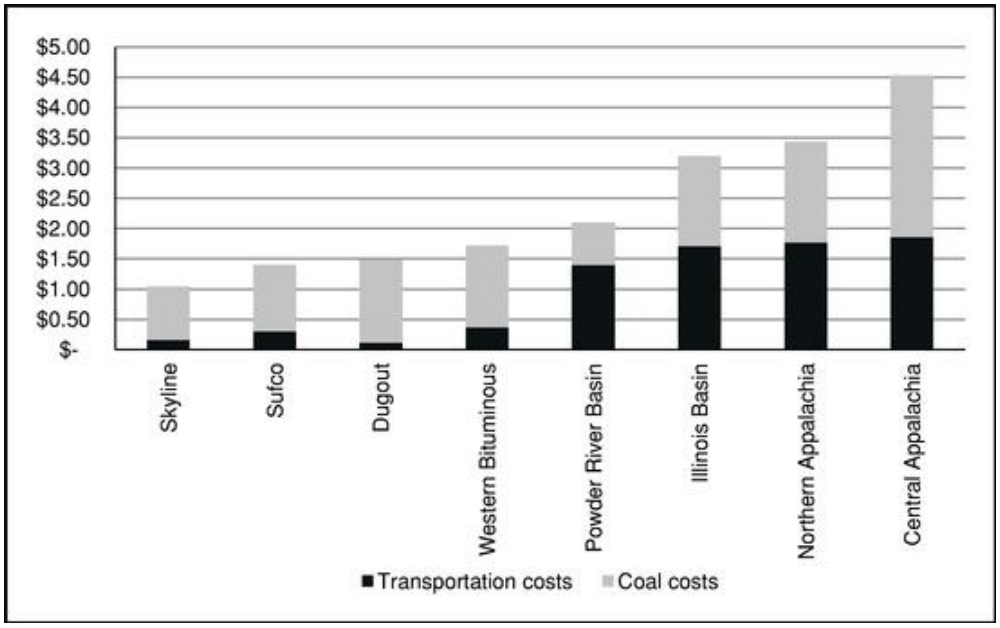
Transportation and Coal Cost Comparison: To Utah

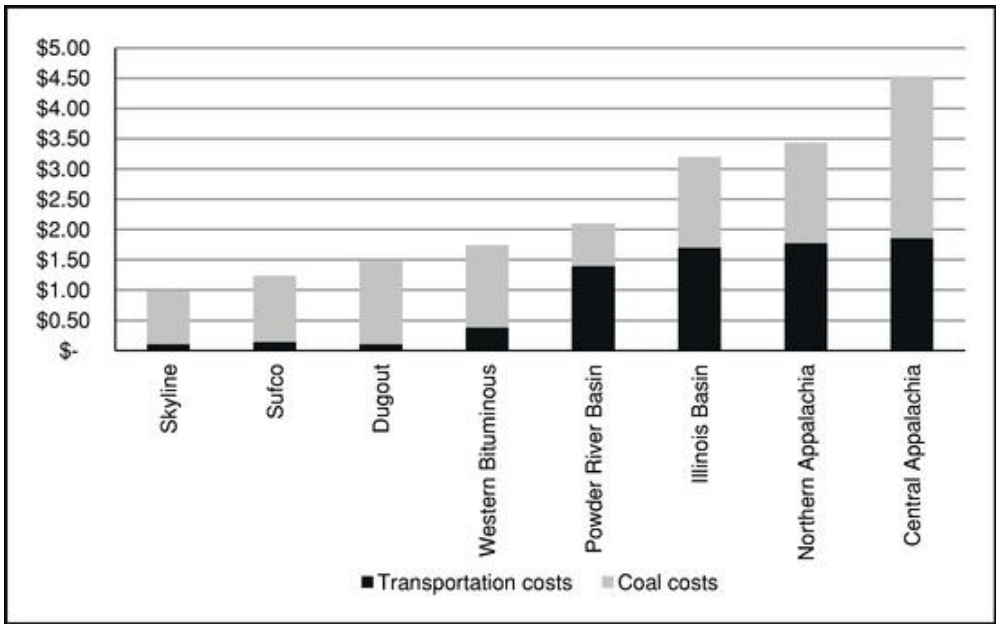
Delivered Coal Cost (US$/million Btu)



Source: Wood Mackenzie, May 2015.

Transportation and Coal Cost Comparison: To PacifiCorp

Delivered Coal Cost (US$/million Btu)



Source: Wood Mackenzie, May 2015.

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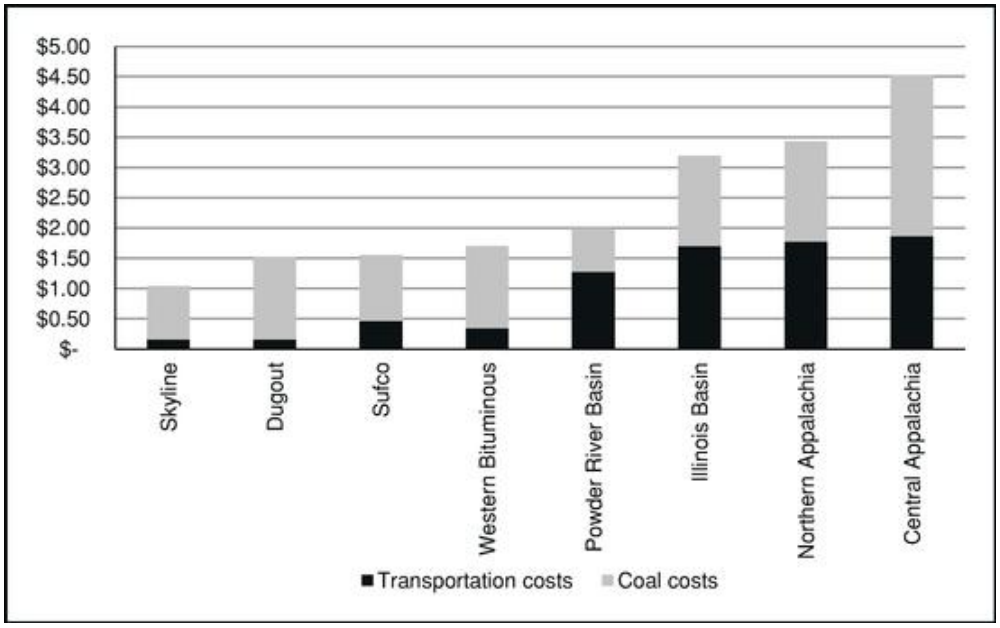
Transportation and Coal Cost Comparison: To Intermountain Power Agency

Delivered Coal Cost (US$/million Btu)



Source: Wood Mackenzie, May 2015.

Expected increases in international demand for U.S. coal exports over the long-term. Recently, U.S. coal exports have increased, supported by emerging economies across the globe and sustained growth in electric power generation and steel production capacity in Asia, most noticeably in China and India. Per Wood Mackenzie, U.S. coal exports rose from 59 million tons in 2009 to 102 million tons in 2014, a compound annual growth rate of 11.6%. While global coal prices have declined in recent years, and we expect U.S. coal export demand to be slightly weaker in the near term, we believe that potential supply shortfalls in the Pacific Rim will reverse this trend and lead to higher demand and improved pricing for U.S. thermal seaborne coal in the long term. We expect the Western Bituminous region to entrench itself as a key supplier of coal to the seaborne thermal market.

Coal demand will continue to be affected by increasingly restrictive environmental legislation. A series of more rigorous environmental requirements related to air emissions have limited the amount of carbon dioxide, nitrogen oxides, mercury, ozone and other emissions that can be produced by utilities across the United States. These regulations have been enacted by both federal and state regulatory agencies over the last few years. Additionally, environmental regulators are currently considering implementing further proposed limitations to GHG emissions. While past air quality legislation reducing sulfur emissions has resulted in an increase in demand for low sulfur coals such as those produced in the Western Bituminous region, we believe that additional air quality regulations will be adopted over time, which have the ability to adversely impact future demand for coal in the United States.

Coal Demand

Per the World Coal Association, world anthracite and bituminous coal consumption was estimated at 6.6 billion metric tons in 2013, approximately 1.1 billion metric tons of which were sold internationally, primarily in the seaborne coal market. The seaborne market consists of all coal shipped

between countries via ocean-going vessels apart from shipments between Canada and the United States via the Great Lakes.

Trends in thermal coal consumption are impacted by electricity demand, global power generation infrastructure, cost of transportation, governmental and environmental regulations, developments in technology, and the ease of procurement and cost advantage of other fuels including nuclear power, natural gas, and hydroelectric power. Seaborne metallurgical coal demand is influenced predominantly by global steel demand.

U.S. coal market. Thermal coal's predominant use is electricity generation, but it also supports industrial uses, and in the aggregate, thermal coal accounts for 98% of coal consumed in the United States. Metallurgical coal is predominantly consumed in the production of metallurgical coke used in steelmaking blast furnaces. Power generation from coal-fired power plants accounted for 38.7% of all power generated in the United States in 2014 compared to 27.4% from natural gas and 19.4% from nuclear power.

According to the EIA, between 1975 and 2010, thermal coal consumption in the United States more than doubled, reaching over 1.0 billion tons in 2010. As a result of the recent global economic downturn, the decreasing cost of natural gas and increasingly stringent regulatory and environmental constraints, domestic thermal coal consumption for electricity generation decreased to approximately 824 million tons in 2012, per the EIA. However, due primarily to recent increased gas prices, thermal coal consumption for electricity generation rose by 28 million tons in 2014 to 851 million tons, a 3% increase over 2012 levels.

The following table sets forth the consumption of coal in the United States by consuming sector as actual or forecasted, as applicable, by the EIA for the periods indicated:

U.S. Coal Consumption
(tons in millions)

	2012	2025 (Est.)	2035 (Est.)	2040 (Est.)
Electric Power	824	935	921	919
Other Industrial / Buildings	45	50	50	52
Steel Production	21	21	19	18
Total U.S. Coal Consumption	889	1,005	990	988

Source: EIA Annual Energy Outlook 2015, April 2015.

Note: Due to rounding, numbers may not add up to total amounts.

In the United States, the reliance on coal-fired generation is attributable to the abundance and low cost of coal. In 2012 and 2013, coal was the least expensive and most readily available fuel source in the United States. Coal was approximately 47% and 55% cheaper in 2013 and 2014, respectively, on a dollar per million Btu basis than natural gas, the next least expensive and readily available fuel source.

U.S. regulatory environment. Utilities are increasingly purchasing coal on a sulfur content basis, as opposed to a heat content basis (measured in dollars per million Btu), as the transition to sulfur mitigation systems, or scrubbers, continues to be required by more stringent environmental regulations such as the Clean Air Act. The Western Bituminous region is characterized by low cost, low sulfur coal, and is competitive with other coal basins across the nation due to its low cost, access to widespread

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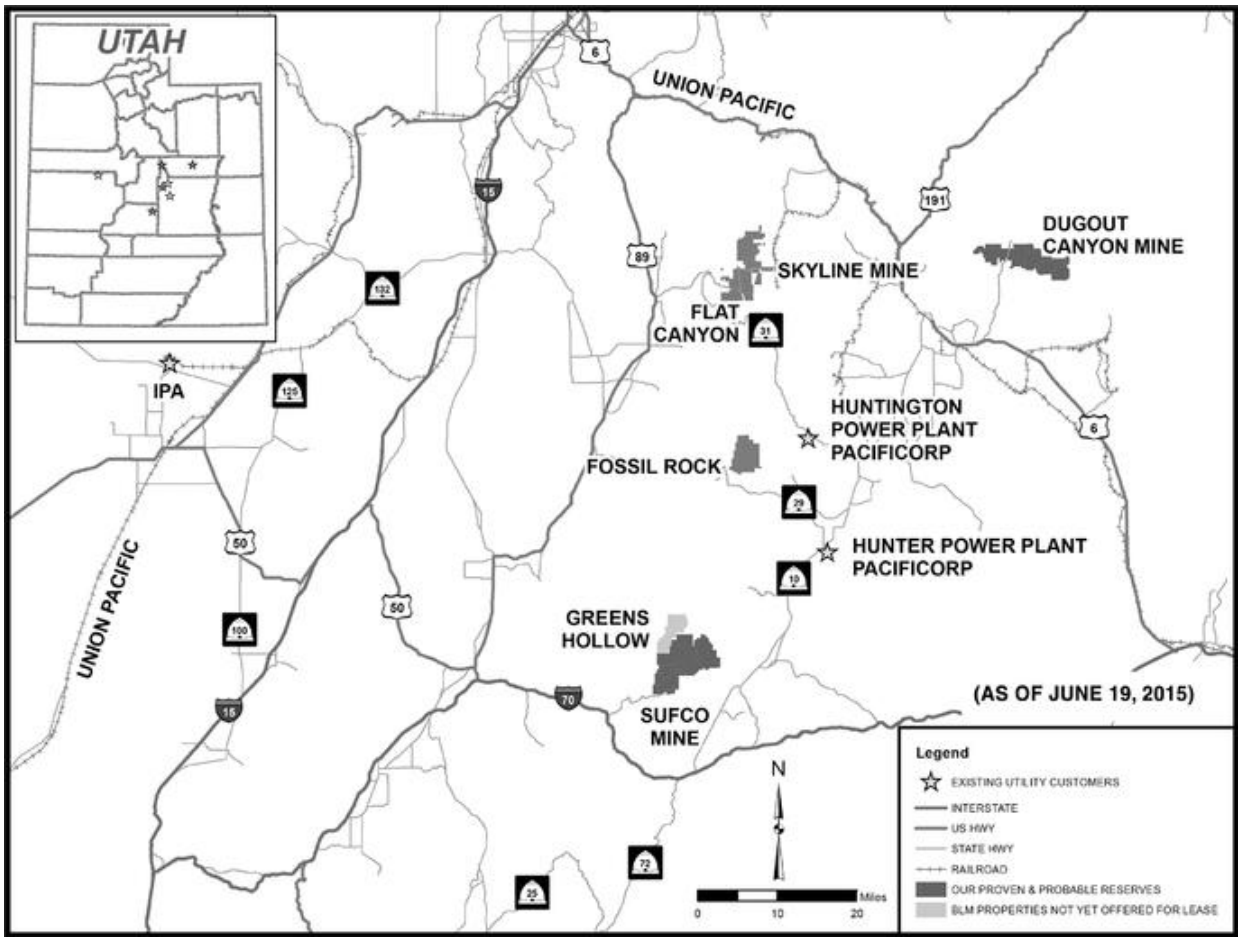
transportation outlets and its low sulfur content. The Clean Air Act Amendments of 1990 implemented restrictions on sulfur emissions by electric utilities, which caused most of these entities to comply with the new regulations by using lower sulfur coal or by purchasing sulfur emission credits. As the emission regulations continue to evolve, these compliance strategies will result in utilities increasingly turning to low sulfur coal products in an effort to comply with the new air emission limitation requirements in the most economic manner.

We believe that the Clean Air Act Amendments of 1990 will continue to drive demand for the low sulfur coal produced in regions such as Utah. According to Wood Mackenzie, total Utah coal demand including exports is expected to grow by 16%, from 17.9 million tons in 2014 to upwards of 20.7 million tons in 2020, in part due to the low sulfur content of coal from this region and transportation cost advantages over regions such as the Powder River Basin.

The following map shows certain coal-fired power plants, Western Bituminous mines and transportation infrastructure:



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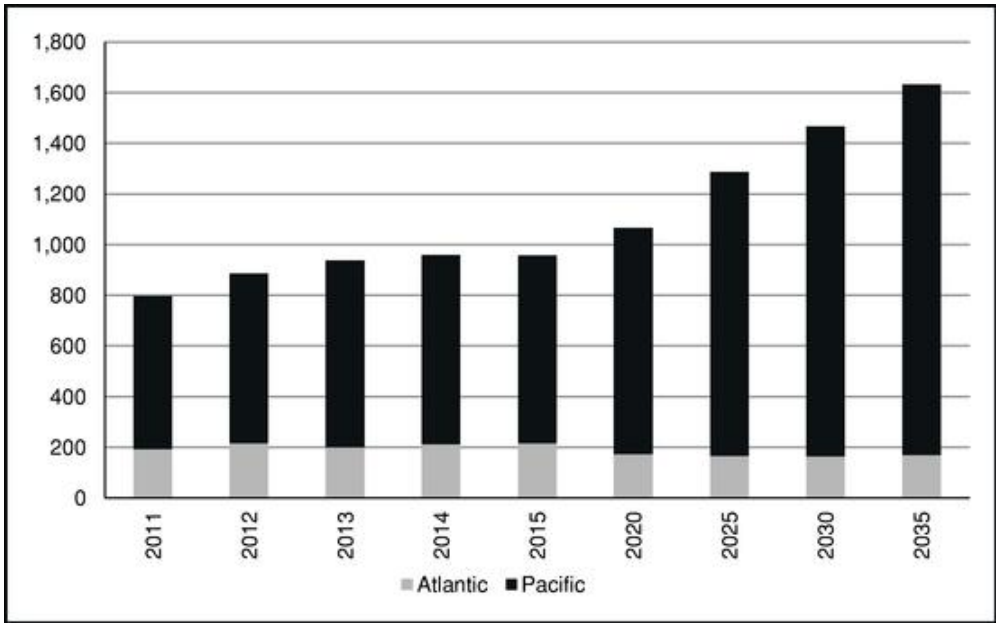
Seaborne coal market. Wood Mackenzie estimates that total seaborne thermal coal demand in 2014 was approximately 959 million metric tons. The seaborne coal markets for thermal coal consist of the Atlantic market and the Pacific market. The Atlantic market largely consists of countries in Europe, the Mediterranean region, North America, South America and Central America. Within the Atlantic market, the countries with the largest consumption of seaborne thermal coal are the United Kingdom, Germany, Turkey, Italy and France, based on 2013 figures per Wood Mackenzie. The Pacific market largely consists of countries in Asia and Oceania. The Pacific market's largest consuming countries for imported seaborne thermal coal are China, Japan, India, South Korea, Taiwan and Malaysia. The table below highlights the historical and forecasted growth in the seaborne thermal coal market, per Wood Mackenzie:

Global Thermal Seaborne Demand by Market

Million Metric Tons



Source: Wood Mackenzie, May 2015.

According to Wood Mackenzie, Atlantic market and Pacific market thermal coal demand was 262.0 million and 756.5 million metric tons, respectively, for 2014. The vast majority of significant coal-consuming countries in Asia are expected to experience substantial demand growth with China and India accounting for the largest portion of the increase. Wood Mackenzie projects total demand for seaborne thermal coal to increase from 958.6 million metric tons in 2014 to 1.3 billion metric tons by 2025.

Coal Production and Supply

China is the world's largest producer of coal with approximately 47% of the world's coal production, according to the 2015 BP Statistical Review. In 2014, China was followed by the United States (13%), Indonesia (7%), Australia (7%), India (6%), Russia (4%) and South Africa (4%).

U.S. coal production. According to the 2015 BP Statistical Review, the United States is not only the second largest coal producer in the world, but is also the largest holder of coal reserves in the world, with approximately 294 years of supply at 2012 production rates according to the EIA. U.S.

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thermal coal production was 920.5 million tons in 2014 according to Wood Mackenzie. While total annual domestic coal production has been relatively stable at approximately 1.0 billion tons since the mid-1990s, the production mix across basins has not remained constant over that period. Low-cost production from regions such as the Western Bituminous region, Powder River Basin and Illinois Basin has replaced high cost production from Central and Northern Appalachia. Wood Mackenzie forecasts that thermal coal production in the United States will decrease 12.9% from 2014 to 2025, and will primarily supply domestic coal-fired generating units together with increasing demand from the seaborne markets. The table below contains historical production information for a selection of U.S. coal producing regions for the periods, per Wood Mackenzie:

U.S. Historical Thermal Coal Production by Region

Region	1990	1995	2000	2005	2010	2013	2014	2000–2014 Increase (Decrease)
	(tons in millions)							
Utah	22.0	25.5	27.1	24.5	19.3	16.4	17.9	(9.2)
Western Bituminous (including Utah)	96.1	106.2	111.5	116.9	86.9	83.8	85.8	(25.7)
Powder River Basin	197.1	285.2	361.3	430.2	472.8	416.2	418.2	56.9
Central Appalachia	202.2	197.0	215.3	199.0	136.4	70.0	67.4	(147.9)
Northern Appalachia	158.9	132.9	136.1	135.2	115.0	110.6	117.9	(18.2)
Illinois Basin	141.2	108.9	88.1	95.0	106.7	132.2	137.2	49.1
Other	120.0	114.3	104.0	105.1	91.1	86.3	94.0	(10.0)
Total U.S. Coal Production	915.5	944.4	1,016.4	1,081.3	1,008.9	899.2	920.5	(95.9)

Source: Wood Mackenzie, May 2015.

Note: Due to rounding, numbers may not add up to total amounts.

Wood Mackenzie forecasts that the Utah area will experience the largest coal production growth rate among coal producing regions in the United States. We believe this is largely a result of increasingly stringent environmental and permitting regulations, declining geologic conditions, higher mining costs and greater transportation expenses impacting the Appalachian Basin. The following table sets forth forecasted production statistics for a selection of U.S. coal producing regions for the periods indicated based on Wood Mackenzie data:

U.S. Forecasted Thermal Coal Production by Region

Region	2015E	2016E	2020E	2015–2020 Forecasted CAGR
	(tons in millions)			
Utah(1)	18.4	18.4	20.7	2.4%
Western Bituminous (including Utah)(1)	77.0	78.2	82.0	1.3%
Powder River Basin(1)	410.0	399.6	398.9	(0.5)%
Central Appalachia(1)	52.2	33.9	23.6	(14.7)%
Northern Appalachia(1)	103.0	95.0	90.7	(2.5)%
Illinois Basin(1)	118.9	120.1	138.0	3.0%
Other	71.0	60.4	55.4	(4.9)%
Total U.S. Coal Production	832.1	787.1	788.5	(1.1)%

Source: Wood Mackenzie, May 2015.

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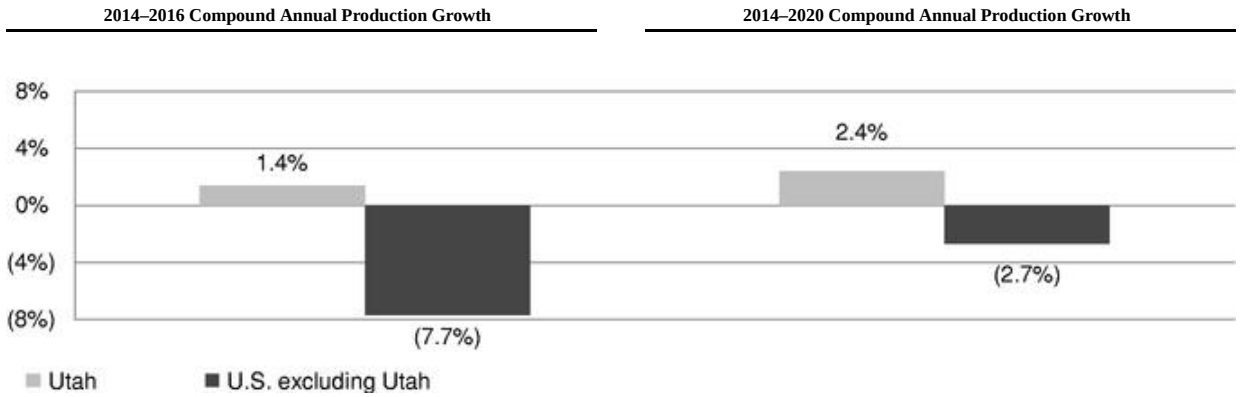
Note: Due to rounding, numbers may not add up to total amounts and recalculations of percentages based upon the numbers disclosed may not produce the same results.

(1) Regional data represents forecasted thermal coal production.

Wood Mackenzie estimates that Utah coal production will grow at a compound annual rate of 2.4%, from 17.9 million tons in 2014 to 20.7 million tons in 2020. Thermal coal production from other U.S. regions is estimated to decrease at a compound annual growth rate of 2.7% over the same period.

U.S. Forecasted Thermal Coal Production Growth



Source: Wood Mackenzie, May 2015.

Note: Due to rounding, recalculations of percentages based upon the numbers disclosed may not produce the same results.

Coal producing regions. Across the United States, more than one half of states produce coal, but domestic production is primarily attributable to three major coal producing regions: the Western, Interior and Appalachia regions. Within those three regions, the major producing centers are the Western Bituminous region and Powder River Basin in the Western region, the Illinois Basin in the Interior region and Northern Appalachia and Central Appalachia in Appalachia. Each region has unique coal types, characteristics and qualities for which it is known.

Western Bituminous Region. The Western Bituminous region is made up of parts of Utah, Colorado, New Mexico, Arizona and Wyoming and includes the Uinta Basin. The Western Bituminous region typically produces bituminous coal with sulfur content ranging from 0.8% to 1.8% and heat content ranging from 11,000 to 12,000 Btu per pound. We believe that recent abnormal weather patterns, combined with rail transportation constraints that can affect the Powder River Basin shipments, will create a sustained opportunity for Western Bituminous producers to provide low-cost, low sulfur coal across the United States.

Per Wood Mackenzie, coal production in the Western Bituminous region was 85.8 million tons in 2014. Wood Mackenzie forecasts that coal production in the Western Bituminous region will decrease by 3.8 million tons to 82.0 million tons in 2020, a decrease of 4.5%. However, Wood Mackenzie estimates that Utah coal production will grow by 15.6%, from 17.9 million tons in 2014 to 20.7 million tons in 2020.

Powder River Basin. The Powder River Basin is located in Wyoming and Montana. The Powder River Basin region typically produces sub-bituminous coal with sulfur content ranging from 0.2% to 0.8% and heat content ranging from 7,800 to 9,700 Btu per pound. After strong growth in production over the past 20 years, growth in domestic demand for Powder River Basin coal is expected to

moderate in the future due to transportation rate increases and growing operating costs as a result of higher strip ratios.

Per Wood Mackenzie, coal production in the Powder River Basin was 418.2 million tons for 2014. Wood Mackenzie forecasts that coal production in the Powder River Basin will decrease by 19.3 million to 398.9 million tons in 2020, an decrease of 4.6%.

Illinois Basin. The Illinois Basin spans western Kentucky, Illinois and Indiana. Reserves in this area are comprised of bituminous coal with typical heat content ranging from 9,700 to 12,800 Btu per pound and sulfur content ranging from 1.0% to 6.0%. Coal produced in the Illinois Basin is predominantly used for the generation of electricity, with minimal amounts used in industrial applications.

The Illinois Basin is divided into several regions which include northern Illinois, central Illinois, southern Illinois, West Kentucky and Indiana, each of which is known for distinct coal quality characteristics, transportation methods and mining logistics. Given its high sulfur content, coal from the Illinois Basin is typically suitable for electric power generation facilities that have installed pollution control devices, such as scrubbers, to reduce emissions.

According to Wood Mackenzie, coal production in the Illinois Basin was 137.2 million tons in 2014. Wood Mackenzie forecasts that coal production in the Illinois Basin will increase by 0.8 million to 138 million tons in 2020, a 0.6% increase.

Northern Appalachia. Northern Appalachia includes Ohio, Pennsylvania, Maryland and northern West Virginia. The region contains reserves of bituminous coal with heat content generally ranging from 11,100 to 13,900 Btu per pound and sulfur content typically ranging from 1.0% to 5.0%. Thermal coal produced in Northern Appalachia is predominantly marketed to electric utilities, industrial customers and the export market, while metallurgical coal production from the region is marketed to domestic and international steelmakers. Exports from Northern Appalachia predominantly serve customers in the Atlantic Basin.

According to Wood Mackenzie, total Northern Appalachia thermal coal production was 117.9 million tons in 2014. Wood Mackenzie forecasts that thermal production in Northern Appalachia will fall by 27.2 million to 90.7 million tons in 2020, a 23.1% decrease.

Central Appalachia. Central Appalachia includes eastern Kentucky, southern West Virginia, Virginia and northern Tennessee. The region contains reserves of bituminous coal with a heat content typically ranging from 11,500 to 14,200 Btu per pound and sulfur content typically ranging from 0.5% to 4.0%. Central Appalachian thermal coal is marketed primarily to electric utilities, industrial customers and the export market, while metallurgical coal production is marketed to domestic and international steelmakers. Reserve depletion, increasingly stringent regulatory standards and challenging geology in the region is expected to lead to significant decreases in production over the long-term.

According to Wood Mackenzie, total Central Appalachia thermal coal production was 67.4 million tons in 2014. Wood Mackenzie forecasts that thermal coal production in Central Appalachia will decline by 43.8 million to 23.6 million tons in 2020, a 65% decline.

U.S. coal exports. Historically, comparatively high transportation costs associated with moving coal from mine to Atlantic ports, coupled with a lack of available ports on the U.S. West Coast, has impeded the amount of coal that the United States could supply to the seaborne market, limiting its global competitiveness. Coal export volumes have fluctuated over the last decade, with a low of 48 million tons in 2004 and a high of 126 million tons in 2012. Of the 118 million tons of coal exported in 2013, 52 million tons were thermal coal with the balance being metallurgical coal. As demonstrated in the table below, over the period from 2004–2013, exported thermal and metallurgical coal from the United States increased 145%.

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U.S. Coal Exports
(tons in millions)

Product Type	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Thermal Coal	21	21	22	27	39	22	26	38	56	52
Metallurgical Coal	27	29	28	32	43	37	56	69	70	66
Total U.S. Coal Exports	48	50	50	59	82	59	82	107	126	118

Source: EIA, January 2014.

Seaborne coal supply. Seaborne thermal coal is supplied to both the Atlantic market and the Pacific market. Colombia, Russia, South Africa, the United States and Indonesia continue to be the principal suppliers to the Atlantic seaborne thermal coal market. Wood Mackenzie estimates that in 2014, the Atlantic market accounted for 262.0 million metric tons of thermal coal imports, just under 26% of the global thermal seaborne market. Indonesia, Australia, Columbia, South Africa and Russia are the principal suppliers of the Pacific seaborne thermal coal market. Wood Mackenzie estimates that in 2014, the Pacific market accounted for 756.5 million metric tons of thermal coal, just over 74% of the global thermal seaborne market.

One of the key trends in seaborne thermal coal is the growing demand in the Pacific Rim, with countries in the region unable to produce enough coal domestically to satisfy their power generation requirements. In countries that have historically been key suppliers to Asia, coal producers have recently been experiencing many challenges, among them infrastructure constraints, rising tax burdens, increasing government regulations, port capacity limitations, increasing domestic demand and restrictions on export quantities. While the Pacific market is currently experiencing a surplus of thermal coal, we believe that over the long-term, there will be an opportunity for low-cost U.S. producers to supply coal to the Pacific markets. The table below, per Wood Mackenzie data, highlights the projected supply of thermal coal exports:

Global Thermal Seaborne Coal Supply by Country
(metric tons in millions)

	Supply to Seaborne Market						
Country of Origin	2012 Actual	2013 Actual	2014 Actual	2015 Forecast	2025 Forecast	2030 Forecast	2012–2030 Compound Annual Growth Rate Forecast
Australia	173	186	205	210	294	423	5.1%
Colombia	81	80	77	82	132	132	2.8%
Russia	102	100	102	109	104	92	(0.5)%
South Africa	71	70	75	82	90	100	1.9%
Indonesia	358	396	380	400	517	523	2.1%
United States	53	52	39	33	94	134	5.3%
of which supply to Pacific market	16	18	11	15	48	50	6.5%
of which Western Bituminous	2	4	5	2	4	4	4.7%
Other Supply	61	73	59	41	55	62	0.1%
Total Supply	897	957	938	969	1,348	1,616	3.3%

Source: Wood Mackenzie, May 2015.

Note: Due to rounding, numbers may not add up to total amounts and recalculations of percentages based upon the numbers disclosed may not produce the same results.

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Transportation of coal. The coal industry in the United States relies upon the operation of a consistent, reliable transportation infrastructure to deliver its coal to its point of use both domestically and internationally. The primary methods of transportation for coal within the United States are railroads and barges, which account for approximately three-quarters of all coal shipments. When coal is only traveling a short distance from mine to point of use, trucks and conveyors are used as well.

Transportation has a large impact on the delivered price of coal at the point of use. The cost to transport coal from the mine to the customer can have a significant impact on the value of coal as it relates to the energy content that it delivers. Coal produced in the United States for domestic consumption is generally sold FOB at the mine or terminal and it is customary for the purchaser to take on the transportation costs as part of the price paid for the product. However, seaborne coal is generally sold FOB at the loading port. Depending upon the requirements of individual customers, producers may provide transportation and logistics services for the customer, often in turn for a higher negotiated price. The countries that import coal in both the Atlantic and Pacific seaborne markets have an established coal import terminal infrastructure.

Upon the enactment of the Clean Air Act Amendments of 1990, many utilities that did not have scrubbers chose to comply with reduced sulfur dioxide emissions mandates by purchasing emission credits and / or switching to lower sulfur fuels. As a result, Powder River Basin production increased from 197.1 million tons in 1990 to an estimated 418.2 million tons in 2014. In conjunction, some utilities that burn Powder River Basin coal decided to enter into long-term rail contracts with one of the two western U.S. railroads to minimize their spending on transportation costs. From 1994 to 2004, reported revenue per carload for these carriers was essentially unchanged, rising 10.1%. As many of the original long-term, fixed price contracts expired, unit rail charges increased significantly. From 2004 to December 31, 2013, average revenue per carload for these carriers increased by 86.3%.

On the U.S. West Coast, major export terminals for coal include the Port of Stockton, in Stockton, California; the Levin-Richmond Terminal and the Port of Long Beach, California. Multiple terminal development projects are ongoing, including the Morrow Pacific Project in Boardman, Oregon; Longview Terminal in Longview, Washington and the Gateway Pacific Terminal in Cherry Point, Washington. These projects have encountered significant resistance from local communities and environmental groups.

In the eastern United States, major export terminals for coal include the Port of New Orleans in New Orleans, Louisiana; Alabama State Docks in Mobile, Alabama; Port of Houston in Houston, Texas; Shipyard River Terminal in Charleston, South Carolina; Hampton Roads in Norfolk, Virginia; and Port of Baltimore in Baltimore, Maryland.

Coal Pricing

Prices for coal vary widely based on many factors, which include supply and demand balance, production and transportation costs, availability of alternate fuels, macroeconomic conditions, coal quality, governmental regulation and weather patterns. The two primary components of the delivered price of coal are the price of coal at the mine and the transportation costs required to get the coal to the point of use. Spot and forward prices for coal are generally based upon various published indices traditionally accepted by both buyers and sellers. Typically, coal prices for a given region are based on a benchmark price, and the price of coal is modified from this benchmark based on certain physical characteristics.

U.S. thermal coal market pricing. From 2002 through 2013, annual average thermal coal spot prices in Central Appalachia, Northern Appalachia, the Illinois Basin, the Powder River Basin and the Western Bituminous region increased in real 2014 terms by 69%, 61%, 40%, 32% and 60%, respectively. Over the course of this period, coal prices fluctuated along with short to medium-term supply/demand instabilities. Thermal coal prices increased substantially in 2008 predominantly due to

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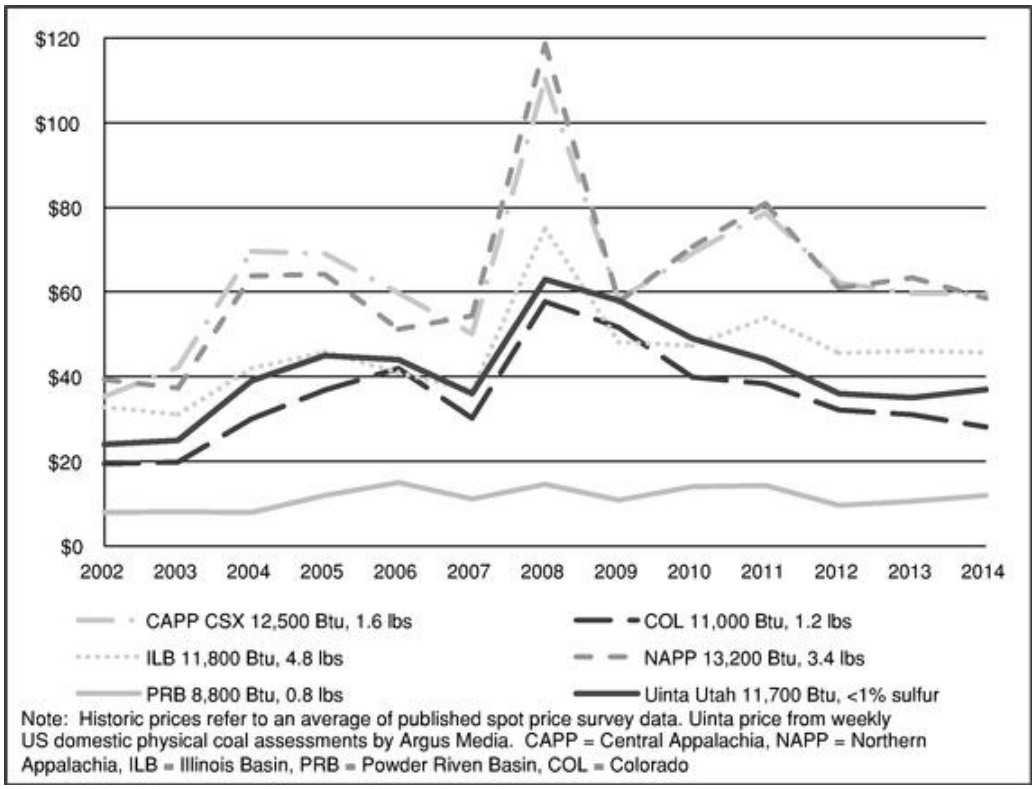
strong demand from both the domestic and export markets, paired with declines in inventory levels. This trend reversed in 2009 as a result of the U.S. recession and global economic downturn.

The following chart sets forth representative per ton thermal coal prices in various U.S. markets reported on an annualized basis for the period from January 1, 2002 to December 31, 2013, as reported by Wood Mackenzie. Historical prices for the Uinta Basin are reported by Argus Media and extend to December 31, 2014.

U.S. Coal Prices

Real 2015 US$ per ton



Source: Wood Mackenzie, May 2015 and Argus Media, March 2015.

Seaborne thermal coal market pricing. Thermal coal qualities sold on the international market vary widely, with premiums or discounts to benchmark prices based on a comparison of specific quality characteristics to the quality of the benchmark index. No single producer has sufficient market share to control pricing on the seaborne thermal coal market, thus all producers are price takers. Accordingly, the sales prices for seaborne thermal coal in a given market will typically fluctuate with changes in the balance of supply and demand, currency exchange rates, prices of transportation and other fuels and government regulations.

From the period 2008–2011, the seaborne thermal coal market experienced an upward trend in prices. Throughout this period, coal price fluctuations were based predominantly on short to medium-term supply and demand imbalances and inventory levels that were higher or lower than normal. The Pacific market seaborne coal prices rallied in 2010 and 2011 resulting from strong global demand from China and India which outweighed available supply. The following chart sets forth average historical coal prices from pricing surveys and forward projections (as of November 2014) for

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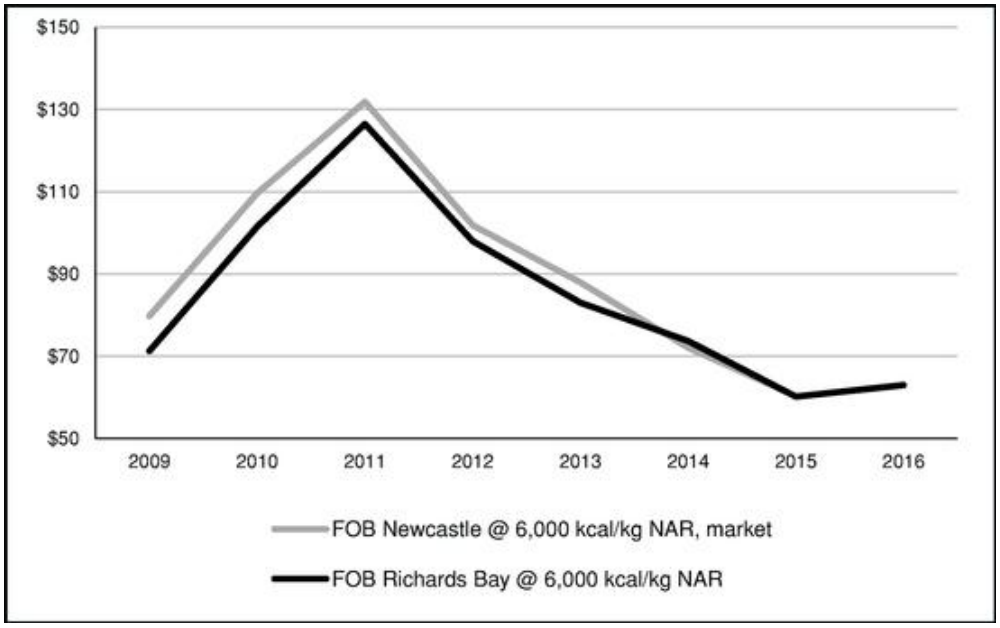
the FOB Newcastle thermal market price and FOB Richards Bay thermal market price, as reported and forecast by Wood Mackenzie.

Seaborne Thermal Coal Prices

Real 2015 US$ per metric ton



Source: globalCOAL and Wood Mackenzie, May 2015.

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ENVIRONMENTAL AND OTHER REGULATORY MATTERS

Our operations are subject to a variety of U.S. federal, state and local laws and regulations, such as those relating to employee health and safety; water discharges; air emissions; plant and wildlife protection; the restoration of mining properties; the storage, treatment and disposal of wastes; remediation of contaminants; surface subsidence from underground mining and the effects of mining on surface water and groundwater conditions. In addition, we may become subject to additional costs for benefits for current and retired coal miners.

We believe that we are in material compliance with all applicable environmental, health, safety and related requirements, including all required permits and approvals. From time to time, our mines have received citations or violations, but to date they have not resulted in material liabilities for us. However, there can be no assurance that violations will not occur in the future, that we will be able to always obtain, maintain or renew required permits or that changes in these requirements or their enforcement or the discovery of new conditions will not cause us to incur significant costs and liabilities in the future. Certain of our current and historical mining operations use or have used or store regulated materials which, if released into the environment, may require investigation and remediation. Under certain permits, we are required to monitor groundwater quality on and adjacent to our sites and to develop and implement plans to minimize and correct land subsidence, as well as impacts on waterways and wetlands, caused by our mining operations. While we cannot currently estimate our costs with any certainty, we do not expect these or other costs of compliance with existing environmental, health and safety requirements to be material during 2015. Moreover, under the terms of the omnibus agreement, our sponsor will indemnify us for certain environmental remediation costs. Please read "Certain Relationships and Related Party Transactions—Agreements with Affiliates in Connection with the Transactions—Omnibus Agreement." Major regulatory requirements are briefly described below.

Mine Safety and Health

In the United States, the Coal Mine Health and Safety Act of 1969, the Federal Mine Safety and Health Act of 1977 (the "1977 Act") and the Mine Improvement and New Emergency Response Act of 2006 impose stringent mine safety and health standards on all aspects of mining operations. In 1978, the MSHA was created to carry out the mandates of the 1977 Act and was granted enforcement authority. The MSHA is authorized to inspect all underground mining operations at least four times a year and issue citations with civil penalties for the violation of a mandatory health and safety standard. MSHA review and approval is required for a number of miner safety and welfare plans including ventilation, roof controls/bolting, safety training and ground control, refuse disposal and impoundments and respirable dust. For example, MSHA recently finalized a new rule limiting miners' exposure to respirable coal dust. The first phase of the rule went into effect of August 1, 2014, and requires, among other things, single shift sampling to determine noncompliance and corrective action to remedy any excessive levels of dust. The next phase of the rule takes effect February 1, 2016, and requires increased sampling frequency and the use of continuous personal dust monitors. Also, the State of Utah has its own programs for mine safety and health regulation and enforcement. These and other future mine safety rules could potentially result in or require significant expenditures, as well as additional safety training and planning, enhanced safety equipment, more frequent mine inspections, stricter enforcement practices and enhanced reporting requirements.

The costs of implementing these safety and health regulations at the federal and state level have been, and will continue to be, substantial. Moreover, in response to the April 2010 explosion at Massey Energy Company's Upper Big Branch Mine, we have seen an increase in enforcement scrutiny, including increased numbers of inspections, more inspection hours at mine sites, and increases in the number and severity of enforcement actions, including increased penalties for violations.

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Black Lung

Under the U.S. Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each coal mine operator must secure payment of federal black lung benefits to claimants who have been diagnosed with pneumoconiosis and are current and former employees. Companies must also contribute to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry prior to July 1, 1973 via an excise tax on production sold domestically of up to $1.10 per ton for deep-mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price. This tax is passed on to the purchaser under many of our coal supply agreements.

More recently, the Patient Protection and Affordable Care Act added an automatic survivor benefit paid upon the death of a miner with an awarded black lung claim and established a rebuttable presumption with regard to pneumoconiosis among miners with 15 or more years of coal mine employment that are totally disabled by a respiratory condition. These changes could make it more difficult for operators to defend against black lung claims.

U.S. Environmental Laws

We are subject to various U.S. federal, state and local environmental laws. Some of these laws, as described below, impose stringent requirements on our coal mining operations. U.S. federal and state regulations require regular monitoring of our mines and other facilities to ensure compliance. U.S. federal and state inspectors are required to inspect our mining facilities on a frequent schedule. Future laws, regulations or orders, as well as future interpretations or more rigorous enforcement of existing laws, regulations or orders, may require increases in capital and operating costs the extent of which we cannot predict.

Surface Mining Control and Reclamation Act

The SMCRA, which is administered by the OSM, establishes mining, environmental protection and reclamation standards for all aspects of surface mining as well as many aspects of deep mining. Mine operators must obtain SMCRA permits and permit renewals from the OSM or the applicable state agency. Where state regulatory agencies have adopted federal mining programs under SMCRA, the state becomes the regulatory authority. The Utah Division of Oil, Gas and Mining administers Utah's approved SMCRA program and therefore has achieved primary control of SMCRA enforcement in the State through federal authorization.

SMCRA permit provisions include a complex set of requirements which include: coal prospecting; mine plan development; topsoil removal, storage and replacement; selective handling of overburden materials; mine pit backfilling and grading; protection of the hydrologic balance; subsidence control for underground mines; surface drainage control; mine drainage and mine discharge control and treatment; restoration to the approximate original contour; and re-vegetation. The disposal of coal refuse is also permitted under the SMCRA.

The mining permit application process is initiated by collecting baseline data to adequately characterize the pre-mine environmental condition of the permit area. This work includes surveys of cultural and historical resources, soils, vegetation, wildlife, assessment of surface and ground water hydrology, climatology and wetlands. In conducting this work, we collect geologic data to define and model the soil and rock structures and coal that we will mine. We develop mining and reclamation plans by utilizing this geologic data and incorporating elements of the environmental data. The mining and reclamation plan incorporates the provisions of the SMCRA, state programs and other complementary environmental programs that affect coal mining. Also included in the permit application are documents defining ownership and agreements pertaining to coal, minerals, oil and natural gas, water rights, rights of

way and surface land, and documents required of the OSM's Applicant Violator System, including the mining and compliance history of officers, directors and principal owners of the entity.

Once a permit application is prepared and submitted to the regulatory agency, it goes through a completeness review and technical review. Public notice of the proposed permit is given that also provides for a comment period before a permit can be issued. Some SMCRA mine permits take over a year to prepare, depending on the size and complexity of the mine and may take months or years to be reviewed and issued. Regulatory authorities have considerable discretion in the timing of the permit issuance and the public and other agencies have rights to comment on and otherwise engage in the permitting process, including through intervention in the courts. Before a SMCRA permit is issued, a mine operator must submit a bond or otherwise secure the performance of reclamation obligations.

The Abandoned Mine Land Fund, which is part of the SMCRA, requires a fee on all coal produced. The proceeds are used to reclaim mine lands closed or abandoned prior to the SMCRA's adoption in 1977. Prior to October 1, 2012, the fee was $0.315 per ton on surface-mined coal and $0.135 per ton on deep-mined coal. Effective October 1, 2012, the fee on surface-mined coal was lowered to $0.28 per ton and the fee on deep-mined coal was lowered to $0.12 per ton.

The SMCRA stipulates compliance with many other major environmental statutes, including: the Clean Air Act; the Endangered Species Act; the CWA; RCRA and CERCLA.

Various federal and state laws, including the SMCRA, require us to obtain surety bonds or other forms of financial security to secure payment of certain long-term obligations, including mine closure or reclamation costs. As of December 31, 2014, we had outstanding surety bonds of $23.8 million related to these matters. Changes in these laws or regulations could require us to obtain additional surety bonds or other forms of financial security.

Clean Air Act

The Clean Air Act and comparable state laws that regulate air emissions affect coal mining operations both directly and indirectly. Direct impacts on coal mining operations may occur through Clean Air Act permitting requirements or emission control requirements relating to particulate matter, such as fugitive dust, including future regulation of fine particulate matter measuring 2.5 micrometers in diameter or smaller. The Clean Air Act indirectly affects coal mining operations by extensively regulating the air emissions of sulfur dioxide, nitrogen oxides, mercury and other compounds emitted by coal-fired electricity generating plants.

Clean Air Act requirements that may directly or indirectly affect our operations include the following:

Acid Rain

Title IV of the Clean Air Act required a two-phase reduction of sulfur dioxide emissions by electric utilities and applies to all coal-fired power plants generating greater than 25 Megawatts of power. The affected electricity generators have sought to meet these requirements by, among other compliance methods, switching to lower sulfur fuels, installing pollution control devices, reducing electricity generating levels or purchasing sulfur dioxide emission allowances. We cannot accurately predict the effect of these provisions of the Clean Air Act on us in future years. At this time, we believe that implementation has resulted in an upward pressure on the price of lower sulfur coals, such as ours, and could therefore have an adverse effect on demand for our coal.

NAAQS

The Clean Air Act requires the EPA to set standards, referred to as NAAQS, for certain pollutants. Areas that are not in compliance (referred to as "non-attainment areas") with these

standards must take steps to reduce emissions levels. The EPA has promulgated NAAQS for six common pollutants, including sulfur dioxide, nitrogen oxide, ozone, particulate matter with an aerodynamic diameter less than or equal to 10 microns ("PM10"), and for fine particulate matter with an aerodynamic diameter less than or equal to 2.5 microns ("PM2.5"). The EPA revised the PM2.5 NAAQS on December 14, 2012, making it more stringent. Pursuant to the 2012 revision, states were required to make recommendations on nonattainment designations for the new NAAQS in late 2013, and the EPA finalized its designations in December 2014, although the EPA deferred making designations for several areas due to data validity issues. Individual states must now identify the sources of PM2.5 emissions and develop emission reduction plans, which may be state-specific or regional in scope. Nonattainment areas must meet the revised standard no later than 2021. Future regulation and enforcement of the new PM2.5 standard will affect many power plants and coke plants, especially coal-fired power plants and all plants in non-attainment areas. Continuing non-compliance with NAAQS standards could prevent issuance of permits to facilities within the non-attainment areas. Meeting current or potentially more stringent NAAQS may require reductions of nitrogen oxide and sulfur dioxide emissions.

In November 2014, the EPA proposed a revision of the existing NAAQS for ozone. Specifically, the EPA proposed updating both its primary ozone standard and the secondary standard to 8-hour standards set within a range of 65 to 70 parts per billion (ppb). Significant additional emissions control expenditures will likely be required at coal-fired power plants and coke plants to meet the new standards, which are expected to be finalized in 2015. Nitrogen oxides, which are a by-product of coal combustion, can lead to the creation of ozone. Accordingly, emissions control requirements for new and expanded coal-fired power plants and industrial boilers and coke plants would continue to become more demanding in the years ahead. In March 2015, eleven states wrote a letter to the EPA asking the agency to drop its proposed revision and instead leave in place the current standard. More stringent NAAQS in the future for ozone could increase the costs of operating coal-fired power plants.

Cross-State Air Pollution Rule

The CSAPR, which was intended to replace the previously developed CAIR, requires states to reduce power plant emissions that contribute to ozone or fine particle pollution in other states. Under the CSAPR, emissions reductions were to have started January 1, 2012, for sulfur dioxide and annual nitrogen oxides reductions, and May 1, 2012, for ozone season nitrogen oxides reductions. Several states and other parties filed suits in the U.S. Court of Appeals for the D.C. Circuit in 2011 challenging the CSAPR. On August 21, 2012, the D.C. Circuit vacated the CSAPR and ordered the EPA to continue administering CAIR, pending the promulgation of a replacement rule. It is unclear what effect, if any, CAIR will have on our operations or results. On April 29, 2014, the U.S. Supreme Court found that the EPA was complying with statutory requirements when it issued CSAPR and reversed the D.C. Circuit's vacation of CSAPR. The case was remanded to the D.C. Circuit for further proceedings consistent with the Court's opinion. On June 26, 2014, the United States filed a motion asking the D.C. Circuit to lift its stay of CSAPR. On October 23, 2014, the court granted the EPA's request to lift the stay, and on November 21, 2014, the EPA issued an interim final rule reconciling the CSAPR rule with the court's order, which calls for Phase 1 implementation in 2015 and Phase 2 implementation in 2017. However, other legal challenges to CSAPR remain in the D.C. Circuit litigation. Arguments were heard in the remanded D.C. Circuit litigation in February 2015, and a ruling is expected later this year. Because U.S. utilities have continued to take steps to comply with CAIR, which requires similar power plant emissions reductions, and because utilities are preparing to comply with the Mercury and Air Toxics Standards regulations which require overlapping power plant emissions reductions, the practical impact of CSAPR is expected to be limited.

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Mercury and Air Toxic Standards

On December 16, 2011, the EPA issued the MATS to reduce emissions of toxic air pollutants, including mercury, other metals and acid gases, from new and existing coal and oil fired power plants. Under the final rule, existing power plants will have up to four years to comply with the MATS by installing or upgrading pollution controls, fuel switching, or using existing emissions controls as necessary to meet the compliance deadline. The D.C. Circuit upheld various portions of the rulemaking in two separate decisions issued in March and April 2014, respectively. In November 2014, the U.S. Supreme Court granted certiorari to review the D.C. Circuit decision. The Supreme Court heard oral arguments in the case in March 2015. The MATS requirements could significantly increase our customers' costs and cause them to reduce their demand for coal, which may materially impact our results or operations.

Some utilities have been moving forward with installation of equipment necessary to comply with MATS, and the EPA and states have been granting additional time beyond the 2015 deadline (but no more than one extra year) for facilities that need more time to upgrade and complete those installations. The rule could result in the retirement of certain older coal plants.

Greenhouse Gases

Concerns about GHG, including carbon dioxide, emitted from burning coal at electric generation plants has led to efforts at all levels of government to reduce their emissions, which could require utilities to burn less or eliminate coal in the production of electricity. Congress has considered federal legislation to reduce GHG emissions which, among other things, could establish a cap and trade system for GHG, including carbon dioxide emitted by coal burning power plants, and requirements for electric utilities to increase their use of renewable energy such as solar and wind power. Also, the EPA has taken several recent actions under the Clean Air Act to regulate GHG emissions. These include, among others, the EPA's finding of "endangerment" to public health and welfare from GHG and its issuance in 2009 of the Final Mandatory Reporting of Greenhouse Gases Rule, which requires large sources, including coal-fired power plants, to monitor and report GHG emissions to the EPA annually starting in 2011. The EPA also recently proposed new source performance standards for GHG for new coal and oil-fired power plants, which could require partial carbon capture and sequestration to comply. On June 2, 2014, the EPA further proposed new regulations limiting carbon dioxide emissions from existing power generation facilities. Under this proposal, nationwide carbon dioxide emissions would be reduced by 30% from 2005 levels by 2030 with a flexible interim goal. The final rule is expected to be issued by mid-summer 2015 and the emission reductions are scheduled to commence in 2020. A legal challenge to the proposed rulemaking was already filed by a coal company, and twelve states joined the suit. However, the D.C. Circuit Court of Appeals denied the petitions for review, holding that the court did not have authority to review agency rules that are not yet final. Although this suit was unsuccessful, similar judicial challenges are likely to be filed in the future once these regulations are finalized. We expect that the EPA's proposed regulations for both new and existing power plants, if promulgated along the lines proposed, would negatively affect the viability of coal-fired power generation, which could ultimately reduce demand for our coal. Although the EPA's actions are subject to procedural delays and legal challenges, and efforts are underway in Congress to limit or remove the EPA's authority to regulate GHG emissions, they will proceed as proposed unless revised by the EPA or altered by the courts or Congress.

The U.S. Supreme Court, in a decision issued on June 23, 2014, addressed whether the EPA's regulation of GHG emissions from new motor vehicles properly triggered GHG permitting requirements for stationary sources under the Clean Air Act. Through its Prevention of Significant Deterioration ("PSD") and Title V Greenhouse Gas Tailoring Rule, the EPA sought to require large industrial facilities, including coal-fired power plants, to obtain permits to emit, and to use best available control technology to curb, GHG emissions. The decision reversed, in part, and affirmed, in part, a 2012 D.C. Circuit

decision that upheld the EPA's GHG-related regulations. Specifically, the court held that the EPA exceeded its statutory authority when it interpreted the Clean Air Act to require Prevention of Significant Deterioration and Title V permitting for stationary sources based on their potential GHG emissions. However, the Court also held that the EPA's determination that a source already subject to the PSD program due to its emission of conventional pollutants may be required to limit its GHG emissions by employing the "best available control technology" was permissible.

Non-government organizations have also petitioned the EPA to regulate coal mines as stationary sources under the Clean Air Act. On May 13, 2014, the D.C. Circuit in *WildEarth Guardians v. United States Environmental Protection Agency* upheld the EPA's denial of one such petition. On July 18, 2014, the D.C. Circuit denied a petition to rehear that case en banc.

Regional Emissions Trading

Nine Northeast and Mid-Atlantic states have cooperatively developed a regional cap and trade program, the Regional Greenhouse Gas Initiative, intended to reduce carbon dioxide emissions from power plants in the region. There can be no assurance at this time that this, or similar state or regional carbon dioxide cap and trade programs, in the states where our customers operate, will not adversely affect the future market for coal in the region.

Regional Haze

The EPA has initiated a regional haze program designed to protect and to improve visibility at and around national parks, national wilderness areas and international parks. This program restricts the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas. Moreover, this program may require certain existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxides, volatile organic chemicals and particulate matter. In March 2015, the Utah Air Quality Board released a revised proposed State Implementation Plan to address regional haze. In the meantime, a non-governmental organization has filed a lawsuit in federal court seeking, among other relief, an injunction compelling EPA to promulgate a Federal Implementation Plan to address regional haze in Utah. As of June 5, 2015, this litigation has been stayed for 60 days pending settlement negotiations. These limitations could adversely affect the future market for coal.

New Source Review/PSD

A number of pending regulatory changes and court actions are affecting the scope of the EPA's new source review and PSD programs, which under certain circumstances require existing coal-fueled power plants to install the more stringent air emissions control equipment required of new plants. The new source review and PSD programs are continually revised and such revisions may impact demand for coal nationally, but we are unable to predict the magnitude of the impact.

Resource Conservation and Recovery Act

The RCRA affects coal mining operations by establishing requirements for the treatment, storage, and disposal of hazardous wastes. Certain coal mine wastes, such as overburden and coal cleaning wastes, are exempted from hazardous waste management.

Subtitle C of the RCRA exempted fossil fuel combustion wastes from hazardous waste regulation until the EPA completed a report to Congress and made a determination on whether the wastes should be regulated as hazardous. In 2000, the EPA concluded that coal combustion wastes do not warrant regulation as hazardous under the RCRA. Following a large spill of coal ash waste at a coal burning power plant in Tennessee in June 2010, the EPA proposed two alternative sets of regulations governing the management and storage of coal ash: one would regulate coal ash and related ash impoundments at

coal-fired power plants under federal regulations governing hazardous solid waste under Subtitle C of the RCRA and the other would regulate coal ash as a non-hazardous solid waste under Subtitle D. In December 2014, the EPA finalized regulations that address the management of coal ash as a non-hazardous solid waste under Subtitle D. The rules impose engineering, structural and siting standards on surface impoundments and landfills that hold coal combustion wastes and mandate regular inspections. The rule also requires fugitive dust controls and imposes various monitoring, cleanup, and closure requirements.

In addition, environmental groups filed a notice of intent to sue the EPA for failing to update effluent limitation guidelines under the CWA for coal-fired power plants to limit discharges of toxic metals from handling of coal combustion waste. In April 2013, the EPA released its proposed revised effluent limitation guidelines to address toxic pollutants discharged from power plants, including discharges from coal ash ponds. Pursuant to a consent decree, the EPA is required to sign a final action on the rule by September 30, 2015. If the EPA adopts new CWA requirements, compliance obligations for handling, transporting, storing and disposing of the material would likely increase. Potential changes to all of these rules could make coal burning more expensive or less attractive for electric utilities.

Most state hazardous waste laws exempt coal combustion waste and instead treat it as either a solid waste or a special waste. These laws may also be revised. Any costs associated with handling or disposal of coal ash as hazardous wastes would increase our customers' operating costs and potentially reduce their ability to purchase coal. In addition, potential liability for contamination caused by the past or future use, storage or disposal of ash could substantially increase.

Clean Water Act of 1972

The CWA established in-stream water quality standards and treatment standards for waste water discharge through the NPDES. Regular monitoring, reporting requirements and performance standards are requirements of NPDES permits that govern the discharge of pollutants, including selenium, sulfate and specific conductance, into water. Discharges that exceed the limits specified under NPDES permits can lead to the imposition of penalties, and persistent non-compliance could lead to significant penalties, compliance costs and delays in coal production. In addition, the imposition of future restrictions on the discharge of certain pollutants into "waters of the United States" could increase the difficulty of obtaining and complying with NPDES permits, which could impose additional time and cost burdens on our operations. Moreover, in May 2015, the EPA released a finalized rule that sets forth changes to its definition of "waters of the United States." Although EPA has stated that the rule does not create any new permitting requirements and maintains all previous exemptions and exclusions, we are currently evaluating the effects, if any, the finalized rule may have on our operations or permitting obligations. Any expansion to CWA jurisdiction could impose additional permitting obligations on our operations, which may adversely impact our coal production or results of operations.

TMDL regulations establish a process by which states may designate stream segments as "impaired" (not meeting present water quality standards). Industrial dischargers, including coal mines and plants, will be required to meet new TMDL effluent standards for these stream segments. The adoption of new TMDL regulations in receiving streams could hamper or delay the issuance of discharge and Section 404 permits, and if issued, could require new effluent limitations for our coal mines and could require more costly water treatment, which could adversely affect our coal production or results of operations. States are also adopting anti-degradation regulations in which a state designates certain water bodies or streams as "high quality." These regulations would prohibit the diminution of water quality in these streams. Waters discharged from coal mines to high quality streams will be required to meet or exceed new "high quality" standards. The designation of high quality streams at or in the vicinity of our coal mines could require more costly water treatment and could adversely affect our coal production or results of operations.

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In the case of both the TMDL and anti-degradation review, the limits in our NPDES discharge permits could become more stringent, thereby potentially increasing our treatment costs or making it more difficult to obtain new permits. Other requirements may result in obligations to treat discharges from coal mining properties for non-traditional pollutants, such as chlorides, selenium and dissolved solids and/or require us to take measures intended to protect streams, wetlands, other regulated water sources and associated riparian lands from mining impacts. Individually and collectively, these requirements may cause us to incur significant additional costs that could adversely affect our operating results, financial condition and cash flows.

On May 19, 2014, the EPA issued a new final rule pursuant to Section 316(b) of the CWA that affects the cooling water intake structures at power plants in order to reduce fish impingement and entrainment. The rule is expected to affect over 500 power plants. These requirements could increase our customers' costs and cause them to reduce their demand for coal, which may materially impact our results or operations.

CERCLA and Similar State Superfund Statutes

CERCLA and similar state laws affect coal mining by creating liability for the investigation and remediation of releases of regulated materials into the environment and for damages to natural resources. Under these laws, joint and several liability may be imposed on waste generators, current and former site owners or operators and others regardless of fault, for all related site investigation and remediation costs. Although the EPA excludes most wastes generated by coal mining and processing operations from the hazardous waste laws, such wastes can, in certain circumstances, constitute hazardous substances for the purposes of CERCLA. In addition, the disposal, release or spilling of some products used by coal companies in operations, such as chemicals, could trigger the liability provisions of the statute. Thus, coal mines that we currently own or have previously owned or operated, and sites to which we sent waste materials, may be subject to liability under CERCLA and similar state laws.

National Environmental Policy Act

Substantially all of our planned activities and operations include acreage located on federal land and, thus, require one or more governmental approvals that may trigger the requirements of NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions such as issuing an approval, that have the potential to significantly impact the environment. In the course of such evaluations, an agency will typically prepare an environmental assessment to assess the potential direct, indirect and cumulative impacts of a proposed project. Where the activities in question have significant impacts to the environment, the agency, in this instance, must prepare an environmental impact statement, or EIS. Compliance with NEPA can be time-consuming and may result in the imposition of mitigation measures that could affect the amount of coal that we are able to produce from mines on federal lands, and may require public comment.

Whether agencies have complied with NEPA is subject to protest, appeal or litigation, which can delay or halt projects. For example, in June 2014, the U.S. District Court for the District of Colorado, in *High Country Conservation Advocates v. United States Forest Service*, found that the U.S. Forest Service and the BLM failed to comply with the requirements of NEPA when ruling on various coal mine-related matters, including various lease modifications. The court found that two separate EIS reports prepared by the agencies were insufficient because they failed to include certain data and analysis relating to the impacts of carbon emissions. Accordingly, in September 2014, the court vacated the agencies' approvals, including those related to the lease modifications. This decision adds to the uncertainty surrounding the nature and extent of disclosure required by NEPA for climate change impacts associated with governmental actions. Recently, the Council on Environmental Quality published an updated Draft Guidance for federal agencies on "when and how" to consider and discuss the effects of GHG emissions in any analysis undertaken pursuant to NEPA, but it remains to be seen

whether this guidance will provide meaningful certainty about the nature of the disclosures required under NEPA for climate change impacts associated with governmental actions. In another recent case, *WildEarth Guardians v. United States Office of Surface Mining, Reclamation and Enforcement*, the United States District Court for the District of Colorado identified several deficiencies in the NEPA compliance processes relating to approvals of two separate mining plan modifications for Colorado coal mines that had been issued in 2007 and 2009, respectively. The court gave the Office of Surface Mining 120 days to address these deficiencies before the previously-approved mining plans would be vacated. This decision demonstrates courts' willingness to assess NEPA compliance even where relevant approvals have been granted long ago and mining operations are underway.

Recently, non-governmental organizations have filed objections with the BLM and U.S. Forest Service regarding the BLM's decision to offer the Greens Hollow tract for lease. These objections allege that the supplemental environmental impact statement prepared in connection with the issuance of the Greens Hollow lease fails to comply with NEPA for many reasons, including the failure to adequately address impacts associated with GHG emissions. Further, the leasing action related to the Flat Canyon tract by the BLM could also be challenged in the Department of Interior's Board of Land Appeals or in federal district court. The May 15, 2015 Notice of Lease Sale of the Flat Canyon tract prompted letters by several non-governmental organizations objecting to the lease sale on, among other things, environmental grounds. Although we do not expect any delays in our development plans or operations because of the NEPA review process, NEPA reviews may extend the time and/or increase the costs for obtaining necessary governmental approvals.

Endangered Species Act

Protection of threatened, endangered and other special status species may have the effect of prohibiting or delaying us from obtaining mining permits. Based on the species that have been identified to date and the current application of applicable laws and regulations, however, we do not believe there are any species protected under the Endangered Species Act that would materially adversely affect our ability to mine coal from our properties in accordance with current mining plans. Should more stringent protective measures be applied to threatened, endangered or other special status species or to their critical habitat, then we could experience increased operating costs or difficulty in obtaining future mining permits.

The U.S. Fish and Wildlife Service ("USFWS") is currently subject to an agreement that requires it to determine by September 2015 whether the greater sage-grouse will be listed as a threatened species. Pursuant to this agreement, the USFWS has initiated its formal status review of the greater sage-grouse under the Endangered Species Act. However, in December 2014, a coalition of mining and ranching groups filed a lawsuit in federal court challenging earlier settlements between USFWS and various non-governmental organizations pursuant to which USFWS must make listing determinations for several species, including the greater sage-grouse, by various dates certain. In March 2015, several counties and industry associations filed challenges against the BLM, USFWS, and U.S. Geological Survey pursuant to the Federal Information Quality Act challenging a number of key reports upon which USFWS is expected to rely in making its listing decision. Moreover, in an effort to delay any potential action on the greater sage-grouse by the September 2015 deadline, Congress has passed a spending bill preventing USFWS from spending money in 2015 on rules that would protect the greater sage-grouse. Meanwhile, in May 2015, the BLM and the U.S. Forest Service issued a series of final Environmental Impact Statements ("EISs") for proposed land use plan amendments incorporating conservation measures for the greater sage-grouse in ten western states. The USFWS has stated that it will utilize these land use plans in its formal review of the greater sage-grouse listing status. BLM has stated that the EISs focus on conserving Priority Habitat areas that have been identified as having the highest value to maintaining the species and its habitat and contain land use measures designed to minimize or avoid habitat disturbance. BLM has also stated that the plans honor all valid, existing rights, including those for oil and gas development, rights-of-way, locatable minerals, and other

permitting projects. At a state level, Utah published a Conservation Plan for Greater Sage-grouse in Utah in 2013. The Utah Conservation Plan seeks to eliminate the threats facing sage-grouse populations while balancing the economic and social needs of the residents of Utah. Pursuant to the Utah Conservation Plan, extractive mineral activities in designated Sage Grouse Management Areas would be subject to management protocols designed to avoid or minimize disturbances to the sage-grouse population. Utah has submitted its Conservation Plan to the USFWS for its opinion on the sufficiency of the conservation provisions. USFWS began its review of the Plan in February 2013, and in February 2015, Governor Gary Herbert signed an Executive Order implementing the Plan. Certain of our mines may be located on or near lands designated as Priority Areas of Conservation for the greater sage-grouse as determined by USFWS and/or Sage Grouse Management Areas as determined by Utah's Public Lands Policy Coordination Office. However, we have not yet determined whether the Utah Conservation Plan or the addition of the greater sage-grouse to the list of threatened species would impact our operations. If a USFWS listing determination results, it could lead to new land use restrictions to protect the greater sage-grouse. Should more stringent protective measures be applied to protect the greater sage-grouse, this could result in increased operating costs, heightened difficulty in obtaining future mining permits, or the need to implement additional mitigation measures, thereby impacting our mining operations and costs.

Other Environmental Laws

We are required to comply with numerous other federal, state and local environmental laws in addition to those previously discussed. These additional laws include, for example, the Safe Drinking Water Act, the Toxic Substance Control Act and the Emergency Planning and Community Right-to-Know Act.

Permits

Mining companies must obtain numerous permits that impose strict regulations on various environmental and safety matters. These provisions include requirements for building dams; coal prospecting; mine plan development; topsoil removal, storage and replacement; protection of the hydrologic balance; subsidence control for underground mines; subsidence and surface drainage control; mine drainage and mine discharge control and treatment; and re-vegetation.

The mining permit application process is initiated by collecting baseline data to adequately characterize the pre-mine environmental condition of the permit area. This work includes surveys of cultural resources, soils, vegetation, wildlife, assessment of surface and ground water hydrology, climatology and wetlands. In conducting this work, we collect geologic data to define and model the soil and rock structures and coal that we will mine. We develop mine and reclamation plans by utilizing this geologic data and incorporating elements of the environmental data. The mine and reclamation plan incorporates the provisions of the SMCRA, the state programs and the complementary environmental programs that affect coal mining, including the CWA.

Required permits include mining and reclamation permits under the SMCRA, issued by the Utah Department of Natural Resources Division of Oil, Gas and Mining, and wastewater discharge, or NPDES, permits under the CWA, issued by the Utah Department of Environmental Quality Division of Water Quality. In addition to the required permits, for surface operations, mining companies may also need to obtain air quality permits from Utah Department of Environmental Quality Division of Air Quality. In addition, MSHA approval for ventilation, roof control and numerous specific surface and underground operations must be obtained and maintained. The authorization and permitting requirements imposed by these and other governmental agencies are costly and may delay development or continuation of mining operations. Due to the fact that the application review process may take years to complete and permit applications are increasingly being challenged by environmental and other

advocacy groups, we may experience difficulty or delays in obtaining mining permits or other necessary approvals, or even face denials of permits altogether.

Once a permit application is prepared and submitted to the regulatory agency, it goes through a completeness review, technical review and public notice and comment period before it can be approved. Some SMCRA and CWA permits can take over a year to prepare, depending on the size and complexity of the mine and often take six months or years to receive approval. Regulatory authorities have considerable discretion in the timing of the permit issuance and the public has rights to comment on and otherwise engage in the permitting process, including through intervention in the courts.

Currently, we have the necessary permits for mining operations at each of our three mines. Continued and expanded operations will require additional or renewed permits. These additional permits may include significant permit revisions to the SMCRA mining permit and fill and dredge permits for mining of additional coal panels; new NPDES, new SMCRA, new impounding, and possible CWA permits for additional refuse areas; and revisions to the SMCRA permit and a NPDES construction permit for additional bleeder shafts. Due to various and, sometimes, interrelated requirements from different agencies, it is not possible to predict an average or approximate time frame required to obtain all permits and approvals to operate new or expanded mines. In addition, expanded permitting activity and/or challenges from environmental groups may increase the various agencies' permit and approval review time in the future, and may create uncertainty about our ability to utilize permits that may be the subject of any appeal.

Our customers may face similar permitting challenges. In addition to the regulatory requirements applicable to electric generators described above, export terminals are also subject to permit requirements, as well as challenges from environmental organizations which may make it complicated or expensive to expand existing terminal capacity or open new export terminals in a timely and cost-effective manner. Demand for our coal could be constrained by export terminal capacity, which may materially impact our results or operations.

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MANAGEMENT

Management of Bowie Resource Partners LP

We are managed and operated by the board of directors and executive officers of our general partner, Bowie GP, LLC, a wholly-owned subsidiary of our sponsor. As a result of owning our general partner, our sponsor will have the right to appoint all members of the board of directors of our general partner, including at least three directors meeting the independence standards established by the NYSE. At least one of our independent directors will be appointed prior to the date our common units are listed for trading on the NYSE. Our unitholders will not be entitled to elect our general partner or its directors or otherwise directly participate in our management or operations. Our general partner owes certain contractual duties to our unitholders as well as a fiduciary duty to its owners.

Upon the closing of this offering, we expect that our general partner will have seven directors, at least one of whom will be independent as defined under the standards established by the NYSE and the Exchange Act. The NYSE does not require a listed publicly traded partnership, such as ours, to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating committee. However, our general partner is required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act, subject to certain transitional relief during the one-year period following consummation of this offering. Our sponsor will appoint at least one member of the audit committee to the board of directors of our general partner by the date our common units first trade on the NYSE.

In evaluating director candidates, our sponsor will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the board's ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of committees of the board to fulfill their duties.

All of the executive officers of our general partner listed below will allocate their time between managing our business and affairs and the business and affairs of our sponsor. The amount of time that our executive officers will devote to our business and the business of our sponsor will vary in any given year based on a variety of factors. Our executive officers intend, however, to devote as much time to the management of our business and affairs as is necessary for the proper conduct of our business and affairs. Following the consummation of this offering and after giving effect to the closing of the Utah Transaction, we expect that our executive officers, on average, will devote at least 50% of their time to our operations. However, the amount of time that our executive officers actually devote to our operations may fluctuate and cannot be predicted with certainty and will also be dependent on future acquisition activities and other operational requirements of our sponsor.

Following the consummation of this offering, neither our general partner nor our sponsor will receive any management fee or other compensation in connection with our general partner's management of our business, but we will reimburse our general partner and its affiliates, including our sponsor, for all expenses they incur and payments they make on our behalf. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Please read "Certain Relationships and Related Party Transactions."

Certain executive officers of our general partner hold a profits interest in our sponsor.

Executive Officers and Directors of Our General Partner

The following table shows information for the executive officers and directors of our general partner upon the consummation of this offering. Directors hold office until their successors have been

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elected or qualified or until the earlier of their death, resignation, removal or disqualification. Executive officers serve at the discretion of the board. There are no family relationships among any of our directors or executive officers. Some of our directors and all of our executive officers also serve as directors and executive officers of our sponsor.

Name	Age (as of December 31, 2014)	Position With Our General Partner
John J. Siegel	65	Chairman of the Board of Directors
Johannes ("Manie") H. Dreyer	44	Chief Executive Officer, Director
Eugene ("Gene") E. DiClaudio	62	Chief Operating Officer
James J. Wolff	57	Chief Financial Officer
Grant S. Quasha	35	Chief Commercial Officer
Brian S. Settles	35	Senior Vice President, Secretary and General Counsel
John DeRosa	54	Director Nominee
Jesus Fernandez	38	Director Nominee
Carlos Pons	33	Director Nominee
Steve Rickmeier	67	Director Nominee

John J. Siegel has over 30 years of experience as a founder and operator of vertically-integrated coal companies. Among individual holders, he owns the largest equity share of our sponsor. Mr. Siegel is also the co-owner and operator of Bowie Refined Coal, LLC and ClearStack Power LLC. Previously, he was the founder and operator of each of Green Bay Fuels, Inc., Jader Coal, LLC, Northwestern Synfuels, LLC and Sentinel Energy, Inc. Mr. Siegel holds a Bachelor of Arts degree from St. Joseph's College in Rensselaer, Indiana. He attended law school at the University of Louisville.

We believe Mr. Siegel's extensive knowledge of the coal industry and his wealth of management experience within the industry make him a valuable asset to the board of directors of our general partner.

Johannes ("Manie") H. Dreyer has over 20 years of experience in the mining and minerals industry. His career spans a broad range of commodities, having spent the majority of his time in leadership roles within the coal industry. Throughout his career, Mr. Dreyer has worked in operational and engineering projects, business development, as well as marketing and sales across three continents. He most recently served as President of BHP Billiton Energy Coal South Africa from 2009 to 2014. Prior to that, Mr. Dreyer held a number of executive, operating and commercial positions within BHP Billiton's business divisions in the United States, South Africa, and Singapore. Mr. Dreyer serves as a director and executive committee member of the World Coal Association, whilst he previously served as a director of the Richards Bay Coal Terminal in South Africa as well as a director and council member for the South African Chamber of Mines. He holds a bachelor's degree in electrical engineering from the Rand Afrikaans University (South Africa) as well as a master's degree in business leadership from the University of South Africa.

We believe Mr. Dreyer's extensive professional and leadership experience within the mining and minerals industry, including his tenure at BHP Billiton, make him well-qualified to serve as a member of the board of directors of our general partner.

Eugene ("Gene") E. DiClaudio has 40 years of experience in the coal industry. Prior to joining our sponsor, he was the President of the Arch Western Bituminous Group since 2005, where he oversaw the operations of the Sufco, Skyline, Dugout Canyon and West Elk mines and was responsible for all operational results, including Health & Safety, Environmental Compliance, Engineering, Purchasing, Process Improvement and Human Resources. Previously, Mr. DiClaudio was president of Mountain Coal and held senior executive positions at ARCO Coal and BP Coal. He holds a Bachelor of Science

degree in Mining Engineering from Pennsylvania State University and holds the Pennsylvania Mine Foreman Certificate.

James J. Wolff has been the chief financial officer of our sponsor since 2011. He has over 30 years of experience in the energy and transportation industries, with a diverse background in finance, operations and business development. Mr. Wolff possesses substantial IPO, M&A and divestitures experience with companies generating revenues between $300 million and $8 billion. Prior to joining our sponsor, he was CFO of U.S. Coal Corporation and has held senior executive positions with Energy Coal Resources, American Commercial Lines and CSX Corporation. Mr. Wolff holds a Bachelor of Arts degree in Economics from the University of Texas and attended South Texas College of Law.

Grant S. Quasha joined our sponsor in 2013 as Senior VP, Business Development. He was promoted to Chief Commercial Officer in 2014 and is responsible for Business Development, Strategy, Sales and Marketing. Mr. Quasha has over 10 years of experience in the commodity and finance industries. Prior to joining our sponsor, he was the North American Manager of Corporate and Structured Finance at Trafigura and an Associate at JPMorgan Chase & Co., focused on the mining industry. Mr. Quasha began his career as an oil tanker broker at Poten & Partners. He holds a Bachelor of Arts degree, *cum laude*, from Harvard College and a Master of Business Administration degree with Distinction from Harvard Business School.

Brian S. Settles joined our sponsor in August 2013 and has served as Senior Vice President, Secretary and General Counsel since that time. Prior to joining our sponsor, Mr. Settles practiced law with Fultz Maddox Hovious & Dickens, PLC, Greenebaum Doll & McDonald PLLC and Taft Stettinius & Hollister LLP, specializing in mergers and acquisitions, corporate law and natural resources law. Mr. Settles holds a Bachelor of Arts degree in Finance from Miami University, *magna cum laude*, and a Juris Doctor degree from the University of Kentucky College of Law, *summa cum laude*.

John DeRosa is a nominee for the board of directors of our general partner. Mr. DeRosa is a member of the board of directors of our sponsor. He has over 25 years of experience in the financial services industry and is currently the Head of Tax for the Americas for Deutsche Bank. In his role, he is responsible for all tax matters for Deutsche Bank's operations in the U.S., Latin America and Canada. Deutsche Bank Securities Inc. is acting as an underwriter in connection with this offering. Prior to joining Deutsche Bank, Mr. DeRosa was the Global Head of Tax for Lehman Brothers, the Head of Tax for The Bank of New York, a Director in the Structured Transactions Group at Morgan Stanley and a tax partner in the Financial Services group of Ernst & Young. Mr. DeRosa is a CPA. He earned his B.A. in Political Science from Haverford College and his M.B.A in accounting from Rutgers University.

We believe Mr. DeRosa's wealth of experience and expertise in the financial services industry will provide him with unique insight that we expect will be valuable to the board of directors of our general partner.

Jesus Fernandez is a nominee for the board of directors of our general partner. Mr. Fernandez is a member of the board of directors of our sponsor. Mr. Fernandez has over 15 years of experience in mining investments and commodities financing. He established the Trafigura Group's mining investment arm in 2005, and he currently heads the mining investment team at Galena. Mr. Fernandez is a board member of a number of companies including Trafigura Group's mining division, Cadillac Ventures and Mawson West. Prior to joining the Trafigura Group, he worked in the project finance team at International Power plc in London. Mr. Fernandez has a Master of Science degree (Finance and Investment) from the University of Exeter and a Licenciatura (Economics degree) from the Universidad de Cantabria, Spain.

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We believe Mr. Fernandez's substantial industry experience, including at the Trafigura Group and Galena, will enable him to provide essential guidance to the board of directors of our general partner.

Carlos Pons is a nominee for the board of directors of our general partner. Mr. Pons is a member of the board of directors of our sponsor. Mr. Pons has over ten years of experience in M&A, investments and financing in mining and natural resources. He started his career at Goldman Sachs and worked in its London and Moscow offices where he was involved in numerous merger, acquisition and capital markets transactions. Most recently, Mr. Pons worked for Ural Invest as Vice President for investments and executed mining and infrastructure investments in Russia and Africa. Mr. Pons joined Galena in 2013 from Glencore's oil department, where his main focus was M&A. He has a B.A. in Business Administration from ICADE Madrid, Spain.

Based upon his strong background in various aspects of the mining and natural resources industry, we believe Mr. Pons has the requisite set of skills to serve as a director of our general partner.

Steve Rickmeier is a nominee for the board of directors of our general partner. Mr. Rickmeier is a member of the board of directors of our sponsor and has over 30 years of experience in the tax-related finance industry, including as Managing Director of the Energy Finance Group of GE Capital Corporation from 1992 to 1997 and as Managing Director of The Deerpath Group LLC from 1979 to 1991. Previously, Mr. Rickmeier served as Vice President-Director of Lease Financing for ITT Industrial Credit from 1977 to 1979 and as Manager-Industrial Leasing at the Leasing and Industrial Loans Group of GE Capital Corporation from 1972 to 1977. Mr. Rickmeier is one of the principal equity owners of our sponsor. He is also an owner of Bowie Refined Coal, LLC and Clearstack Power, LLC, as well as the co-founder of Northwestern Synfuels, Sentinel Energy and Loyola Synfuels. Mr. Rickmeier received a B.A. from Northwestern University in 1969 and an M.B.A. from Loyola University of Chicago in 1972.

We believe Mr. Rickmeier's extensive experience in the financial sector and the coal industry make him well-qualified to serve as a member of the board of directors of our general partner.

Director Independence

In accordance with the rules of the NYSE, our general partner must have at least one independent director prior to the listing of our common units on the NYSE, one additional member within three months of the effectiveness of the registration statement of which this prospectus forms a part, and one additional independent member within 12 months of that date.

Committees of the Board of Directors

The board of directors of our general partner will have an audit committee and a conflicts committee. We do not expect that we will have a compensation committee, but rather that the board of directors of our general partner will approve equity grants to directors and employees.

Audit Committee

We are required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act, subject to certain transitional relief during the one-year period following consummation of this offering as described above. The audit committee will assist the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee will have the sole authority to (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm, and (3) pre-approve any non-audit services and tax services to be rendered by our

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independent registered public accounting firm. The audit committee will also be responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm will be given unrestricted access to the audit committee and our management.

Conflicts Committee

At least one independent member of the board of directors of our general partner will serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest and determines to submit to the conflicts committee for review. The conflicts committee will determine if the resolution of the conflict of interest is adverse to the interest of the partnership. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, including our sponsor, and must meet the independence standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors. In addition, the members of our conflicts committee may not own any interest in our general partner or its affiliates (other than common units or awards under our long-term incentive plan) that is determined by the board of directors of our general partner to have an adverse impact on the ability of such director to act in an independent manner with respect to the matter submitted to the conflicts committee. Any matters approved by the conflicts committee will be conclusively deemed to be approved by us and all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders.

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EXECUTIVE COMPENSATION

We and our general partner were formed in January 2015 and had no material assets or operations until immediately prior to the closing of this offering. Accordingly, neither we nor our general partner has accrued or will accrue any cost or liability with respect to management compensation or retirement benefits for directors or executive officers for any periods prior to our formation date or the date of this offering. As a result, we have no historical compensation information present. We currently do not have a compensation committee.

All of the executive officers of our general partner will be employed by our sponsor, and will allocate their time between managing our business and managing the business of our sponsor. Since all of our executive officers will be employed by our sponsor, the responsibility and authority for compensation-related decisions for our executive officers generally will reside with our sponsor. Any such compensation decisions will not be subject to any approvals by the board of directors of our general partner or any committees thereof. However, any and all determinations with respect to awards that may be made to our executive officers, key employees or directors under any long-term incentive plan we adopt will be made by the board of directors of our general partner or a committee thereof that may be established for such purpose. Please read the description of the long-term incentive plan we intend to adopt prior to the completion of this offering ("LTIP") below under the heading "—Long-Term Incentive Plan."

The executive officers of our general partner may participate in employee benefit plans and other compensation arrangements maintained by our sponsor, including plans that may be established in the future. Our executive officers currently have employment agreements with our sponsor that we anticipate will continue in effect following this offering, the material terms of which are described below. Except with respect to any awards that may be granted under the LTIP, we do not anticipate that our executive officers will receive separate amounts of compensation in relation to the services they provide to us. In accordance with the terms of our partnership agreement and omnibus agreement, we will reimburse our sponsor for compensation-related expenses attributable to the portion of the executive's time dedicated to providing services to us. Please read "The Partnership Agreement—Reimbursement of Expenses" and "Certain Relationships and Related Party Transactions—Agreements with Affiliates in Connection with the Transactions—Omnibus Agreement." Although we will bear an allocated portion of our sponsor's costs of providing compensation and benefits to employees who serve as executive officers of our general partner, we will have no control over such costs and will not establish or direct the compensation policies or practices of our sponsor.

Employment Agreements

The employment agreements between our executive officers and our sponsor were entered into in 2013 (in the case of Mr. Dreyer, 2014) and each has a three year term, which may be extended by mutual written agreement. The employment agreements provide the executive officers with (i) an annual base salary, which is subject to annual review and may be modified by the board of directors of our sponsor in its discretion; (ii) an annual bonus opportunity (A) in the case of Mr. DiClaudio, in an amount up to 125% of base salary based on the attainment of certain financial, safety and other performance criteria, and (B) in the case of our other executive officers, in an amount up to 50% of base salary (125% of base salary, in the case of Mr. Dreyer) in the discretion of the board of directors of our sponsor; (iii) a profits interest in our sponsor, as described below under "Certain Relationships and Related Party Transactions—Agreements with Affiliates in Connection with the Transactions—Ownership Interests in our Sponsor and Arrangements with Management"; and (iv) the right to participate in all benefit plans, programs and policies offered to salaried employees subject to applicable eligibility requirements. Specifically, the employment agreements established the following annual base salary rates for the executive officers: (a) Mr. Dreyer—$650,000, (b) Mr. DiClaudio—$500,000, (c) Mr. Wolff—$350,000, (d) Mr. Quasha—$330,000, and (e) Mr. Settles —$250,000. The

employment agreements also provide that the executive officers will be reimbursed for reasonable business and other expenses incurred in furtherance of their duties.

If the employment one of our executive officers with the sponsor is terminated without "cause" or for "good reason," then the executive officer will receive, subject to the execution of a general release of claims, (i) a lump sum payment equal to (A) 1.5 times annual base salary, plus (B) the bonus amount received for the prior calendar year (for Mr. Dreyer, the lump sum payment is equal to two times annual base salary), and (ii) reimbursement for premiums for continued medical coverage if elected under COBRA for up to one year (up to 18 months, in the case of Mr. Dreyer). For these purposes, (a) "cause" generally means (1) breach of the employment agreement by executive that is not cured within 30 days of written notice from our sponsor, (2) dishonest, fraudulent or unlawful conduct or gross negligence or willful misconduct involving the sponsor's business or affairs that results in economic harm to the sponsor, or (3) a plea of nolo contendere to or conviction for a felony involving moral turpitude (or, in the case of Mr. Dreyer, being charged with any crime that is related to his employment or that is punishable other than only by a fine or other non-custodial penalty); and (b) "good reason" generally means (1) a material diminution of the executive's duties, responsibilities or authority, (2) a geographic relocation of the executive's primary office location, (3) a reduction in the executive's base salary, or (4) breach of the employment agreement by our sponsor that is not cured within 30 days of written notice from the executive. The employment agreements contain certain indemnification rights, confidentiality and non-disparagement covenants, which are perpetual in duration, and certain non-solicitation and non-competition covenants, which extend for one to two years following the executive's termination of employment.

We do not have any liabilities or obligations under the employment agreements, other than by virtue of our reimbursement obligations under our partnership agreement and omnibus agreement.

Long-Term Incentive Plan

In order to incentivize our management and directors following the completion of this offering to continue to grow our business, the board of directors of our general partner intends to adopt a long-term incentive plan, or the LTIP, for employees, officers, consultants and directors of our general partner and any of its affiliates, including our sponsor, who perform services for us. Our general partner intends to implement the LTIP prior to the completion of this offering to provide maximum flexibility with respect to the design of compensatory arrangements for individuals providing services to us; however, at this time, neither we nor our general partner has made any decisions regarding any specific grants under the LTIP in conjunction with this offering or in the near term.

The description of the LTIP set forth below is a summary of the material features of the LTIP that our general partner intends to adopt. This summary, however, does not purport to be a complete description of all the provisions of the LTIP that will be adopted and represents only the general partner's current expectations regarding the LTIP. This summary is qualified in its entirety by reference to the LTIP, the form of which is filed as an exhibit to this registration statement. The purpose of the LTIP is to provide a means to attract and retain individuals who are essential to our growth and profitability and to encourage them to devote their best efforts to advancing our business by affording such individuals a means to acquire and maintain ownership of awards, the value of which is tied to the performance of our common units. We expect that the LTIP will provide for the grant of unit options, unit appreciation rights, restricted units, unit awards, phantom units, distribution equivalent rights, cash awards, performance awards, other unit-based awards and substitute awards (collectively, "awards"). These awards are intended to align the interests of employees, officers, consultants and directors with those of our unitholders and to give such individuals the opportunity to share in our long-term performance. Any awards that are made under the LTIP will be approved by the board of directors of our general partner or a committee thereof that may be established for such purpose. We will be responsible for the cost of awards granted under the LTIP.

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Administration

The LTIP will be administered by the board of directors of our general partner or an alternative committee appointed by the board of directors of our general partner, which we refer to together as the "committee" for purposes of this summary. The committee will administer the LTIP pursuant to its terms and all applicable state, federal, or other rules or laws. The committee will have the power to determine to whom and when awards will be granted, determine the amount of awards (measured in cash or in shares of our common units), proscribe and interpret the terms and provisions of each award agreement (the terms of which may vary), accelerate the vesting provisions associated with an award, delegate duties under the LTIP and execute all other responsibilities permitted or required under the LTIP. In the event that the committee is not comprised of "nonemployee directors" within the meaning of Rule 16b-3 under the Exchange Act, the full board of directors or a subcommittee of two or more nonemployee directors will administer all awards granted to individuals that are subject to Section 16 of the Exchange Act.

Securities to be Offered

The maximum aggregate number of common units that may be issued pursuant to any and all awards under the LTIP will not exceed common units, subject to adjustment due to recapitalization or reorganization, as provided under the LTIP. In addition, if any common units subject to any award are not issued or transferred, or cease to be issuable or transferable for any reason, including (but not exclusively) because units are withheld or surrendered in payment of taxes or any exercise or purchase price relating to an award or because an award is forfeited, terminated, expires unexercised, is settled in cash in lieu of common units, or is otherwise terminated without a delivery of units, those common units will again be available for issue, transfer, or exercise pursuant to awards under the LTIP, to the extent allowable by law. Common units to be delivered pursuant to awards under our LTIP may be common units acquired by our general partner in the open market, from any other person, directly from us, or any combination of the foregoing.

Awards

Unit Options

We may grant unit options to eligible persons. Unit options are rights to acquire common units at a specified price. The exercise price of each unit option granted under the LTIP will be stated in the unit option agreement and may vary; provided, however, that, the exercise price for an unit option must not be less than 100% of the fair market value per common unit as of the date of grant of the unit option unless that unit option is intended to otherwise comply with the requirements of Section 409A of the Code. Unit options may be exercised in the manner and at such times as the committee determines for each unit option, unless that unit option is determined to be subject to Section 409A of the Code, in which case the unit option will be subject to any necessary timing restrictions imposed by the Code or federal regulations. The committee will determine the methods and form of payment for the exercise price of a unit option and the methods and forms in which common units will be delivered to a participant.

Unit Appreciation Rights

A unit appreciation right is the right to receive, in cash or in common units, as determined by the committee, an amount equal to the excess of the fair market value of one common unit on the date of exercise over the grant price of the unit appreciation right. The committee will be able to make grants of unit appreciation rights and will determine the time or times at which a unit appreciation right may be exercised in whole or in part. The exercise price of each unit appreciation right granted under the LTIP will be stated in the unit appreciation right agreement and may vary; provided, however, that, the

exercise price must not be less than 100% of the fair market value per common unit as of the date of grant of the unit appreciation right, unless that unit appreciation right is intended to otherwise comply with the requirements of Section 409A of the Code.

Restricted Units

A restricted unit is a grant of a common unit subject to a risk of forfeiture, performance conditions, restrictions on transferability and any other restrictions imposed by the committee in its discretion. Restrictions may lapse at such times and under such circumstances as determined by the committee. The committee shall provide, in the restricted unit agreement, whether the restricted unit will be forfeited upon certain terminations of employment. Unless otherwise determined by the committee, a common unit distributed in connection with a unit split or unit dividend, and other property distributed as a dividend, will generally be subject to restrictions and a risk of forfeiture to the same extent as the restricted unit with respect to which such common unit or other property has been distributed.

Unit Awards

The committee will be authorized to grant common units that are not subject to restrictions. The committee may grant unit awards to any eligible person in such amounts as the committee, in its sole discretion, may select.

Phantom Units

Phantom units are rights to receive common units, cash or a combination of both at the end of a specified period. The committee may subject phantom units to restrictions (which may include a risk of forfeiture) to be specified in the phantom unit agreement that may lapse at such times determined by the committee. Phantom units may be satisfied by delivery of common units, cash equal to the fair market value of the specified number of common units covered by the phantom unit or any combination thereof determined by the committee. Except as otherwise provided by the committee in the phantom unit agreement or otherwise, phantom units subject to forfeiture restrictions may be forfeited upon termination of a participant's employment prior to the end of the specified period. Cash distribution equivalents may be paid during or after the vesting period with respect to a phantom unit, as determined by the committee.

Distribution Equivalent Rights

The committee will be able to grant distribution equivalent rights in tandem with awards under the LTIP (other than unit awards or an award of restricted units), or distribution equivalent rights may be granted alone. Distribution equivalent rights entitle the participant to receive cash equal to the amount of any cash distributions made by us during the period the distribution equivalent right is outstanding. Payment of cash distributions pursuant to a distribution equivalent right issued in connection with another award may be subject to the same vesting terms as the award to which it relates or different vesting terms, in the discretion of the committee.

Cash Awards

The LTIP will permit the grant of awards denominated in and settled in cash. Cash awards may be based, in whole or in part, on the value or performance of a common unit.

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Performance Awards

The committee may condition the right to exercise or receive an award under the LTIP, or may increase or decrease the amount payable with respect to an award, based on the attainment of one or more performance conditions deemed appropriate by the committee.

Other Unit-Based Awards

The LTIP will permit the grant of other unit-based awards, which are awards that may be based, in whole or in part, on the value or performance of a common unit or are denominated or payable in common units. Upon settlement, these other unit-based awards may be paid in common units, cash or a combination thereof, as provided in the award agreement.

Substitute Awards

The LTIP will permit the grant of awards in substitution for similar awards held by individuals who become employees, consultants or directors as a result of a merger, consolidation, or acquisition, by us or an affiliate, of another entity or the assets of another entity. Such substitute awards that are unit options or unit appreciation rights may have exercise prices less than 100% of the fair market value per common unit on the date of the substitution if such substitution complies with Section 409A of the Code and its regulations and other applicable laws and exchange rules.

Miscellaneous

Tax Withholding

At our discretion, and subject to conditions that the committee may impose, a participant's minimum statutory tax withholding with respect to an award may be satisfied by withholding from any payment related to an award or by the withholding of common units issuable pursuant to the award based on the fair market value of the common units.

Anti-Dilution Adjustments

If any "equity restructuring" event occurs that could result in an additional compensation expense under the applicable accounting guidance for stock-based compensation if adjustments to awards with respect to such event were discretionary, the committee will equitably adjust the number and type of units covered by each outstanding award and the terms and conditions of each such award to equitably reflect the restructuring event. With respect to a similar event that would not result in an accounting charge if adjustment to awards were discretionary, the committee shall have complete discretion to adjust awards in the manner it deems appropriate. In the event the committee makes any adjustment in accordance with the foregoing provisions, a corresponding and proportionate adjustment shall be made with respect to the maximum number of units available under the LTIP and the kind of units or other securities available for grant under the LTIP. Furthermore, in the case of (i) a subdivision or consolidation of the common units (by reclassification, split or reverse split or otherwise), (ii) a recapitalization, reclassification, or other change in our capital structure or (iii) any other reorganization, merger, combination, exchange, or other relevant change in capitalization of our equity, then a corresponding and proportionate adjustment shall be made in accordance with the terms of the LTIP, as appropriate, with respect to the maximum number of units available under the LTIP, the number of units that may be acquired with respect to an award, and, if applicable, the exercise price of an award, in order to prevent dilution or enlargement of awards as a result of such events.

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Change in Control

Upon a "change in control" (as defined in the LTIP), the committee may, in its discretion, (i) remove any forfeiture restrictions applicable to an award, (ii) accelerate the time of exercisability or vesting of an award, (iii) require awards to be surrendered in exchange for a cash payment, (iv) cancel unvested awards without payment or (v) make adjustments to awards as the committee deems appropriate to reflect the change in control.

Termination of Employment or Service

The consequences of the termination of a participant's employment, consulting arrangement or membership on the board of directors will be determined by the committee in the terms of the relevant award agreement.

Director Compensation

We and our general partner were formed in January 2015 and, as such, have not accrued or paid any obligations with respect to compensation for directors for any periods prior to our formation date or the date of this offering.

The executive officers or employees of our sponsor who also serve as directors of our general partner will not receive additional compensation for their service as a director of our general partner. Directors of our general partner who are not executive officers or employees of our sponsor will receive compensation as "non-employee directors" as set by our general partner's board of directors.

Effective as of the closing of this offering, each non-employee director will receive a compensation package that will consist of an annual cash retainer of $. In addition, our directors will be reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or its committees. Each non-employee director may receive grants of equity-based awards under the LTIP we intend to adopt prior to the completion of this offering from time to time for so long as he or she serves as a director.

Each member of the board of directors of our general partner will be indemnified for his actions associated with being a director to the fullest extent permitted under Delaware law.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the beneficial ownership of common units and subordinated units of Bowie Resource Partners LP that will be issued and outstanding upon the consummation of this offering and the related transactions and held by:

- our general partner;
- beneficial owners of 5% or more of our common units;
- each director and named executive officer of our general partner; and
- all directors and executive officers of our general partner as a group.

Unless otherwise noted, the address for each beneficial owner listed below is 6100 Dutchmans Lane, 9th Floor, Louisville, Kentucky 40205.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Common and Subordinated Units Beneficially Owned
Bowie GP, LLC	—	—	—	—	—
Bowie Resource Holdings, LLC(1)(2)		%		100%	%
John J. Siegel		%	—	—	%
Johannes H. Dreyer		%	—	—	%
Eugene E. DiClaudio		%	—	—	%
James J. Wolff		%	—	—	%
Grant S. Quasha		%	—	—	%
Brian S. Settles		%	—	—	%
John DeRosa		%	—	—	%
Jesus Fernandez		%	—	—	%
Carlos Pons		%	—	—	%
Steve Rickmeier		%	—	—	%
		%	—	—	%
All directors and executive officers as a group (persons)		%	—	—	%

* Less than 1%

(1) Voting and investment power over securities held by Bowie Resource Holdings, LLC are made by .

(2) If the underwriters exercise in full their option to purchase additional common units, Bowie Resource Holdings, LLC will beneficially own common units, or % of the total common units outstanding.

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

After this offering, assuming that the underwriters do not exercise their option to purchase additional common units, our sponsor will own, directly or indirectly, common units and subordinated units, representing an aggregate of approximately % limited partner interest in us (excluding the incentive distribution rights, which cannot be expressed as a fixed percentage), and will own and control our general partner. Our sponsor will also appoint all of the directors of our general partner, which will own a non-economic general partner interest in us and will own the incentive distribution rights.

The terms of the transactions and agreements disclosed in this section were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations. These terms are not necessarily at least as favorable to the parties to these transactions and agreements as the terms that could have been obtained from unaffiliated third parties.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with the formation, ongoing operation and any liquidation of Bowie Resource Partners LP.

Formation Stage	
The aggregate consideration received by our general partner and its affiliates for the contribution of their interests	common units, subordinated units and all of our incentive distribution rights; and $ million of net proceeds from this offering and our offering of the New Notes to our sponsor, in part as reimbursement for capital expenditures. Any net proceeds received from the exercise of the underwriters' option to purchase additional common units will be used to make a distribution to our sponsor, in part as reimbursement for capital expenditures. If the underwriters do not exercise this option in full or at all, the common units that would have been sold to the underwriters had they exercised the option in full will be issued to our sponsor for no additional consideration at the expiration of the option period.
Operational Stage	
Distributions of cash available for distribution to our general partner and its affiliates	We will generally make cash distributions 100% to our unitholders, including affiliates of our general partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner will be entitled to increasing percentages of the distributions, up to 50.0% of the distributions above the highest target distribution level. Assuming we have sufficient cash available for distribution to pay the full minimum quarterly distribution on all of our outstanding common units and subordinated units for four quarters, our general partner and its affiliates would receive an annual distribution of approximately $ million on their units.

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Payments to our general partner and its affiliates	Our general partner will not receive a management fee or other compensation for its management of our partnership, but we will reimburse our general partner and its affiliates for all direct and indirect expenses they incur and payments they make on our behalf. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us. Additionally, in connection with this offering, we expect to enter into an omnibus agreement with our sponsor, pursuant to which we will reimburse our sponsor on a cost-of-services basis for certain services performed on our behalf. We expect that we will reimburse our sponsor and our general partner approximately $15.7 million in total for services performed under the partnership agreement and the omnibus agreement during the twelve months ending June 30, 2016.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its non-economic general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests. Please read "The Partnership Agreement—Withdrawal or Removal of Our General Partner."
Liquidation Stage	
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements with Affiliates in Connection with the Transactions

In connection with the closing of this offering, we expect to enter into certain agreements with our sponsor, as described in more detail below.

Contribution Agreement

We expect to enter into a contribution agreement that will effect the contribution by our sponsor of the ownership interests in our operating company and its subsidiaries, including CFC, to us, and the use of the net proceeds of this offering and our offering of the New Notes. Please read "—Distributions and Payments to Our General Partner and Its Affiliate—Formation Stage" for the aggregate consideration to be received by our sponsor for the contribution of its interests. While we believe this agreement is on terms no less favorable to any party than those that could have been negotiated with an unaffiliated third party, it will not be the result of arm's-length negotiations. All of the transaction expenses incurred in connection with these transactions will be paid from the proceeds of this offering and our offering of the New Notes.

Registration Rights Agreement

We expect to enter into a registration rights agreement with our sponsor pursuant to which we may be required to register the sale of the (i) common units issued (or issuable) to our sponsor pursuant to the contribution agreement, (ii) subordinated units and (iii) common units issuable upon conversion of

the subordinated units pursuant to the terms of the partnership agreement (together, the "Registrable Securities") it holds. Under the registration rights agreement, our sponsor will have the right to request that we register the sale of Registrable Securities held by it, and our sponsor will have the right to require us to make available shelf registration statements permitting sales of Registrable Securities into the market from time to time over an extended period, subject to certain limitations. Alternatively, we may be required to undertake a future public or private offering of common units and use the net proceeds from such offering to redeem an equal number of common units held by our sponsor. In addition, the registration rights agreement gives our sponsor piggyback registration rights under certain circumstances. The registration rights agreement also includes provisions dealing with indemnification and contribution and allocation of expenses. All of the Registrable Securities held by our sponsor and any permitted transferee will be entitled to these registration rights.

Omnibus Agreement

In connection with the closing of this offering, we will enter into an omnibus agreement with our sponsor and our general partner that will address certain aspects of our relationship with them, including:

- *Right of First Refusal.* If our sponsor or any of its affiliates decides to sell, convey or otherwise transfer any coal assets or coal export terminals pursuant to a bona fide third-party offer, we will have a right of first refusal with respect to such assets. In the event our sponsor decides to sell, convey or otherwise transfer such assets, it will provide us with notice of the material terms and conditions of such offer, including the proposed price for such assets. If we do not exercise our right of first refusal within 30 days of our receipt of such notice, our sponsor shall have the right to complete the third party offer. If the seller fails to complete such a transaction within 270 days, then the right of first refusal is reinstated. This right of first refusal shall apply only so long as our sponsor controls us.

- *Indemnity.* Our sponsor will indemnify us with respect to certain matters set forth in the omnibus agreement:

  - ***Environmental Remediation.*** So long as we make a claim before the third anniversary of the closing date, our sponsor will indemnify us to the full extent of any environmental remediation arising out of events or circumstances occurring before the closing of this offering, except for any liability or increase in liability as a result of changes in environmental regulations, provided however that we must bear the first $500,000 of such remediation costs, and our sponsor's liability for such remediation costs will not exceed $5 million.

  - ***Tax Matters.*** Our sponsor will fully indemnify us with respect to any tax liability arising prior to or in connection with the closing of this offering.

  - ***Post-closing.*** We will indemnify our sponsor for events relating to our operations after the closing of this offering except to the extent that we are entitled to indemnification by our sponsor.

- *License.* Our sponsor will grant us a royalty-free license to use the name "Bowie" and related marks. Additionally, our sponsor will grant us a non-exclusive right to use all of our sponsor's current and future technology. We have not paid and will not pay a separate license fee for the rights we receive under the license.

- *Expenses and Reimbursement.* Our sponsor will continue to provide us with certain general and administrative services, and we will reimburse our sponsor for all direct costs and expenses incurred on our behalf and the portion of our sponsor's overhead costs and expenses attributable to our operations. Additionally, the partnership will agree to pay (i) all fees in connection with the New Notes offering; (ii) all fees due under the new revolving credit facility; (iii) all fees in connection with any future financing arrangement entered into for the purpose of replacing the

new revolving credit facility or the New Notes; and (iv) all fees, commissions and issuance costs due in connection with this offering.

The omnibus agreement can be amended by written agreement of all parties to the agreement. However, the partnership may not agree to any amendment or modification that would, in the reasonable discretion of our general partner, be adverse in any material respect to the holders of our common units without prior approval of the conflicts committee. So long as our sponsor controls our general partner, the omnibus agreement will remain in full force and effect unless mutually terminated by the parties. If our sponsor ceases to control our general partner, the omnibus agreement will terminate, provided (i) the indemnification obligations described above and (ii) our non-exclusive right to use all of our sponsor's technology will remain in full force and effect in accordance with their terms.

Coal Supply Agreement with Our Sponsor

We expect to enter into a coal supply agreement with our sponsor pursuant to which it will purchase substantially all of our coal on substantially the same terms as our sponsor's agreements with our end customers. Pursuant to the coal supply agreement, our sponsor will purchase our coal, in the quantities and of the quality and from the mines specified in our sponsor's agreements with our end customers, and will sell our coal to the end customers under each such agreement between our sponsor and our end customers. Our sponsor will pay us the contracted price it receives from end customers of our coal, less certain fees and expenses.

Pursuant to the coal supply agreement, we will deliver coal to our sponsor FOB mine. To the extent that our sponsor has discretion in determining the source, quantity and delivery timing under any agreement with an end customer, we will have the right to direct our sponsor's exercise of such discretion. Our sponsor will agree to satisfy its obligations to supply coal to end customers first using coal purchased from us pursuant to the coal supply agreement, to the extent our coal meets the quality, quantity and location specifications under our sponsor's agreements with end customers.

The coal supply agreement will become effective upon the closing of this offering and will terminate upon the first to occur of (i) mutual agreement of the parties to terminate the agreement, (ii) the date on which all of the applicable coal supply agreements between our sponsor and end customers have been assigned to us, (iii) the date on which all of our sponsor's obligations under the applicable coal supply agreements between our sponsor and end customers have terminated, (iv) our acquisition from our sponsor of our sponsor's wholly owned subsidiary, Bowie Coal Sales, LLC or (v) termination by us or our sponsor in the event of a breach of a material provision of the agreement by our sponsor or us, respectively.

Coal Services Agreement

Trafigura BV owns Galena Asset Management, which manages Galena. Galena owns a 46% interest in our sponsor. Trafigura BV also owns Trafigura AG, which is the exclusive marketer of our uncommitted coal pursuant to a Coal Services Agreement. Pursuant to the Coal Services Agreement, Trafigura AG is the exclusive provider of certain sales, marketing, administrative and other services to us and our sponsor for the production life of our reserves. We and our sponsor pay Trafigura AG a sales fee equal to a percentage of the price paid per ton (FOB mine) delivered under the Coal Services Agreement, provided that the sales fee may be increased for export sales of coal above certain price per ton thresholds. Trafigura AG has the right to terminate the Coal Services Agreement upon 180 days' notice. We and our sponsor have a right to terminate the Coal Services Agreement with respect to any mine only upon a sale of such mine to a third party. For the year ended December 31, 2014, our sponsor paid Trafigura AG approximately $3.6 million pursuant to the Coal Services Agreement.

Upon the closing of this offering, we expect to terminate the existing Coal Services Agreement among CFC, our sponsor and Trafigura AG and to enter into a new Coal Services Agreement among

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our operating company and its subsidiaries, our sponsor and Trafigura AG, with substantially the same terms and conditions as the existing Coal Services Agreement.

Bowie Refined Coal Agreement

We expect to enter into an agreement with Bowie Refined Coal, LLC, an affiliate of our sponsor, providing us with a right of first refusal to acquire certain refined coal projects that it owns. The agreement can be amended by written agreement of all parties to the agreement. However, the partnership may not agree to any amendment or modification that would, in the reasonable discretion of our general partner, be adverse in any material respect to the holders of our common units without prior approval of the conflicts committee. So long as our sponsor controls our general partner, the agreement will remain in full force and effect unless mutually terminated by the parties. If our sponsor ceases to control our general partner, the agreement will terminate.

Ownership Interests in our Sponsor and Arrangements with Management

Messrs. Siegel and Rickmeier directly or indirectly own or control Cedars, which has a 54% ownership interest in our sponsor. We expect that Cedars will receive $ million (or $ million if the underwriters exercise their option to purchase additional units) of the net proceeds from this offering as a result of the distribution by our sponsor of a portion of the proceeds it receives from us. In addition, certain executive officers of our general partner hold non-voting profits interests in our sponsor that entitle them to share in distributions by our sponsor above specified levels. It is not anticipated that the specified ceiling amount with respect to such interests will be attained in connection with this offering. However, pursuant to sponsor-level bonus arrangements, we expect Messrs. Dreyer, DiClaudio, Wolff, Quasha and Settles will receive an aggregate of $ million (or $ million if the underwriters exercise their option to purchase additional units) in connection with the cash distribution by our sponsor of a portion of the net proceeds from this offering.

Procedures for Review, Approval and Ratification of Transactions with Related Persons

We expect that the board of directors of our general partner will adopt policies for the review, approval and ratification of transactions with related persons. We anticipate the board will adopt a written code of business conduct and ethics, under which a director would be expected to bring to the attention of the chief executive officer or the board any conflict or potential conflict of interest that may arise between the director or any affiliate of the director, on the one hand, and us or our general partner on the other. The resolution of any such conflict or potential conflict should, at the discretion of the board in light of the circumstances, be determined by a majority of the disinterested directors.

If a conflict or potential conflict of interest arises between our general partner or its affiliates, on the one hand, and us or our unitholders, on the other hand, the resolution of any such conflict or potential conflict should be addressed by the board of directors of our general partner in accordance with the provisions of our partnership agreement. At the discretion of the board in light of the circumstances, the resolution may be determined by the board in its entirety or by a conflicts committee meeting the definitional requirements for such a committee under our partnership agreement.

Upon our adoption of our code of business conduct, we would expect that any executive officer will be required to avoid conflicts of interest unless approved by the board of directors of our general partner.

Please read "Conflicts of Interest and Fiduciary Duties—Conflicts of Interest" for additional information regarding the relevant provisions of our partnership agreement.

The code of business conduct and ethics described above will be adopted in connection with the closing of this offering, and as a result, the transactions described above were not reviewed according to such procedures.

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CONFLICTS OF INTEREST AND FIDUCIARY DUTIES

Summary of Applicable Duties

The Delaware Revised Uniform Limited Partnership Act, which we refer to as the Delaware Act, provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the fiduciary duties otherwise owed by the general partner to the limited partners and the partnership. Our partnership agreement contains provisions that eliminate and replace the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. Our partnership agreement also specifically defines the remedies available to unitholders for actions taken that, without these defined liability standards, might constitute breaches of fiduciary duty under applicable Delaware law.

When our general partner is acting in its capacity as our general partner, as opposed to in its individual capacity, it must act in "good faith," meaning it must act in a manner that it believes is not adverse to our interest. This duty to act in good faith is the default standard set forth under our partnership agreement and our general partner will not be subject to any higher standard.

Our partnership agreement specifies decisions that our general partner may make in its individual capacity, and permits our general partner to make these decisions free of any contractual or other duty to us or our unitholders. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its call right, its voting rights with respect to any units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation or amendment of the partnership agreement.

When the directors and officers of our general partner cause our general partner to manage and operate our business, the directors and officers must cause our general partner to act in a manner consistent with our general partner’s applicable duties. However, the directors and officers of our general partner have fiduciary duties to manage our general partner, including when it is acting in its capacity as our general partner, in a manner beneficial to our sponsor.

Conflicts may arise as a result of the duties of our general partner and its directors and officers to act for the benefit of its owners, which may conflict with our interests and the interests of our public unitholders. Where the directors and officers of our general partner are causing our general partner to act in its capacity as our general partner, the directors and officers must cause the general partner to act in good faith, meaning they cannot cause the general partner to take an action that they believe is adverse to our interest. However, where a decision by our general partner in its capacity as our general partner is not clearly not adverse to our interest, the directors of our general partner may determine to submit the determination to the conflicts committee for review or to seek approval by the unitholders, as described below.

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its directors, officers and owners (including our sponsor) on the one hand, and us and our limited partners, on the other hand.

Whenever a conflict arises between our general partner or its owners, on the one hand, and us or our limited partners, on the other hand, the resolution, course of action or transaction in respect of such conflict of interest shall be conclusively deemed approved by us and all our limited partners and shall not constitute a breach of our partnership agreement, of any agreement contemplated thereby or of any duty, if the resolution, course of action or transaction in respect of such conflict of interest is:

- approved by the conflicts committee of our general partner; or

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- approved by the holders of a majority of the outstanding common units, excluding any such units owned by our general partner or any of its affiliates.

Our general partner may, but is not required to, seek the approval of such resolutions or courses of action from the conflicts committee of its board of directors or from the holders of a majority of the outstanding common units as described above. If our general partner does not seek approval from the conflicts committee or from holders of common units as described above and the board of directors of our general partner approves the resolution or course of action taken with respect to the conflict of interest, then it will be presumed that, in making its decision, the board of directors of our general partner acted in good faith, and in any proceeding brought by or on behalf of us or any of our unitholders, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption and proving that such decision was not in good faith. Unless the resolution of a conflict is specifically provided for in our partnership agreement, the board of directors of our general partner or the conflicts committee of the board of directors of our general partner may consider any factors they determine in good faith to consider when resolving a conflict. An independent third party is not required to evaluate the resolution. Under our partnership agreement, all determinations, other actions or failures to act by our general partner, the board of directors of our general partner or any committee thereof (including the conflicts committee) will be presumed to be "in good faith" and in any proceeding brought by or on behalf of us or any of our unitholders, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption and proving that such decision was not in good faith. Please read "Management—Committees of the Board of Directors—Conflicts Committee" for information about the conflicts committee of our general partner's board of directors.

Conflicts of interest could arise in the situations described below, among others:

Actions taken by our general partner may affect the amount of cash available to pay distributions to our unitholders or accelerate the right to convert subordinated units.

The amount of cash that is available for distribution to unitholders is affected by decisions of our general partner regarding such matters as:

- amount and timing of asset purchases and sales;
- cash expenditures;
- borrowings;
- entry into and repayment of current and future indebtedness;
- issuance of additional units; and
- the creation, reduction or increase of reserves in any quarter.

In addition, borrowings by us and our affiliates do not constitute a breach of any duty owed by our general partner to our unitholders, including borrowings that have the purpose or effect of:

- enabling our general partner or its affiliates to receive distributions on any subordinated units held by them or the incentive distribution rights; or
- hastening the expiration of the subordination period.

In addition, our general partner may use an amount, initially equal to $ million, which would not otherwise constitute operating surplus, in order to permit the payment of distributions on subordinated units and the incentive distribution rights. All of these actions may affect the amount of cash distributed to our unitholders and our general partner and may facilitate the conversion of subordinated units into common units. Please read "How We Make Distributions To Our Partners."

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For example, in the event we have not generated sufficient cash from our operations to pay the minimum quarterly distribution on our common units and our subordinated units, our partnership agreement permits us to borrow funds, which would enable us to make such distribution on all outstanding units. Please read "How We Make Distributions To Our Partners—Operating Surplus and Capital Surplus—Operating Surplus."

The directors and officers of our sponsor have a fiduciary duty to make decisions in the best interests of the owners of our sponsor, which may be contrary to our interests.

The officers and certain directors of our general partner have fiduciary duties to our sponsor that may cause them to pursue business strategies that disproportionately benefit our sponsor or which otherwise are not in our best interests.

Our general partner is allowed to take into account the interests of parties other than us, such as our sponsor, in exercising certain rights under our partnership agreement.

Our partnership agreement contains provisions that replace the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its call right, its voting rights with respect to any units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation or amendment of the partnership agreement.

Our partnership agreement restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty.

In addition to the provisions described above, our partnership agreement contains provisions that restrict the remedies available to our unitholders for actions that might otherwise constitute breaches of fiduciary duty. For example, our partnership agreement provides that:

- our general partner will not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith, meaning it believed that the decision was not adverse to the interest of the partnership, and, with respect to criminal conduct, did not act with the knowledge that its conduct was unlawful;

- our general partner and its officers and directors will not be liable for monetary damages or otherwise to us or our limited partners for any losses sustained or liabilities incurred as a result of the general partner's, officer's or director's determinations, acts or omissions in their capacities as general partner, officers or directors, unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that such losses or liabilities were the result of the conduct of our general partner or such officer or director engaged in by it in bad faith or, with respect to any criminal conduct, with the knowledge that its conduct was unlawful; and

- in resolving conflicts of interest, it will be presumed that in making its decision our general partner, the board of directors of our general partner or the conflicts committee of the board of directors of our general partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption and proving that such decision was not in good faith.

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By purchasing a common unit, the purchaser agrees to be bound by the provisions in our partnership agreement, including the provisions discussed above. Please read "—Fiduciary Duties."

Common unitholders have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us, on the one hand, and our general partner and its affiliates, on the other, will not grant to the unitholders, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

Contracts between us, on the one hand, and our general partner and its affiliates, on the other, are not and will not be the result of arm's-length negotiations.

Neither our partnership agreement nor any of the other agreements, contracts and arrangements between us and our general partner and its affiliates are or will be the result of arm's-length negotiations. Our general partner will determine, in good faith, the terms of any of such future transactions.

Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

Under our partnership agreement, our general partner has full power and authority to do all things, other than those items that require unitholder approval, necessary or appropriate to conduct our business, including the following actions:

- expending, lending, or borrowing money, assuming, guaranteeing, or otherwise contracting for, indebtedness and other liabilities, issuing evidences of indebtedness, including indebtedness that is convertible into our equity interests, and incurring any other obligations;
- making tax, regulatory and other filings, or rendering periodic or other reports to governmental or other agencies having jurisdiction over our business or assets;
- acquiring, disposing, mortgaging, pledging, encumbering, hypothecating, or exchanging our assets or merging or otherwise combining us with or into another person;
- negotiating, executing and performing contracts, conveyance or other instruments;
- distributing cash or cash equivalents;
- selecting, employing or dismissing employees, agents, outside attorneys, accountants, consultants and contractors and determining their compensation and other terms of employment or hiring;
- maintaining insurance for our benefit;
- forming, acquiring an interest in, and contributing property and loaning money to, any partnerships, joint ventures, corporations, limited liability companies or other entity (including corporations, firms, trusts and unincorporated organizations);
- controlling all matters affecting our rights and obligations, including bringing and defending actions at law or in equity or otherwise litigating, arbitrating or mediating, and incurring legal expense and settling claims and litigation;
- indemnifying any person against liabilities and contingencies to the extent permitted by law;
- purchasing, selling or otherwise acquiring or disposing of our partnership interests, or issuing options, rights, warrants, appreciation rights, tracking, profit and phantom interests and other derivative interests relating to, convertible into or exchangeable for our partnership interests; and

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- entering into agreements with any of its affiliates, including to render services to us or to itself in the discharge of its duties as our general partner.

Please read "The Partnership Agreement—Voting Rights" for information regarding the voting rights of unitholders.

Common units are subject to our general partner's call right.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at the price calculated in accordance with our partnership agreement. Please read "Risk Factors—Risks Inherent in an Investment in Us—Our general partner has a call right that may require unitholders to sell their common units at an undesirable time or price" and "The Partnership Agreement —Limited Call Right."

We may choose to not retain separate counsel for ourselves or for the holders of common units.

The attorneys, independent accountants and others who perform services for us have been retained by our general partner. Attorneys, independent accountants and others who perform services for us are selected by our general partner or the conflicts committee of the board of directors of our general partner and may perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the conflict committee in the event of a conflict of interest between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict, although we may choose not to do so.

Our general partner's affiliates may compete with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us.

Our partnership agreement provides that our general partner will be restricted from engaging in any business activities other than acting as our general partner, engaging in activities incidental to its ownership interest in us and providing management, advisory, and administrative services to its affiliates or to other persons. However, affiliates of our general partner, including our sponsor, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. In addition, our sponsor may compete with us for investment opportunities and may own an interest in entities that compete with us. Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers and directors and our sponsor. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us.

The holder or holders of our IDRs may elect to cause us to issue common units to it in connection with a resetting of target distribution levels related to the IDRs without the approval of the conflicts committee of our general partner's board of directors or the holders of our common units. This could result in lower distributions to holders of our common units.

The holder or holders of a majority of our incentive distribution rights (initially our general partner) have the right, at any time when there are no subordinated units outstanding and we have made cash distributions in excess of the highest then-applicable target distribution for each of the prior

four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our cash distribution levels at the time of the exercise of the reset election. Following a reset election, the reset minimum quarterly distribution will be calculated and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per unit without such conversion. However, our general partner may transfer the incentive distribution rights at any time. It is possible that our general partner or a transferee could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when the holders of the incentive distribution rights expect that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, the holders of the incentive distribution rights may be experiencing, or may expect to experience, declines in the cash distributions it receives related to the incentive distribution rights and may therefore desire to be issued our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that they would have otherwise received had we not issued new common units to the holders of the incentive distribution rights in connection with resetting the target distribution levels. Please read "How We Make Distributions To Our Partners—Incentive Distribution Rights—Incentive Distribution Right Holders' Right to Reset Incentive Distribution Levels."

Fiduciary Duties

Duties owed to unitholders by our general partner are prescribed by law and in our partnership agreement. The Delaware Act provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the fiduciary duties otherwise owed by the general partner to limited partners and the partnership.

Our partnership agreement contains various provisions that eliminate and replace the fiduciary duties that might otherwise be owed by our general partner. We have adopted these provisions to allow our general partner or its affiliates to engage in transactions with us that otherwise might be prohibited by state law fiduciary standards and to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. We believe this is appropriate and necessary because the board of directors of our general partner has a duty to manage our partnership in good faith and a duty to manage our general partner in a manner beneficial to its owner. Without these modifications, our general partner's ability to make decisions involving conflicts of interest would be restricted. Replacing the fiduciary duty standards in this manner benefits our general partner by enabling it to take into consideration all parties involved in the proposed action. Replacing the fiduciary duty standards also strengthens the ability of our general partner to attract and retain experienced and capable directors. Replacing the fiduciary duty standards represents a detriment to our public unitholders because it restricts the remedies available to our public unitholders for actions that, without those limitations, might constitute breaches of fiduciary duty, as described below, and permits our general partner to take into account the interests of third parties in addition to our interests when resolving conflicts of interests.

The following is a summary of the fiduciary duties imposed on general partners of a limited partnership by the Delaware Act in the absence of partnership agreement provisions to the contrary, the contractual duties of our general partner contained in our partnership agreement that replace the

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fiduciary duties that would otherwise be imposed by Delaware laws on our general partner and the rights and remedies of our unitholders with respect to these contractual duties:

State law fiduciary duty standards	Fiduciary duties are generally considered to include an obligation to act in good faith and with due care and loyalty. The duty of care, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner to act for the partnership in the same manner as a prudent person would act on his own behalf. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally require that any action taken or transaction engaged in be entirely fair to the partnership.
Partnership agreement modified standards	Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues as to compliance with fiduciary duties or applicable law. For example, our partnership agreement provides that when our general partner is acting in its capacity as our general partner, as opposed to in its individual capacity, it must act in "good faith" meaning that it believed its actions or omissions were not adverse to the interest of the partnership, and will not be subject to any higher standard under applicable law. In addition, when our general partner is acting in its individual capacity, as opposed to in its capacity as our general partner, it may act without any fiduciary obligation to us or the unitholders whatsoever. These contractual standards replace the obligations to which our general partner would otherwise be held. In making decisions, other than one where our general partner is permitted to act in its sole discretion, it will be presumed that in making its decision our general partner, the board of directors of our general partner or the conflicts committee of the board of directors of our general partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption and proving that such decision was not in good faith.

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Rights and remedies of unitholders	The Delaware Act generally provides that a limited partner may institute legal action on behalf of the partnership to recover damages from a third party where a general partner has refused to institute the action or where an effort to cause a general partner to do so is not likely to succeed. These actions include actions against a general partner for breach of its duties or of the partnership agreement. In addition, the statutory or case law of some jurisdictions may permit a limited partner to institute legal action on behalf of himself and all other similarly situated limited partners to recover damages from a general partner for violations of its fiduciary duties to the limited partners.

By purchasing our common units, the purchaser agrees to be bound by the provisions in our partnership agreement, including the provisions discussed above. This is in accordance with the policy of the Delaware Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner to sign a partnership agreement does not render the partnership agreement unenforceable against that person.

Under our partnership agreement, we must indemnify our general partner and its officers, directors, managers and certain other specified persons, to the fullest extent permitted by law, against liabilities, costs and expenses incurred by our general partner or these other persons. We must provide this indemnification unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that such losses or liabilities were the result of the conduct of our general partner or such officer or director engaged in by it in bad faith or, with respect to any criminal conduct, with the knowledge that its conduct was unlawful. Thus, our general partner could be indemnified for its negligent acts if it meets the requirements set forth above. To the extent these provisions purport to include indemnification for liabilities arising under the Securities Act in the opinion of the SEC, such indemnification is contrary to public policy and, therefore, unenforceable. Please read "The Partnership Agreement —Indemnification."

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DESCRIPTION OF THE COMMON UNITS

The Units

The common units and the subordinated units are separate classes of limited partner interests in us. The holders of units are entitled to participate in partnership distributions and exercise the rights or privileges available to limited partners under our partnership agreement. For a description of the relative rights and preferences of holders of common units and subordinated units in and to partnership distributions, please read this section and "How We Make Distributions To Our Partners." For a description of other rights and privileges of limited partners under our partnership agreement, including voting rights, please read "The Partnership Agreement."

Restrictions on Ownership of Common Units

In order to comply with certain U.S. laws relating to the ownership of interests in mineral leases on federal lands, we have adopted requirements regarding our owners. Our partnership agreement requires that a transferee of common units properly complete and deliver to us a transfer application containing a certification as to a number of matters, including the status of the transferee, or all its owners, as being an Eligible Holder (as defined below under "—Transfer of Common Units"). If a transferee or a common unitholder, as the case may be, is not an Eligible Holder, the transferee or common unitholder may not have any right to receive any distributions or allocations of income or loss on its common units or to vote its common units on any matter, and we have the right to redeem such common units at a price that is equal to the then-current market price of such common units. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner. Please read "—Transfer of Common Units" below and "The Partnership Agreement—Non-Eligible Holders; Redemption."

Transfer Agent and Registrar

Duties

American Stock Transfer & Trust Company, LLC will serve as the registrar and transfer agent for the common units. We will pay all fees charged by the transfer agent for transfers of common units except the following, which must be paid by our unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a holder of a common unit; and
- other similar fees or charges.

There will be no charge to our unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their stockholders, directors, officers and employees against all claims and losses that may arise out of acts performed or omitted for its activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

Resignation or Removal

The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor is appointed or has not accepted its appointment within 30 days of the resignation or removal, our general partner may act as the transfer agent and registrar until a successor is appointed.

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Transfer of Common Units

Upon the transfer of a common unit in accordance with our partnership agreement, the transferee of the common unit shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Each transferee:

- automatically becomes bound by the terms and conditions of our partnership agreement
- represents that the transferee has the capacity, power and authority to enter into our partnership agreement;
- makes the consents, acknowledgements and waivers contained in our partnership agreement, such as the approval of all transactions and agreements that we are entering into in connection with our formation and this offering; and
- certifies that the transferee is an Eligible Holder.

As used in this prospectus, an Eligible Holder means a person or entity qualified to hold an interest in mineral leases on federal lands. As of the date hereof, an Eligible Holder means: (1) a citizen of the United States; (2) a corporation organized under the laws of the United States or of any state thereof; or (3) an association of U.S. citizens, such as a partnership or limited liability company, organized under the laws of the United States or of any state thereof, but only if such association does not have any direct or indirect foreign ownership, other than foreign ownership of stock in a parent corporation organized under the laws of the United States or of any state thereof. For the avoidance of doubt, onshore mineral leases or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding or control in a corporation organized under the laws of the United States or of any state thereof and only for so long as the alien is not from a country that the U.S. federal government regards as denying similar privileges to citizens or corporations of the United States.

Our general partner will cause any transfers to be recorded on our books and records from time to time (or shall cause the transfer agent to do so, as applicable).

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and any transfers are subject to the laws governing the transfer of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a substituted limited partner in our partnership for the transferred common units.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the common unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

Listing

We intend to apply to list our common units on the NYSE under the symbol "BRLP."

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THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement, which we will adopt in connection with the closing of this offering. The form of our partnership agreement is included in this prospectus as Appendix A. We will provide investors and prospective investors with a copy of our partnership agreement, when available, upon request at no charge.

We summarize the following provisions of our partnership agreement elsewhere in this prospectus:

- with regard to distributions of cash available for distribution, please read "How We Make Distributions To Our Partners";
- with regard to the duties of, and standard of care applicable to, our general partner, please read "Conflicts of Interest and Fiduciary Duties";
- with regard to the transfer of common units, please read "Description of the Common Units—Transfer of Common Units"; and
- with regard to allocations of taxable income and taxable loss, please read "Material U.S. Federal Income Tax Consequences."

Organization and Duration

We were organized in January 2015 and will have a perpetual existence unless terminated pursuant to the terms of our partnership agreement.

Purpose

Our purpose, as set forth in our partnership agreement, is limited to any business activity that is approved by our general partner and that lawfully may be conducted by a limited partnership organized under Delaware law; provided that our general partner shall not cause us to take any action that the general partner determines would be reasonably likely to cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes.

Although our general partner has the ability to cause us and our subsidiaries to engage in activities other than the business of mining and transporting coal, our general partner may decline to do so in its sole discretion. Our general partner is generally authorized to perform all acts it determines to be necessary or appropriate to carry out our purposes and to conduct our business.

Cash Distributions

Our partnership agreement does not require us to pay distributions at any time or in any amount. Instead, the board of directors of our general partner will adopt a cash distribution policy to be effective as of the closing of this offering that will set forth our general partner's intention with respect to the distributions to be made to unitholders.

Our partnership agreement specifies the manner in which we will make cash distributions to holders of our common units and other partnership securities, as well as to our general partner in respect of its incentive distribution rights. For a description of these cash distribution provisions, please read "How We Make Distributions To Our Partners."

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described below under "—Limited Liability."

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Voting Rights

The following is a summary of the unitholder vote required for approval of the matters specified below. Matters that call for the approval of a "unit majority" require:

- during the subordination period, the approval of a majority of the common units, excluding those common units whose vote is controlled by our general partner or its affiliates, and a majority of the subordinated units, voting as separate classes; and
- after the subordination period, the approval of a majority of the common units.

In voting their common and subordinated units, our general partner and its affiliates will have no duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interests of us or the limited partners.

The incentive distribution rights may be entitled to vote in certain circumstances.

Issuance of additional units	No approval right.
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority. Please read "—Amendment of the Partnership Agreement."
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority in certain circumstances. Please read "—Merger, Consolidation, Conversion, Sale or Other Disposition of Assets."
Dissolution of our partnership	Unit majority. Please read "—Dissolution."
Continuation of our business upon dissolution	Unit majority. Please read "—Dissolution."
Withdrawal of our general partner	Under most circumstances, the approval of a majority of the common units, excluding common units held by our general partner and its affiliates, is required for the withdrawal of our general partner prior to , 2025 in a manner that would cause a dissolution of our partnership. Please read "—Withdrawal or Removal of Our General Partner."
Removal of our general partner	Not less than $66^{2}/_{3}$% of the outstanding units, voting as a single class, including units held by our general partner and its affiliates. In addition, any vote to remove our general partner during the subordination period must provide for the election of a successor general partner by the holders of a majority of the common units and a majority of the subordinated units, voting as separate classes. Please read "—Withdrawal or Removal of Our General Partner."
Transfer of our general partner interest	No approval right. Please read "—Transfer of General Partner Interest."

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Transfer of incentive distribution rights	No approval right. Please read "—Transfer of Subordinated Units and Incentive Distribution Rights."
Transfer of ownership interests in our general partner	No approval right. Please read "—Transfer of Ownership Interests in the General Partner."

If any person or group other than our general partner and its affiliates acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from our general partner or its affiliates and any transferees of that person or group approved by our general partner or to any person or group who acquires the units with the specific prior approval of our general partner.

Applicable Law; Forum, Venue and Jurisdiction

Our partnership agreement is governed by Delaware law. Our partnership agreement requires that any claims, suits, actions or proceedings:

- arising out of or relating in any way to the partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of the partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us);
- brought in a derivative manner on our behalf;
- asserting a claim of breach of a duty owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners;
- asserting a claim arising pursuant to any provision of the Delaware Act; or
- asserting a claim governed by the internal affairs doctrine,

shall be exclusively brought in the Court of Chancery of the State of Delaware, (or, if such court does not have subject matter jurisdiction thereof, any other court located in the State of Delaware with subject matter jurisdiction), regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims. By purchasing a common unit, a limited partner is irrevocably consenting to these limitations and provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other court) in connection with any such claims, suits, actions or proceedings.

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that he otherwise acts in conformity with the provisions of the partnership agreement, his liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital he is obligated to contribute to us for his common units plus his share of any undistributed profits and assets. However, if it were determined that the right, or exercise of the right, by the limited partners as a group:

- to remove or replace our general partner;
- to approve some amendments to our partnership agreement; or
- to take other action under our partnership agreement;

constituted "participation in the control" of our business for the purposes of the Delaware Act, then the limited partners could be held personally liable for our obligations under the laws of Delaware, to

the same extent as our general partner. This liability would extend to persons who transact business with us under the reasonable belief that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years.

Following the completion of this offering, we expect that our subsidiaries will conduct business in Utah, Kentucky and Colorado and we may have subsidiaries that conduct business in other states or countries in the future. Maintenance of our limited liability as owner of our operating subsidiaries may require compliance with legal requirements in the jurisdictions in which the operating subsidiaries conduct business, including qualifying our subsidiaries to do business there.

Limitations on the liability of members or limited partners for the obligations of a limited liability company or limited partnership have not been clearly established in many jurisdictions. If, by virtue of our ownership interest in our subsidiaries or otherwise, it were determined that we were conducting business in any jurisdiction without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by the limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted "participation in the control" of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of the limited partners.

Issuance of Additional Interests

Our partnership agreement authorizes us to issue an unlimited number of additional partnership interests for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units, subordinated units or other partnership interests. Holders of any additional common units we issue will be entitled to share equally with the then-existing common unitholders in our distributions. In addition, the issuance of additional common units or other partnership interests may dilute the value of the interests of the then-existing common unitholders in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership interests that, as determined by our general partner, may have rights to distributions or special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit our subsidiaries from issuing equity interests, which may effectively rank senior to the common units.

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Our general partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units, subordinated units or other partnership interests whenever, and on the same terms that, we issue partnership interests to persons other than our general partner and its affiliates, to the extent necessary to maintain the percentage interest of our general partner and its affiliates, including such interest represented by common and subordinated units, that existed immediately prior to each issuance. The common unitholders will not have preemptive rights under our partnership agreement to acquire additional common units or other partnership interests.

Amendment of the Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interests of us or the limited partners. In order to adopt a proposed amendment, other than the amendments described below, our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or to call a meeting of the limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or
- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld in its sole discretion.

The provision of our partnership agreement preventing the amendments having the effects described in the clauses above can be amended upon the approval of the holders of at least 90.0% of the outstanding units, voting as a single class (including units owned by our general partner and its affiliates). Upon completion of the offering, an affiliate of our general partner will own approximately % of our outstanding common and subordinated units.

No Unitholder Approval

Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner to reflect:

- a change in our name, the location of our principal place of business, our registered agent or our registered office;
- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;
- a change that our general partner determines to be necessary or appropriate to qualify or continue our qualification as a limited partnership or other entity in which the limited partners have limited liability under the laws of any state or to ensure that neither we nor any of our subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes (to the extent not already so treated or taxed);
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or its directors, officers, agents or trustees from in any manner being subjected to the

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provisions of the Investment Company Act of 1940, the Investment Advisers Act of 1940 or "plan asset" regulations adopted under ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed;

- an amendment that our general partner determines to be necessary or appropriate in connection with the creation, authorization or issuance of additional partnership interests or the right to acquire partnership interests;
- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;
- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;
- any amendment that our general partner determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership, or other entity, as otherwise permitted by our partnership agreement;
- a change in our fiscal year or taxable year and related changes;
- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; or
- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our partnership agreement, without the approval of any limited partner, if our general partner determines that those amendments:

- do not adversely affect the limited partners, considered as a whole, or any particular class of limited partners in any material respect;
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary or appropriate to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed for trading;
- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement; or
- are required to effect the intent expressed in this prospectus or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Unitholder Approval

Any amendment that our general partner determines adversely affects in any material respect one or more particular classes of limited partners, and is not permitted to be adopted by our general partner without limited partner approval, will require the approval of at least a majority of the class or classes so affected, but no vote will be required by any class or classes of limited partners that our general partner determines are not adversely affected in any material respect. Any such amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected. Any such amendment that would reduce the voting percentage required to take any action other than to remove the general partner or call a meeting of unitholders is required to be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced. Any such amendment that would increase the percentage of units required to remove the general partner or call a meeting of unitholders must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the percentage sought to be increased.

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For amendments of the type not requiring unitholder approval, our general partner will not be required to obtain an opinion of counsel that an amendment will neither result in a loss of limited liability to the limited partners nor result in our being treated as a taxable entity for federal income tax purposes in connection with any of the amendments. No other amendments to our partnership agreement will become effective without the approval of holders of at least 90% of the outstanding units, voting as a single class, unless we first obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any of our limited partners.

Merger, Consolidation, Conversion, Sale or Other Disposition of Assets

A merger, consolidation or conversion of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger, consolidation or conversion and may decline to do so free of any duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interest of us or the limited partners.

In addition, our partnership agreement generally prohibits our general partner, without the prior approval of the holders of a unit majority, from causing us to sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without such approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without such approval. Finally, our general partner may consummate any merger without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction would not result in a material amendment to the partnership agreement (other than an amendment that the general partner could adopt without the consent of other partners), each of our units will be an identical unit of our partnership following the transaction and the partnership interests to be issued do not exceed 20% of our outstanding partnership interests (other than incentive distribution rights) immediately prior to the transaction.

If the conditions specified in our partnership agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity, if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, we have received an opinion of counsel regarding limited liability and tax matters and the governing instruments of the new entity provide the limited partners and our general partner with the same rights and obligations as contained in our partnership agreement. Our unitholders are not entitled to dissenters' rights of appraisal under our partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Dissolution

We will continue as a limited partnership until dissolved under our partnership agreement. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;
- there being no limited partners, unless we are continued without dissolution in accordance with applicable Delaware law;
- the entry of a decree of judicial dissolution of our partnership; or

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- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or its withdrawal or removal following the approval and admission of a successor.

Upon a dissolution under the last clause above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of units representing a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability under Delaware law of any limited partner; and

- neither our partnership nor any of our subsidiaries would be treated as an association taxable as a corporation or otherwise be taxable as an entity for federal income tax purposes upon the exercise of that right to continue (to the extent not already so treated or taxed).

Liquidation and Distribution of Proceeds

Upon our dissolution, unless our business is continued, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate, liquidate our assets and apply the proceeds of the liquidation as described in "How We Make Distributions To Our Partners—Distributions of Cash Upon Liquidation." The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of Our General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to , 2025 without obtaining the approval of the holders of at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates, and furnishing an opinion of counsel regarding limited liability and tax matters. On or after , 2025, our general partner may withdraw as general partner without first obtaining approval of any unitholder by giving 90 days' written notice, and that withdrawal will not constitute a violation of our partnership agreement. Notwithstanding the information above, our general partner may withdraw without unitholder approval upon 90 days' notice to the limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates, other than our general partner and its affiliates. In addition, our partnership agreement permits our general partner, in some instances, to sell or otherwise transfer all of its general partner interest in us without the approval of the unitholders. Please read "—Transfer of General Partner Interest."

Upon withdrawal of our general partner under any circumstances, other than as a result of a transfer by our general partner of all or a part of its general partner interest in us, the holders of a unit majority may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period after that withdrawal, the holders of a unit majority agree in writing to continue our business and to appoint a successor general partner. Please read "—Dissolution."

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than $66^{2}/_{3}$% of the outstanding units, voting together as a single class, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a

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successor general partner by the vote of the holders of a majority of the outstanding common units, voting as a class, and the outstanding subordinated units, voting as a class. The ownership of more than 33 1/3% of the outstanding units by our general partner and its affiliates gives them the ability to prevent our general partner's removal. At the closing of this offering, an affiliate of our general partner will own % of our outstanding limited partner units, including all of our subordinated units.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist:

- all subordinated units held by any person who did not, and whose affiliates did not, vote any units in favor of the removal of the general partner, will immediately and automatically convert into common units on a one-for-one basis; and
- if all of the subordinated units convert pursuant to the foregoing, all cumulative common unit arrearages on the common units will be extinguished and the subordination period will end.

In the event of the removal of our general partner under circumstances where cause exists or withdrawal of our general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the general partner interest and incentive distribution rights of the departing general partner and its affiliates for a cash payment equal to the fair market value of those interests. Under all other circumstances where our general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest and the incentive distribution rights of the departing general partner and its affiliates for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. Or, if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner's general partner interest and all its and its affiliates' incentive distribution rights will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred as a result of the termination of any employees employed for our benefit by the departing general partner or its affiliates.

Transfer of General Partner Interest

At any time, our general partner may transfer all or any of its general partner interest to another person without the approval of our common unitholders. As a condition of this transfer, the transferee must, among other things, assume the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement and furnish an opinion of counsel regarding limited liability and tax matters.

Transfer of Ownership Interests in the General Partner

At any time, the owner of our general partner may sell or transfer all or part of its ownership interests in our general partner to an affiliate or third party without the approval of our unitholders.

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Transfer of Subordinated Units and Incentive Distribution Rights

By transfer of subordinated units or incentive distribution rights in accordance with our partnership agreement, each transferee of subordinated units or incentive distribution rights will be admitted as a limited partner with respect to the subordinated units or incentive distribution rights transferred when such transfer and admission is reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;
- automatically becomes bound by the terms and conditions of our partnership agreement; and
- gives the consents, waivers and approvals contained in our partnership agreement, such as the approval of all transactions and agreements we are entering into in connection with our formation and this offering.

Our general partner will cause any transfers to be recorded on our books and records no less frequently than quarterly.

We may, at our discretion, treat the nominee holder of subordinated units or incentive distribution rights as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Subordinated units and incentive distribution rights are securities and any transfers are subject to the laws governing transfer of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a limited partner for the transferred subordinated units or incentive distribution rights.

Until a subordinated unit or incentive distribution right has been transferred on our books, we and the transfer agent may treat the record holder of the unit or right as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove Bowie GP, LLC as our general partner or from otherwise changing our management. Please read "—Withdrawal or Removal of Our General Partner" for a discussion of certain consequences of the removal of our general partner. If any person or group, other than our general partner and its affiliates, acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply in certain circumstances. Please read "—Meetings; Voting."

Limited Call Right

If at any time our general partner and its affiliates own more than 80% of the then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the limited partner interests of the class held by unaffiliated persons, as of a record date to be selected by our general partner, on at least 10, but not more than 60, days' notice. The purchase price in the event of this purchase is the greater of:

- the highest price paid by our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and

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- the average of the daily closing prices of the partnership securities of such class over the 20 trading days preceding the date that is three days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at an undesirable time or at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market. Please read "Material U.S. Federal Income Tax Consequences—Disposition of Units."

Non-Taxpaying Holders; Redemption

To avoid any adverse effect on the maximum applicable rates chargeable to customers by us or any of our future subsidiaries, or in order to reverse an adverse determination that has occurred regarding such maximum rate, our partnership agreement provides our general partner the power to amend our partnership agreement. If our general partner, with the advice of counsel, determines that our not being treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes, coupled with the tax status (or lack of proof thereof) of one or more of our limited partners (or their owners, to the extent relevant), has, or is reasonably likely to have, a material adverse effect on the maximum applicable rates chargeable to customers by our subsidiaries, then our general partner may adopt such amendments to our partnership agreement as it determines necessary or advisable to:

- obtain proof of the federal income tax status of our limited partners (and their owners, to the extent relevant); and

- permit us to redeem the units held by any person whose tax status has or is reasonably likely to have a material adverse effect on the maximum applicable rates or who fails to comply with the procedures instituted by our general partner to obtain proof of such person's federal income tax status. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

Non-Citizen Assignees; Redemption

If our general partner, with the advice of counsel, determines we are subject to federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner (or its owners, to the extent relevant), then our general partner may adopt such amendments to our partnership agreement as it determines necessary or advisable to:

- obtain proof of the nationality, citizenship or other related status of our limited partners (or their owners, to the extent relevant); and

- permit us to redeem the units held by any person whose nationality, citizenship or other related status creates substantial risk of cancellation or forfeiture of any property or who fails to comply with the procedures instituted by the general partner to obtain proof of the nationality, citizenship or other related status. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

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Non-Eligible Holders; Redemption

To comply with certain U.S. laws relating to the ownership of interests in mineral leases on federal lands, common unit transferees may be required to fill out a properly completed transfer application certifying, and our general partner, acting on our behalf, may at any time require each common unitholder to re-certify that the common unitholder is an Eligible Holder. As used herein, an Eligible Holder means a person or entity qualified to hold an interest in mineral leases on federal lands. As of the date hereof, Eligible Holder means: (1) a citizen of the United States; (2) a corporation organized under the laws of the United States or of any state thereof; or (3) an association of United States citizens, such as a partnership or limited liability company, organized under the laws of the United States or of any state thereof, but only if such association does not have any direct or indirect foreign ownership, other than foreign ownership of stock in a parent corporation organized under the laws of the United States or of any state thereof. For the avoidance of doubt, onshore mineral leases, or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding, or control in a corporation organized under the laws of the United States or of any state thereof and only for so long as the alien is not from a country that the United States federal government regards as denying similar privileges to citizens or corporations of the United States. This certification can be changed in any manner our general partner determines is necessary or appropriate to implement its original purpose.

If a common unit transferee or common unitholder, as the case may be:

- fails to furnish a transfer application containing the required certification;
- fails to furnish a re-certification containing the required certification within 30 days after request; or
- provides a false certification;

then, as the case may be, such transfer will, to the fullest extent permitted by law, be void or we will have the right to redeem the units held by the common unitholder. Further, the common units held by the common unitholder may not be entitled to any allocations of income or loss, distributions, or voting rights.

The purchase price will be paid in cash or delivery of a promissory note, as determined by our general partner. Any such promissory note will bear interest at the rate of 8% annually and be payable in three equal annual installments of principal and accrued interest, commencing one year after the redemption date.

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, record holders of units on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited.

Our general partner does not anticipate that any meeting of our unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called, represented in person or by proxy, will constitute a quorum, unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage. Our general partner

may postpone any meeting of unitholders one or more times for any reason by giving notice to the unitholders entitled to vote at such meeting. Our general partner may also adjourn any meeting of unitholders one or more times for any reason, including the absence of a quorum, without a vote of the unitholders.

Each record holder of a unit has a vote according to his percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please read "—Issuance of Additional Interests." However, if at any time any person or group, other than our general partner and its affiliates, or a direct or subsequently approved transferee of our general partner or its affiliates and purchasers specifically approved by our general partner, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise. Except as our partnership agreement otherwise provides, subordinated units will vote together with common units, as a single class. Units that are owned by Non-Eligible Holders will be voted by our general partner and our general partner will distribute the votes on those units in the same ratios as the votes of limited partners on other units are cast.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record common unitholders under our partnership agreement will be delivered to the record holder by us or by the transfer agent.

Voting Rights of Incentive Distribution Rights

If a majority of the incentive distribution rights are held by our general partner and its affiliates, the holders of the incentive distribution rights will have no right to vote in respect of such rights on any matter, unless otherwise required by law, and the holders of the incentive distribution rights, shall be deemed to have approved any matter approved by our general partner.

If less than a majority of the incentive distribution rights are held by our general partner and its affiliates, the incentive distribution rights will be entitled to vote on all matters submitted to a vote of unitholders, other than amendments and other matters that our general partner determines do not adversely affect the holders of the incentive distribution rights in any material respect. On any matter in which the holders of incentive distribution rights are entitled to vote, such holders will vote together with the subordinated units, prior to the end of the subordination period, or together with the common units, thereafter, in either case as a single class, and such incentive distribution rights shall be treated in all respects as subordinated units or common units, as applicable, when sending notices of a meeting of our limited partners to vote on any matter (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under our partnership agreement. The relative voting power of the holders of the incentive distribution rights and the subordinated units or common units, depending on which class the holders of incentive distribution rights are voting with, will be set in the same proportion as cumulative cash distributions, if any, in respect of the incentive distribution rights for the four consecutive quarters prior to the record date for the vote bears to the cumulative cash distributions in respect of such class of units for such four quarters.

Status as Limited Partner

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred

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when such transfer and admission are reflected in our books and records. Except as described under "—Limited Liability," the common units will be fully paid, and unitholders will not be required to make additional contributions.

Indemnification

Under our partnership agreement, in most circumstances, we will indemnify the following persons, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of our general partner or any departing general partner;
- any person who is or was a manager, managing member, general partner, director, officer, fiduciary or trustee of our partnership, our subsidiaries, our general partner, any departing general partner or any of their affiliates;
- any person who is or was serving as a manager, managing member, general partner, director, officer, employee, agent, fiduciary or trustee of another person owing a fiduciary duty to us or our subsidiaries;
- any person who controls our general partner or any departing general partner; and
- any person designated by our general partner.

Any indemnification under these provisions will only be out of our assets. Unless our general partner otherwise agrees, it will not be personally liable for, or have any obligation to contribute or lend funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our general partner may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our general partner is entitled to determine the expenses that are allocable to us.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. These books will be maintained for both tax and financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, our fiscal year is the calendar year.

We will furnish or make available to record holders of our common units, within 105 days after the close of each fiscal year, an annual report containing audited consolidated financial statements and a report on those consolidated financial statements by our independent public accountants. Except for our fourth quarter, we will also furnish or make available summary financial information within 50 days after the close of each quarter. We will be deemed to have made any such report available if we file such report with the SEC on EDGAR or make the report available on a publicly available website that we maintain.

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We will furnish each record holder with information reasonably required for federal and state tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to our unitholders will depend on their cooperation in supplying us with specific information. Every unitholder will receive information to assist him in determining his federal and state tax liability and in filing his federal and state income tax returns, regardless of whether he supplies us with the necessary information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each record holder; and
- copies of our partnership agreement, our certificate of limited partnership, related amendments and powers of attorney under which they have been executed.

Under our partnership agreement, however, each of our limited partners and other persons who acquire interests in our partnership interests, do not have rights to receive information from us or any of the persons we indemnify as described above under "—Indemnification" for the purpose of determining whether to pursue litigation or assist in pending litigation against us or those indemnified persons relating to our affairs, except pursuant to the applicable rules of discovery relating to the litigation commenced by the person seeking information.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner determines is not in our best interests or that we are required by law or by agreements with third parties to keep confidential. Our partnership agreement limits the rights to information that a limited partner would otherwise have under Delaware law.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units, subordinated units or other limited partner interests proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts.

In addition, in connection with this offering, we expect to enter into a registration rights agreement with our sponsor. Please read "Certain Relationships and Related Party Transactions—Agreements with Affiliates in Connection with the Transactions—Registration Rights Agreement."

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UNITS ELIGIBLE FOR FUTURE SALE

After the sale of the common units offered by this prospectus, our sponsor will hold an aggregate of common units and subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and some may convert earlier. The sale of these common and subordinated units could have an adverse impact on the price of the common units or on any trading market that may develop.

Our common units sold in this offering will generally be freely transferable without restriction or further registration under the Securities Act, except that any common units held by an "affiliate" of ours may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise. Rule 144 permits securities acquired by an affiliate of the issuer to be sold into the market in an amount that does not exceed, during any three-month period, the greater of:

- 1% of the total number of the securities outstanding; or
- the average weekly reported trading volume of our common units for the four weeks prior to the sale.

Sales under Rule 144 are also subject to specific manner of sale provisions, holding period requirements, notice requirements and the availability of current public information about us. A person who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned our common units for at least six months (provided we are in compliance with the current public information requirement), or one year (regardless of whether we are in compliance with the current public information requirement), would be entitled to sell those common units under Rule 144, subject only to the current public information requirement. After beneficially owning Rule 144 restricted units for at least one year, a person who is not deemed to have been an affiliate of ours at any time during the 90 days preceding a sale would be entitled to freely sell those common units without regard to the public information requirements, volume limitations, manner of sale provisions and notice requirements of Rule 144.

Our partnership agreement provides that we may issue an unlimited number of limited partner interests of any type at any time without a vote of the unitholders. Any issuance of additional common units or other limited partner interests would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect the cash distributions to and market price of, common units then outstanding. Please read "The Partnership Agreement—Issuance of Additional Interests."

Under our partnership agreement and the registration rights agreement that we expect to enter into, our sponsor will have the right to cause us to register under the Securities Act and applicable state securities laws the offer and sale of any units that it holds. Subject to the terms and conditions of the partnership agreement and the registration rights agreement, these registration rights allow our sponsor or its assignees holding any units to require registration of any of these units and to include any of these units in a registration by us of other units, including units offered by us or by any unitholder. Alternatively, we may be required to undertake a future public or private offering of common units and use the net proceeds from such offering to redeem an equal number of common units held by our sponsor. Our sponsor will continue to have these registration rights for two years following the withdrawal or removal of Bowie GP, LLC as our general partner. In connection with any registration of this kind, we will indemnify each unitholder participating in the registration and its officers, directors, and controlling persons from and against any liabilities under the Securities Act or any applicable state securities laws arising from the registration statement or prospectus. We will bear all costs and expenses incidental to any registration, excluding any underwriting discount. Except as

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described below, our sponsor may sell its units in private transactions at any time, subject to compliance with applicable laws.

The executive officers and directors of our general partner and our sponsor have agreed not to sell any common units they beneficially own for a period of 180 days from the date of this prospectus. Please read "Underwriting" for a description of these lock-up provisions.

Prior to the completion of this offering, we expect to adopt a new LTIP. If adopted, we intend to file a registration statement on Form S-8 under the Securities Act to register common units issuable under the LTIP. This registration statement on Form S-8 is expected to be filed following the effective date of the registration statement of which this prospectus is a part and will be effective upon filing. Accordingly, common units issued under the LTIP will be eligible for resale in the public market without restriction after the effective date of the Form S-8 registration statement, subject to applicable vesting requirements, Rule 144 limitations applicable to affiliates and the lock-up restrictions described above.

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MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES

This section summarizes the material federal income tax consequences that may be relevant to prospective unitholders and is based upon current provisions of the Internal Revenue Code of 1986, as amended (the "Code"), existing and proposed Treasury regulations thereunder (the "Treasury Regulations"), and current administrative rulings and court decisions, all of which are subject to change. Changes in these authorities may cause the federal income tax consequences to a prospective unitholder to vary substantially from those described below. Unless the context otherwise requires, references in this section to "we" or "us" are references to the partnership and its subsidiaries on and after the closing of this offering.

Legal conclusions contained in this section, unless otherwise noted, are the opinion of Vinson & Elkins L.L.P. and are based on the accuracy of representations made by us to them for this purpose. However, this section does not address all federal income tax matters that affect us or our unitholders and does not describe the application of the alternative minimum tax that may be applicable to certain unitholders. Furthermore, this section focuses on unitholders who are individual citizens or residents of the United States (for federal income tax purposes), who have the U.S. dollar as their functional currency and who hold units as capital assets (generally, property that is held for investment). This section has limited applicability to corporations, partnerships, (including entities treated as partnerships for federal income tax purposes), estates, trusts, non-resident aliens or other unitholders subject to specialized tax treatment, such as tax-exempt institutions, non-U.S. persons, IRAs, employee benefit plans, real estate investment trusts or mutual funds. ***Accordingly, we encourage each unitholder to consult the unitholder's own tax advisor in analyzing the federal, state, local and non-U.S. tax consequences particular to that unitholder resulting from ownership or disposition of units and potential changes in applicable tax laws.***

We are relying on opinions and advice of Vinson & Elkins L.L.P. with respect to the matters described herein. An opinion of counsel represents only that counsel’s best legal judgment and does not bind the IRS or a court. Accordingly, the opinions and statements made herein may not be sustained by a court if contested by the IRS. Any such contest of the matters described herein may materially adversely impact the market for units and the prices at which our units trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution. Furthermore, the tax consequences of an investment in us may be significantly modified by future legislative or administrative changes or court decisions, which may be retroactively applied.

For the reasons described below, Vinson & Elkins L.L.P. has not rendered an opinion with respect to the following federal income tax issues: (1) the treatment of a unitholder whose units are the subject of a securities loan (e.g., a loan to a short seller to cover a short sale of units) (please read "—Tax Consequences of Unit Ownership—Treatment of Securities Loans"); (2) whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations (please read "—Disposition of Units—Allocations Between Transferors and Transferees"); and (3) whether our method for allocating excess depletion deductions and taking into account Section 743 adjustments is sustainable in certain cases (please read "—Tax Consequences of Unit Ownership—Section 754 Election" and "—Disposition of Units—Uniformity of Units").

Taxation of the Partnership

Partnership Status

We expect to be treated as a partnership for U.S. federal income tax purposes and, therefore, generally will not be liable for entity-level federal income taxes. Instead, as described below, each of our unitholders will take into account its respective share of our items of income, gain, loss and deduction in computing its federal income tax liability as if the unitholder had earned such income directly, even if we make no cash distributions to the unitholder. Distributions we make to a unitholder

generally will not give rise to income or gain taxable to such unitholder, unless the amount of cash distributed exceeds the unitholder's adjusted tax basis in its units.

Section 7704 of the Code generally provides that publicly traded partnerships will be treated as corporations for federal income tax purposes. However, if 90% or more of a partnership's gross income for every taxable year it is publicly traded consists of "qualifying income," the partnership may continue to be treated as a partnership for federal income tax purposes (the "Qualifying Income Exception"). Qualifying income includes income and gains derived from the mining, transportation and marketing of minerals and natural resources, such as coal. Other types of qualifying income include interest (other than from a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. We estimate that less than 2.0% of our current gross income is not qualifying income; however, this estimate could change from time to time.

Based upon factual representations made by us and our general partner, Vinson & Elkins L.L.P. is of the opinion that we will be treated as a partnership and each of our limited liability company subsidiaries will be disregarded as entities separate from us for federal income tax purposes. The representations made by us and by our general partner upon which Vinson & Elkins L.L.P. has relied in rendering its opinion include, without limitation:

(a) neither we nor any of our operating subsidiaries has elected to be treated as a corporation for federal income tax purposes; and

(b) for each taxable year, more than 90% of our gross income will be income of a character that Vinson & Elkins L.L.P. has opined is "qualifying income" within the meaning of Section 7704(d) of the Code.

We believe that these representations are true and will be true in the future.

If we fail to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery (in which case the IRS may also require us to make adjustments with respect to our unitholders or pay other amounts), we will be treated as transferring all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation and then as distributing that stock to our unitholders in liquidation. This deemed contribution and liquidation should not result in the recognition of taxable income by our unitholders or us so long as our liabilities do not exceed the tax basis of our assets. Thereafter, we would be treated as an association taxable as a corporation for federal income tax purposes.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. From time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. For example, the 2015 Budget Proposal would eliminate the Qualifying Income Exception upon which we rely for our treatment as a partnership for U.S. federal income tax purposes for partnerships with qualifying income from fossil fuels, including coal beginning in 2021. Further, the Treasury Department and the IRS issued proposed Regulations interpreting the scope of the Qualifying Income Exception on May 5, 2015 (the "Proposed Regulations"). We believe the income that we treat as qualifying income satisfies the requirements for qualifying income under the Proposed Regulations. However, the Proposed Regulations could be changed before they are finalized and could take a position that is contrary to our interpretation of Section 7704 of the Code. We are unable to predict whether these changes, or other proposals, will ultimately be enacted. However, it is possible that a change in law could affect us and may be applied retroactively. Any such changes could negatively impact the value of an investment in our units.

If for any reason we are taxable as a corporation in any taxable year, our items of income, gain, loss and deduction would be taken into account by us in determining the amount of our liability for

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federal income tax, rather than being passed through to our unitholders. Our taxation as a corporation would materially reduce the cash available for distribution to unitholders and thus would likely substantially reduce the value of our units. Any distribution made to a unitholder at a time we are treated as a corporation would be (i) a taxable dividend to the extent of our current or accumulated earnings and profits, then (ii) a nontaxable return of capital to the extent of the unitholder's tax basis in its units, and thereafter (iii) taxable capital gain.

The remainder of this discussion is based on the opinion of Vinson & Elkins L.L.P. that we will be treated as a partnership for federal income tax purposes.

Tax Consequences of Unit Ownership

Limited Partner Status

Unitholders who are admitted as limited partners of the partnership, as well as unitholders whose units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of units, will be treated as partners of the partnership for federal income tax purposes. For a discussion related to the risks of losing partner status as a result of securities loans, please read "—Treatment of Securities Loans." Unitholders who are not treated as partners in us as described above are urged to consult their own tax advisors with respect to the tax consequences applicable to them under the circumstances.

Flow-Through of Taxable Income

Subject to the discussion below under "—Entity-Level Collections of Unitholder Taxes" with respect to payments we may be required to make on behalf of our unitholders, we will not pay any federal income tax. Rather, each unitholder will be required to report on its federal income tax return each year its share of our income, gains, losses and deductions for our taxable year or years ending with or within its taxable year. Consequently, we may allocate income to a unitholder even if that unitholder has not received a cash distribution.

Ratio of Taxable Income to Distributions

We estimate that a purchaser of common units in this offering who owns those common units from the date of closing of this offering through the record date for distributions for the period ending December 31, , will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be less than % of the cash distributed with respect to that period. Thereafter, we anticipate that the ratio of taxable income to cash distributions to the common unitholders will increase. These estimates are based upon the assumption that earnings from operations will approximate the amount required to make the minimum quarterly distribution on all units and other assumptions with respect to capital expenditures, cash flow, net working capital and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond our control. Further, the estimates are based on current tax law and tax reporting positions that we will adopt and with which the IRS could disagree. Accordingly, we cannot assure you that these estimates will prove to be correct. The actual ratio of taxable income to cash distributions could be higher or lower than expected, and any differences could be material and could materially affect the value of the common units. For example, the ratio of taxable income to cash distributions to a purchaser of common units in this offering will be higher, and perhaps substantially higher, than our estimate with respect to the period described above if:

- the earnings from operations exceeds the amount required to make minimum quarterly distributions on all common units, yet we only distribute the minimum quarterly distributions on all units; or

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- we make a future offering of common units and use the proceeds of the offering in a manner that does not produce substantial additional deductions during the period described above, such as to repay indebtedness outstanding at the time of this offering or to acquire property that is not eligible for depreciation, depletion or amortization for federal income tax purposes or that is depreciable, depletable or amortizable at a rate significantly slower than the rate applicable to our assets at the time of this offering; or

- legislation is passed that would limit or repeal certain federal income tax preferences currently available with respect to coal exploration and development (please read "—Tax Treatment of Operations—Recent Legislative Developments").

Basis of Units

A unitholder's tax basis in its units initially will be the amount paid for those units plus the unitholder's share of our liabilities. That basis generally will be (i) increased by the unitholder's share of our income and any increases in such unitholder's share of our liabilities, and (ii) decreased, but not below zero, by the amount of all distributions, the unitholder's share of our losses, and any decreases in its share of our liabilities. The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all of those interests.

Treatment of Distributions

Distributions made by us to a unitholder generally will not be taxable to the unitholder, unless such distributions exceed the unitholder's tax basis in its units, in which case the unitholder generally will recognize gain taxable in the manner described below under "—Disposition of Units."

Any reduction in a unitholder's share of our "liabilities" will be treated as a distribution by us of cash to that unitholder. A decrease in a unitholder's percentage interest in us because of our issuance of additional units may decrease the unitholder's share of our liabilities. For purposes of the foregoing, a unitholder's share of our nonrecourse liabilities (liabilities for which no partner bears the economic risk of loss) generally will be based upon that unitholder's share of the unrealized appreciation (or depreciation) in our assets, to the extent thereof, with any excess liabilities allocated based on the unitholder's share of our profits. Please read "—Disposition of Units."

A non-pro rata distribution of money or property (including a deemed distribution as a result of the reallocation of our liabilities described above) may cause a unitholder to recognize ordinary income, if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation and depletion recapture and substantially appreciated "inventory items," both as defined in Section 751 of the Code ("Section 751 Assets"). To the extent of such reduction, the unitholder would be deemed to receive its proportionate share of the Section 751 Assets and exchange such assets with us in return for a portion of the non-pro rata distribution. This deemed exchange generally will result in the unitholder's recognition of ordinary income in an amount equal to the excess of (1) the non-pro rata portion of that distribution over (2) the unitholder's tax basis (generally zero) in the Section 751 Assets deemed to be relinquished in the exchange.

Limitations on Deductibility of Losses

A unitholder may not be entitled to deduct the full amount of loss we allocate to it because its share of our losses will be limited to the lesser of (i) the unitholder's tax basis in its units, and (ii) in the case of a unitholder that is an individual, estate, trust or certain types of closely-held corporations, the amount for which the unitholder is considered to be "at risk" with respect to our activities. In general, a unitholder will be at risk to the extent of its tax basis in its units, reduced by (1) any portion of that basis attributable to the unitholder's share of our liabilities, (2) any portion of that basis representing amounts otherwise protected against loss because of a guarantee, stop loss agreement or

similar arrangement and (3) any amount of money the unitholder borrows to acquire or hold its units, if the lender of those borrowed funds owns an interest in us, is related to another unitholder or can look only to the units for repayment. A unitholder subject to the at risk limitation must recapture losses deducted in previous years to the extent that distributions (including distributions deemed to result from a reduction in a unitholder's share of nonrecourse liabilities) cause the unitholder's at risk amount to be less than zero at the end of any taxable year.

Losses disallowed to a unitholder or recaptured as a result of the basis or at risk limitations will carry forward and will be allowable as a deduction in a later year to the extent that the unitholder's tax basis or at risk amount, whichever is the limiting factor, is subsequently increased. Upon a taxable disposition of units, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but not losses suspended by the basis limitation. Any loss previously suspended by the at risk limitation in excess of that gain can no longer be used, and will not be available to offset a unitholder's salary or active business income.

In addition to the basis and at risk limitations, a passive activity loss limitation generally limits the deductibility of losses incurred by individuals, estates, trusts, some closely-held corporations and personal service corporations from "passive activities" (generally, trade or business activities in which the taxpayer does not materially participate). The passive loss limitations are applied separately with respect to each publicly traded partnership. Consequently, any passive losses we generate will be available to offset only passive income generated by us. Passive losses that exceed a unitholder's share of passive income we generate may be deducted in full when the unitholder disposes of all of its units in a fully taxable transaction with an unrelated party. The passive loss rules generally are applied after other applicable limitations on deductions, including the at risk and basis limitations.

Limitations on Interest Deductions

The deductibility of a non-corporate taxpayer's "investment interest expense" generally is limited to the amount of that taxpayer's "net investment income." Investment interest expense includes:

- interest on indebtedness allocable to property held for investment;
- interest expense allocated against portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent allocable against portfolio income.

The computation of a unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses other than interest directly connected with the production of investment income. Net investment income generally does not include qualified dividend income or gains attributable to the disposition of property held for investment. A unitholder's share of a publicly traded partnership's portfolio income and, according to the IRS, net passive income will be treated as investment income for purposes of the investment interest expense limitation.

Entity-Level Collections of Unitholder Taxes

If we are required or elect under applicable law to pay any federal, state, local or non-U.S. tax on behalf of any current or former unitholder or our general partner, we are authorized to treat the payment as a distribution of cash to the relevant unitholder or general partner. Where the tax is payable on behalf of all unitholders or we cannot determine the specific unitholder on whose behalf the tax is payable, we are authorized to treat the payment as a distribution to all current unitholders. Payments by us as described above could give rise to an overpayment of tax on behalf of a unitholder, in which event the unitholder may be entitled to claim a refund of the overpayment amount.

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Unitholders are urged to consult their tax advisors to determine the consequences to them of any tax payment we make on their behalf.

Allocation of Income, Gain, Loss and Deduction

Our items of income, gain, loss and deduction generally will be allocated among our unitholders in accordance with their percentage interests in us. At any time that we make incentive distributions, gross income will be allocated to the recipients to the extent of these distributions.

Specified items of our income, gain, loss and deduction will be allocated under Section 704(c) of the Code (or the principles of Section 704(c) of the Code) to account for any difference between the tax basis and fair market value of our assets at the time such assets are contributed to us and at the time of any subsequent offering of our units (a "Book-Tax Disparity"). As a result, the federal income tax burden associated with any Book-Tax Disparity immediately prior to an offering generally will be borne by our partners holding interests in us prior to such offering. In addition, items of recapture income will be specially allocated to the extent possible to the unitholder who was allocated the deduction giving rise to that recapture income in order to minimize the recognition of ordinary income by other unitholders.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by the Code to eliminate a Book-Tax Disparity, will generally be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction only if the allocation has "substantial economic effect." In any other case, a partner's share of an item will be determined on the basis of the partner's interest in us, which will be determined by taking into account all the facts and circumstances, including (i) the partner's relative contributions to us, (ii) the interests of all the partners in profits and losses , (iii) the interest of all the partners in cash flow and (iv) the rights of all the partners to distributions of capital upon liquidation. Vinson & Elkins L.L.P. is of the opinion that, with the exception of the issues described in "—Section 754 Election" and "—Disposition of Units—Allocations Between Transferors and Transferees," allocations of income, gain, loss or deduction under our partnership agreement will be given effect for federal income tax purposes.

Treatment of Securities Loans

A unitholder whose units are loaned (for example, a loan to "short seller" to cover a short sale of units) may be treated as having disposed of those units. If so, such unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period (i) any of our income, gain, loss or deduction allocated to those units would not be reportable by the lending unitholder, and (ii) any cash distributions received by the unitholder as to those units may be treated as ordinary taxable income.

Due to a lack of controlling authority, Vinson & Elkins L.L.P. has not rendered an opinion regarding the tax treatment of a unitholder that enters into a securities loan with respect to its units. Unitholders desiring to assure their status as partners and avoid the risk of income recognition from a loan of their units are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and lending their units. The IRS has announced that it is studying issues relating to the tax treatment of short sales of partnership interests. Please read "—Disposition of Units—Recognition of Gain or Loss."

Tax Rates

Under current law, the highest marginal federal income tax rates for individuals applicable to ordinary income and long-term capital gains (generally, gains from the sale or exchange of certain investment assets held for more than one year) are 39.6% and 20%, respectively. These rates are subject to change by new legislation at any time.

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In addition, a 3.8% net investment income tax applies to certain net investment income earned by individuals, estates, and trusts. For these purposes, net investment income generally includes a unitholder's allocable share of our income and gain realized by a unitholder from a sale of units. In the case of an individual, the tax will be imposed on the lesser of (i) the unitholder's net investment income from all investments, or (ii) the amount by which the unitholder's modified adjusted gross income exceeds $250,000 (if the unitholder is married and filing jointly or a surviving spouse), $125,000 (if married filing separately) or $200,000 (if the unitholder is unmarried or in any other case). In the case of an estate or trust, the tax will be imposed on the lesser of (i) undistributed net investment income, or (ii) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

Section 754 Election

We will make the election permitted by Section 754 of the Code that permits us to adjust the tax bases in our assets as to specific purchasers of our units under Section 743(b) of the Code. That election is irrevocable without the consent of the IRS. The Section 743(b) adjustment separately applies to each purchaser of units based upon the values and bases of our assets at the time of the relevant purchase, and the adjustment will reflect the purchase price paid. The Section 743(b) adjustment does not apply to a person who purchases units directly from us.

Under our partnership agreement, we are authorized to take a position to preserve the uniformity of units even if that position is not consistent with applicable Treasury Regulations. A literal application of Treasury Regulations governing a 743(b) adjustment attributable to properties depreciable under Section 167 of the Code may give rise to differences in the taxation of unitholders purchasing units from us and unitholders purchasing from other unitholders. If we have any such properties, we intend to adopt methods employed by other publicly traded partnerships to preserve the uniformity of units, even if inconsistent with existing Treasury Regulations, and Vinson & Elkins L.L.P. has not opined on the validity of this approach. Moreover, we plan to adopt an allocation methodology with respect our coal properties that generate excess percentage depletion which may be inconsistent with the Treasury Regulations under Sections 704(b) and 743(b), but which is necessary in order to retain the uniformity of our units and provide appropriate tax consequences to each unitholder. Vinson & Elkins L.L.P. has not opined on whether our method under Sections 704(b) and 743(b) as it relates to excess percentage depletion is sustainable under the Treasury Regulations. Please read "—Disposition of Units—Uniformity of Units."

The IRS may challenge the positions we adopt with respect to depreciating or amortizing the Section 743(b) adjustment we take to preserve the uniformity of units due to lack of controlling authority. Because a unitholder's tax basis for its units is reduced by its share of our items of deduction or loss, any position we take that understates deductions will overstate a unitholder's basis in its units, and may cause the unitholder to understate gain or overstate loss on any sale of such units. Please read "—Disposition of Units—Recognition of Gain or Loss." If a challenge to such treatment were sustained, the gain from the sale of units may be increased without the benefit of additional deductions.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. The IRS could seek to reallocate some or all of any Section 743(b) adjustment we allocated to our assets subject to depreciation to goodwill or nondepreciable assets. Goodwill, as an intangible asset, is generally nonamortizable or amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure any unitholder that the determinations we make will not be successfully challenged by the IRS or that the resulting deductions will not be reduced or disallowed altogether. Should the IRS require a different tax basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754

election. If permission is granted, a subsequent purchaser of units may be allocated more income than it would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting Method and Taxable Year

We will use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each unitholder will be required to include in income its share of our income, gain, loss and deduction for each taxable year ending within or with its taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of its units following the close of our taxable year but before the close of its taxable year must include its share of our income, gain, loss and deduction in income for its taxable year, with the result that it will be required to include in income for its taxable year its share of more than one year of our income, gain, loss and deduction. Please read "—Disposition of Units—Allocations Between Transferors and Transferees."

Tax Basis, Depreciation and Amortization

The tax bases of our assets will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. If we dispose of depreciable property by sale, foreclosure or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation and depletion deductions previously taken, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a unitholder who has taken cost recovery or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of its interest in us. Please read "—Tax Consequences of Unit Ownership—Allocation of Income, Gain, Loss and Deduction."

The costs we incur in offering and selling our common units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon our termination. While there are uncertainties regarding the classification of costs as organization expenses, which may be amortized by us, and as syndication expenses, which may not be amortized by us, the underwriting discounts we incur will be treated as syndication expenses.

Valuation and Tax Basis of Our Properties

The federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values and the initial tax bases of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates and determinations of tax basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deduction previously reported by unitholders could change, and unitholders could be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Coal Depletion

In general, we are entitled to depletion deductions with respect to coal mined from the underlying mineral property. We generally are entitled to the greater of cost depletion limited to the basis of the property or percentage depletion. The percentage depletion rate for coal is 10%.

Depletion deductions we claim generally will reduce the tax basis of the underlying mineral property. Percentage depletion deductions can, however, exceed the total tax basis of the mineral property. The excess of our percentage depletion deductions over the adjusted tax basis of the property

at the end of the taxable year is subject to tax preference treatment in computing the alternative minimum tax. Upon the disposition of the mineral property, a portion of the gain, if any, equal to the lesser of the deductions for depletion which reduce the adjusted tax basis of the mineral property plus deductible development and mining exploration expenses, or the amount of gain recognized on the disposition, will be treated as ordinary income to us. In addition, a corporate unitholder's allocable share of the amount allowable as a percentage depletion deduction for any property will be reduced by 20% of the excess, if any, of that partner's allocable share of the amount of the percentage depletion deductions for the taxable year over the adjusted tax basis of the mineral property as of the close of the taxable year.

Mining Exploration and Development Expenditures

We will elect to currently deduct mining exploration expenditures that we pay or incur to determine the existence, location, extent or quality of coal deposits prior to the time the existence of coal in commercially marketable quantities has been disclosed.

Amounts we deduct for mine exploration expenditures must be recaptured and included in our taxable income at the time a mine reaches the production stage, unless we elect to reduce future depletion deductions by the amount of the recapture. A mine reaches the producing stage when the major part of the coal production is obtained from working mines other than those opened for the purpose of development or the principal activity of the mine is the production of developed coal rather than the development of additional coal for mining. This recapture is accomplished through the disallowance of both cost and percentage depletion deductions on the particular mine reaching the production stage. This disallowance of depletion deductions continues until the amount of adjusted exploration expenditures with respect to the mine have been fully recaptured. This recapture is not applied to the full amount of the previously deducted exploration expenditures. Instead, these expenditures are reduced by the amount of percentage depletion, if any, that was lost as a result of deducting these exploration expenditures.

Mine development costs incurred during the development phase are capitalized and revenue from the incidental sale of coal while a mine is in the development phase is recorded as a reduction of the related mine development costs.

Mine exploration and development expenditures are subject to recapture as ordinary income to the extent of any gain upon a sale or other disposition of our property or of your common units. Please read "—Disposition of Units." Corporate unitholders are subject to an additional rule that requires them to capitalize a portion of their otherwise deductible mine exploration and development expenditures. Corporate unitholders, other than some S corporations, are required to reduce their otherwise deductible exploration expenditures by 30%. These capitalized mine exploration and development expenditures must be amortized over a 60-month period, beginning in the month paid or incurred, using a straight-line method and may not be treated as part of the basis of the property for the purposes of computing depletion.

When computing the alternative minimum tax, mine exploration and development expenditures are capitalized and deducted over a ten year period. Unitholders may avoid this alternative minimum tax adjustment of their mine exploration and development expenditures by electing to capitalize all or part of the expenditures and deducting them over ten years for regular income tax purposes. You may select the specific amount of these expenditures for which you wish to make this election.

Sales of Coal Reserves

If any coal reserves are sold or otherwise disposed of in a taxable transaction, we will recognize gain or loss measured by the difference between the amount realized (including the amount of any indebtedness assumed by purchaser upon such disposition or to which such property is subject) and the

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adjusted tax basis of the property sold. Generally, the character of any gain or loss recognized upon that disposition will depend upon whether our coal reserves or the mined coal sold are held by us:

- for sale to customers in the ordinary course of business (i.e., we are a "dealer" with respect to that property);
- for use in a trade or business within the meaning of Section 1231 of the Code; or
- as a capital asset within the meaning of Section 1221 of the Code.

In determining dealer status with respect to coal reserves and other types of real estate, the courts have identified a number of factors for distinguishing between a particular property held for sale in the ordinary course of business and one held for investment. Any determination must be based on all the facts and circumstances surrounding the particular property for sale in question.

We intend to hold our coal reserves for use in a trade or business, achieving long-term capital appreciation. Although our general partner may consider strategic sales of coal reserves consistent with achieving long-term capital appreciation, our general partner does not anticipate frequent sales of coal reserves. Thus, the general partner does not believe we will be viewed as a dealer. In light of the factual nature of this question, however, there is no assurance that our purposes for holding our properties will not change and that our future activities will not cause us to be a "dealer" in coal reserves.

If we are not a dealer with respect to our coal reserves and we have held the disposed property for more than a one-year period primarily for use in our trade or business, the character of any gain or loss realized from a disposition of the property will be determined under Section 1231 of the Code. If we have not held the property for more than one year at the time of the sale, gain or loss from the sale will be taxable as ordinary income.

A unitholder's distributive share of any Section 1231 gain or loss generated by us will be aggregated with any other gains and losses realized by that unitholder from the disposition of property used in the trade or business, as defined in Section 1231(b) of the Code, and from the involuntary conversion of such properties and of capital assets held in connection with a trade or business or a transaction entered into for profit for the requisite holding period. If a net gain results, all such gains and losses will be long-term capital gains and losses; if a net loss results, all such gains and losses will be ordinary income and losses. Net Section 1231 gains will be treated as ordinary income to the extent of prior net Section 1231 losses of the taxpayer or predecessor taxpayer for the five most recent prior taxable years to the extent such losses have not previously been offset against Section 1231 gains. Losses are deemed recaptured in the chronological order in which they arose.

If we are not a dealer with respect to our coal reserves and that property is not used in a trade or business, the property will be a "capital asset" within the meaning of Section 1221 of the Code. Gain or loss recognized from the disposition of that property will be taxable as capital gain or loss, and the character of such capital gain or loss as long-term or short-term will be based upon our holding period of such property at the time of its sale. The requisite holding period for long-term capital gain is more than one year.

Upon a disposition of coal reserves, a portion of the gain, if any, equal to the lesser of (1) the depletion deductions that reduced the tax basis of the disposed mineral property plus deductible development and mining exploration expenses or (2) the amount of gain recognized on the disposition, will be treated as ordinary income to us.

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Deduction for U.S. Production Activities

Subject to the limitations on the deductibility of losses discussed above and the limitation described below, unitholders will be entitled to a deduction, herein referred to as the Section 199 deduction, equal to a specified percentage of our qualified production activities income that is allocated to such unitholder. The percentage is currently 9% for qualified production activities income.

Qualified production activities income is generally equal to gross receipts from domestic production activities reduced by cost of goods sold allocable to those receipts, other expenses directly associated with those receipts, and a share of other deductions, expenses and losses that are not directly allocable to those receipts or another class of income. The products produced must be manufactured, produced, grown or extracted in whole or in significant part by the taxpayer in the United States.

For a partnership, the Section 199 deduction is determined at the partner level. To determine its Section 199 deduction, each unitholder will aggregate its share of the qualified production activities income allocated to him from us with the unitholder's qualified production activities income from other sources. Each unitholder must take into account its distributive share of the expenses allocated to him from our qualified production activities regardless of whether we otherwise have taxable income. However, our expenses that otherwise would be taken into account for purposes of computing the Section 199 deduction are only taken into account if and to the extent the unitholder's share of losses and deductions from all of our activities is not disallowed by the basis rules, the at-risk rules or the passive activity loss rules. Please read "—Tax Consequences of Unit Ownership —Limitations on Deductibility of Losses."

The amount of a unitholder's Section 199 deduction for each year is limited to 50% of the IRS Form W-2 wages actually or deemed paid by the unitholder during the calendar year that are deducted in arriving at qualified production activities income. Each unitholder is treated as having been allocated IRS Form W-2 wages from us equal to the unitholder's allocable share of our wages that are deducted in arriving at qualified production activities income for that taxable year. It is not anticipated that we or our subsidiaries will pay material wages that will be allocated to our unitholders, and thus a unitholder's ability to claim the Section 199 deduction may be limited.

Recent Legislative Developments

The White House has recommended various legislative changes affecting the U.S. federal income tax preferences relating to coal exploration and development in the 2015 Budget Proposal. Among the changes recommended in the 2015 Budget Proposal is the elimination of certain key U.S. federal income tax preferences relating to coal exploration and development discussed above. The 2015 Budget Proposal would (1) repeal the expensing of exploration and development costs relating to coal, (2) repeal the percentage depletion allowance with respect to coal properties, (3) repeal capital gains treatment for coal royalties and (4) repeal the domestic manufacturing deduction for the production of coal. The passage of any legislation as a result of the 2015 Budget Proposal or any other similar changes in U.S. federal income tax laws could eliminate certain tax deductions that are currently available with respect to coal exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units.

Disposition of Units

Recognition of Gain or Loss

A unitholder will be required to recognize gain or loss on a sale of units equal to the difference between the unitholder's amount realized and tax basis in the units sold. A unitholder's amount

realized generally will equal the sum of the cash or the fair market value of other property it receives plus its share of our liabilities with respect to such units. Because the amount realized includes a unitholder's share of our liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Except as noted below, gain or loss recognized by a unitholder on the sale or exchange of a unit held for more than one year generally will be taxable as long-term capital gain or loss. However, gain or loss recognized on the disposition of units will be separately computed and taxed as ordinary income or loss under Section 751 of the Code to the extent attributable to Section 751 Assets, such as depreciation or depletion recapture. Ordinary income attributable to Section 751 Assets may exceed net taxable gain realized on the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and capital gain or loss upon a sale of units. Net capital loss may offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year.

For purposes of calculating gain or loss on the sale of units, the unitholder's tax basis will be adjusted by its allocable share of our income or loss in respect of its units for the year of the sale. Furthermore, as described above, the IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method, which generally means that the tax basis allocated to the interest sold equals an amount that bears the same relation to the partner's tax basis in its entire interest in the partnership as the value of the interest sold bears to the value of the partner's entire interest in the partnership.

Treasury Regulations under Section 1223 of the Code allow a selling unitholder who can identify units transferred with an ascertainable holding period to elect to use the actual holding period of the units transferred. Thus, according to the ruling discussed in the paragraph above, a unitholder will be unable to select high or low basis units to sell as would be the case with corporate stock, but, according to the Treasury Regulations, it may designate specific units sold for purposes of determining the holding period of units transferred. A unitholder electing to use the actual holding period of units transferred must consistently use that identification method for all subsequent sales or exchanges of our units. A unitholder considering the purchase of additional units or a sale of units purchased in separate transactions is urged to consult its tax advisor as to the possible consequences of this ruling and application of the Treasury Regulations.

Specific provisions of the Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" financial position, including a partnership interest with respect to which gain would be recognized if it were sold, assigned or terminated at its fair market value, in the event the taxpayer or a related person enters into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

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Allocations Between Transferors and Transferees

In general, our taxable income or loss will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the unitholders in proportion to the number of units owned by each of them as of the opening of the applicable exchange on the first business day of the month (the "Allocation Date"). However, gain or loss realized on a sale or other disposition of our assets or, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction will be allocated among the unitholders on the Allocation Date in the month in which such income, gain, loss or deduction is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss and deduction realized after the date of transfer.

Although simplifying conventions are contemplated by the Code and most publicly traded partnerships use similar simplifying conventions, the use of this method may not be permitted under existing Treasury Regulations. Recently, however, the Department of the Treasury and the IRS issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders, although such tax items must be prorated on a daily basis. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. Accordingly, Vinson & Elkins L.L.P. is unable to opine on the validity of this method of allocating income and deductions between transferee and transferor unitholders. If this method is not allowed under the final Treasury Regulations, or only applies to transfers of less than all of the unitholder’s interest, our taxable income or losses could be reallocated among our unitholders. We are authorized to revise our method of allocation between transferee and transferor unitholders, as well as among unitholders whose interests vary during a taxable year, to conform to a method permitted under future Treasury Regulations.

A unitholder who disposes of units prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deduction attributable to the month of disposition but will not be entitled to receive a cash distribution for that period.

Notification Requirements

A unitholder who sells or purchases any of its units is generally required to notify us in writing of that transaction within 30 days after the transaction (or, if earlier, January 15 of the year following the transaction in the case of a seller). Upon receiving such notifications, we are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. Failure to notify us of a transfer of units may, in some cases, lead to the imposition of penalties. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who effects the sale through a broker who will satisfy such requirements.

Constructive Termination

We will be considered to have "constructively" terminated as a partnership for federal income tax purposes upon the sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Immediately following this offering, our sponsor will own, directly and indirectly, more than 50% of the total interests in our capital and profits. Therefore, a transfer by our sponsor of all or a portion of its interests in us could result in a termination of us as a partnership for federal income tax purposes. For such purposes, multiple sales of the same unit are counted only once. A constructive termination results in the closing of our taxable year for all unitholders. In the case of a unitholder reporting on a taxable year other than the calendar year, the closing of our taxable year may result in more than twelve months of our taxable income or loss being includable in such unitholder’s taxable income for the year of termination.

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A constructive termination occurring on a date other than December 31 generally would require that we file two tax returns for one fiscal year and the cost of the preparation of these returns will be borne by all unitholders. However, pursuant to an IRS relief procedure the IRS may allow a constructively terminated partnership to provide a single Schedule K-1 for the calendar year in which a termination occurs. Following a constructive termination, we would be required to make new tax elections, including a new election under Section 754 of the Code, and the termination would result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination may either accelerate the application of, or subject us to, any tax legislation enacted before the termination that would not otherwise have been applied to us as a continuing as opposed to a terminating partnership.

Uniformity of Units

Because we cannot match transferors and transferees of units and other reasons, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements. Any non-uniformity could have a negative impact on the value of the units. Please read "—Tax Consequences of Unit Ownership—Section 754 Election."

Our partnership agreement permits our general partner to take positions in filing our tax returns that preserve the uniformity of our units. These positions may include reducing the depreciation, amortization or loss deductions to which a unitholder would otherwise be entitled or reporting a slower amortization of Section 743(b) adjustments for some unitholders than that to which they would otherwise be entitled. Vinson & Elkins L.L.P. is unable to opine as to validity of such filing positions.

A unitholder's basis in units is reduced by its share of our deductions (whether or not such deductions were claimed on an individual income tax return) so that any position that we take that understates deductions will overstate the unitholder's basis in its units, and may cause the unitholder to understate gain or overstate loss on any sale of such units. Please read "—Recognition of Gain or Loss" above and "—Tax Consequences of Unit Ownership—Section 754 Election" above. The IRS may challenge one or more of any positions we take to preserve the uniformity of units. If such a challenge were sustained, the uniformity of units might be affected, and, under some circumstances, the gain from the sale of units might be increased without the benefit of additional deductions.

Tax-Exempt Organizations and Other Investors

Ownership of units by employee benefit plans and other tax-exempt organizations, as well as by non-resident alien individuals, non-U.S. corporations and other non-U.S. persons raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them. Prospective unitholders that are tax-exempt entities or non-U.S. persons should consult their tax advisors before investing in our units. Employee benefit plans and most other tax-exempt organizations, including IRAs and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income will be unrelated business taxable income and will be taxable to a tax-exempt unitholder. Moreover, under our partnership agreement, non-U.S. persons are not Eligible Holders of our units and units held by non-U.S. persons may be subject to redemption. Please read "The Partnership Agreement—Non-Eligible Holders; Redemption."

Non-U.S. unitholders are taxed by the United States on income effectively connected with a U.S. trade or business ("effectively connected income") and on certain types of U.S.-source non-effectively connected income (such as dividends), and will be treated as engaged in business in the United States because of their ownership of our units. Furthermore, it is probable that they will be deemed to conduct such activities through a permanent establishment in the United States within the meaning of any applicable tax treaty. Consequently, they will be required to file federal tax returns to report their

share of our income, gain, loss or deduction and pay federal income tax at regular rates on their share of our net income or gain. Moreover, under rules applicable to publicly traded partnerships, distributions to non-U.S. unitholders are subject to withholding at the highest applicable effective tax rate. Each non-U.S. unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8BEN or applicable substitute form in order to obtain credit for these withholding taxes.

In addition, because a foreign corporation that owns units will be treated as engaged in a U.S. trade or business, that corporation may be subject to the U.S. branch profits tax at a rate of 30%, in addition to regular federal income tax, on its share of our income and gain to the extent reflected in earnings and profits, and as adjusted for changes in the foreign corporation's "U.S. net equity." That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate unitholder is a "qualified resident." In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Code.

A non-U.S. unitholder who sells or otherwise disposes of a unit will be subject to federal income tax on gain realized from the sale or disposition of that unit to the extent the gain is effectively connected with a U.S. trade or business of the non-U.S. unitholder. Under a ruling published by the IRS interpreting the scope of "effectively connected income," part or all of a non-U.S. unitholder's gain from the sale or disposition of units may be treated as effectively connected with that unitholder's indirect U.S. trade or business constituted by its investment in us. Moreover, under the Foreign Investment in Real Property Tax Act, a non-U.S. unitholder generally will be subject to federal income tax upon the sale or disposition of a unit if (i) it owned (directly or constructively applying certain attribution rules) more than 5% of our units at any time during the five-year period ending on the date of such disposition and (ii) 50% or more of the fair market value of all of our assets consisted of U.S. real property interests at any time during the shorter of the period during which such unitholder held the units or the 5-year period ending on the date of disposition. Currently, more than 50% of our assets consist of U.S. real property interests and we do not expect that to change in the foreseeable future. Therefore, non-U.S. unitholders may be subject to federal income tax on gain from the sale or disposition of their units.

Administrative Matters

Information Returns and Audit Procedures

We intend to furnish to each unitholder, within 90 days after the close of each taxable year, specific tax information, including a Schedule K-1, which describes its share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine each unitholder's share of income, gain, loss and deduction. We cannot assure our unitholders that those positions will yield a result that conforms to all of the requirements of the Code, Treasury Regulations or administrative interpretations of the IRS.

The IRS may audit our federal income tax information returns. Neither we nor Vinson & Elkins L.L.P. can assure prospective unitholders that the IRS will not successfully challenge the positions we adopt, and such a challenge could adversely affect the value of the units. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability and may result in an audit of the unitholder's own return. Any audit of a unitholder's return could result in adjustments unrelated to our returns.

Publicly traded partnerships generally are treated as entities separate from their owners for purposes of federal income tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings of the partners. The Code

requires that one partner be designated as the "Tax Matters Partner" for these purposes, and our partnership agreement designates our general partner.

The Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits or by any group of unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review may go forward, and each unitholder with an interest in the outcome may participate in that action.

A unitholder must file a statement with the IRS identifying the treatment of any item on its federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

Nominee Reporting

Persons who hold an interest in us as a nominee for another person are required to furnish to us:

(1) the name, address and taxpayer identification number of the beneficial owner and the nominee;

(2) a statement regarding whether the beneficial owner is:

  (a) a non-U.S. person;

  (b) a non-U.S. government, an international organization or any wholly-owned agency or instrumentality of either of the foregoing; or

  (c) a tax-exempt entity;

(3) the amount and description of units held, acquired or transferred for the beneficial owner; and

(4) specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are U.S. persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $100 per failure, up to a maximum of $1.5 million per calendar year, is imposed by the Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Accuracy-Related Penalties

Certain penalties may be imposed as a result of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for the underpayment of that portion and that the taxpayer acted in good faith regarding the underpayment of that portion. We do not anticipate that any accuracy-related penalties will be assessed against us.

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State, Local and Other Tax Considerations

In addition to federal income taxes, unitholders may be subject to other taxes, including state and local income taxes, unincorporated business taxes, and estate, inheritance or intangibles taxes that may be imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if you do not live in those jurisdictions. We will initially own assets and conduct business in various states (including Utah, Kentucky and Colorado), each of which imposes a personal income tax on individuals and an income tax on corporations and other entities. We may also own property or do business in other states in the future that impose income or similar taxes on nonresident individuals. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider their potential impact on its investment in us.

Although you may not be required to file a return and pay taxes in some jurisdictions because your income from that jurisdiction falls below the filing and payment requirement, you will be required to file income tax returns and to pay income taxes in many of these jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. It is your responsibility to file all U.S. federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our common units.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent jurisdictions, of its investment in us. We strongly recommend that each prospective unitholder consult, and depend upon, its own tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state, local and non-U.S., as well as U.S. federal tax returns that may be required of it. Vinson & Elkins L.L.P. has not rendered an opinion on the state, local, alternative minimum tax or non-U.S. tax consequences of an investment in us.

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INVESTMENT IN BOWIE RESOURCE PARTNERS LP BY EMPLOYEE BENEFIT PLANS

An investment in us by an employee benefit plan is subject to additional considerations because the investments of these plans are subject to the fiduciary responsibility and prohibited transaction provisions of ERISA, restrictions imposed by Section 4975 of the Code, and/or provisions under any federal, state, local, non-U.S. or other laws or regulations that are similar to such provisions of the Code or ERISA (collectively, "Similar Laws"). For these purposes, the term "employee benefit plan" includes qualified pension, profit-sharing and unit bonus plans, Keogh plans, simplified employee pension plans and tax deferred annuities or IRAs or annuities and entities whose underlying assets are considered to include "plan assets" of such plans, accounts or arrangements. Among other things, consideration should be given to:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA and any other applicable Similar Laws;
- whether in making the investment, the plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA and any other applicable Similar Laws; and
- whether the investment will result in recognition of unrelated business taxable income by the plan and, if so, the potential after-tax investment return. Please read "Material U.S. Federal Income Tax Consequences—Tax-Exempt Organizations and Other Investors."

The person with investment discretion with respect to the assets of an employee benefit plan, often called a fiduciary, should determine whether an investment in us is authorized by the appropriate governing instrument and is a proper investment for the plan.

Section 406 of ERISA and Section 4975 of the Code prohibit employee benefit plans from engaging in specified transactions involving "plan assets" with parties that are "parties in interest" under ERISA or "disqualified persons" under the Code with respect to the plan.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary of an employee benefit plan should consider whether the plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Code and any other applicable Similar Laws.

The Department of Labor regulations provide guidance with respect to whether the assets of an entity in which employee benefit plans acquire equity interests would be deemed "plan assets" under some circumstances. Under these regulations, an entity's assets would not be considered to be "plan assets" if, among other things:

(1) the equity interests acquired by employee benefit plans are publicly offered securities—i.e., the equity interests are widely held by 100 or more investors independent of the issuer and each other, freely transferable and registered under some provisions of the federal securities laws;

(2) the entity is an "operating company"—i.e., it is primarily engaged in the production or sale of a product or service other than the investment of capital either directly or through a majority-owned subsidiary or subsidiaries; or

(3) there is no significant investment by benefit plan investors, which is defined to mean that less than 25% of the value of each class of equity interest is held by the employee benefit plans referred to above.

Plan fiduciaries contemplating a purchase of common units should consult with their own counsel regarding the consequences under ERISA, the Code and any other applicable Similar Laws in light of the serious penalties imposed on persons who engage in prohibited transactions or other violations.

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UNDERWRITING

Citigroup Global Markets Inc., Morgan Stanley & Co. LLC, Deutsche Bank Securities Inc., UBS Securities LLC, Credit Suisse Securities (USA) LLC and Stifel, Nicolaus & Company, Incorporated are acting as joint book-running managers of this offering, and Citigroup Global Markets Inc., Morgan Stanley & Co. LLC and Deutsche Bank Securities Inc. are acting as representatives of the underwriters. Subject to the terms and conditions stated in the underwriting agreement dated the date of this prospectus, each underwriter named below has severally agreed to purchase, and we have agreed to sell to that underwriter, the number of common units set forth opposite the underwriter's name below:

Underwriters	Number of Common Units
Citigroup Global Markets Inc.	
Morgan Stanley & Co. LLC	
Deutsche Bank Securities Inc.	
UBS Securities LLC	
Credit Suisse Securities (USA) LLC	
Stifel, Nicolaus & Company, Incorporated	
Brean Capital, LLC	
Total	

The underwriting agreement provides that the obligations of the underwriters to purchase the common units included in this offering are subject to approval of legal matters by counsel and to other conditions. The underwriters are obligated to purchase all the common units (other than those covered by the underwriters' over-allotment option described below) if they purchase any of the common units.

Common units sold by the underwriters to the public will initially be offered at the initial public offering price set forth on the cover of this prospectus. Any common units sold by the underwriters to securities dealers may be sold at a discount from the initial public offering price not to exceed $ per common unit. After the common units are released for sale to the public, if all the common units are not sold at the initial offering price, the underwriters may change the offering price and the other selling terms. The representatives have advised us that the underwriters do not intend to confirm sales to discretionary accounts that exceed % of the total number of common units offered by them.

If the underwriters sell more common units than the total number set forth in the table above, we have granted to the underwriters an option, exercisable for 30 days from the date of this prospectus, to purchase up to additional common units at the public offering price less the underwriting discount. To the extent the option is exercised, each underwriter must purchase a number of additional common units approximately proportionate to that underwriter's initial purchase commitment. Any common units issued or sold under the option will be issued and sold on the same terms and conditions as the other common units that are the subject of this offering.

We, our sponsor, our general partner and certain officers and directors of our sponsor and our general partner have agreed that, for a period of 180 days from the date of this prospectus, we and they will not, without the prior written consent of , dispose of or hedge any common units or any securities convertible into or exchangeable for our common units, with certain exceptions.

Notwithstanding the foregoing, if (i) during the last 17 days of the 180-day restricted period, we issue an earnings release or material news or a material event relating to our company occurs; or (ii) prior to the expiration of the 180-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 180-day restricted period, the restrictions described above shall continue to apply until the expiration of the 18-day period beginning

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on the issuance of the earnings release or the occurrence of the material news or material event. , in their sole discretion, may release any of the securities subject to these lock-up agreements at any time and without notice.

Prior to this offering, there has been no public market for our common units. Consequently, the initial public offering price for the common units was determined by negotiations among us and the representatives. Among the factors considered in determining the initial public offering price were our results of operations, our current financial condition, our future prospects, our markets, the economic conditions in and future prospects for the industry in which we compete, our management, and currently prevailing general conditions in the equity securities markets, including current market valuations of publicly traded companies considered comparable to our company. We cannot assure you, however, that the price at which the common units will sell in the public market after this offering will not be lower than the initial public offering price or that an active trading market in our common units will develop and continue after this offering.

We will apply to have our common units listed on the NYSE under the symbol "BRLP."

The following table shows the underwriting discounts that we will pay to the underwriters in connection with this offering. These amounts are shown assuming both no exercise and full exercise of the underwriters' over-allotment option.

	No Exercise	Full Exercise
Per common unit	$	$
Total	$	$

We estimate that the expenses of the offering, not including the underwriting discount, will be approximately $ million, all of which will be paid by us.

In connection with the offering, the underwriters may purchase and sell common units in the open market. Purchases and sales in the open market may include short sales, purchases to cover short positions, which may include purchases pursuant to the underwriters' over-allotment option and stabilizing purchases. The underwriters also may impose penalty bids.

- Short sales involve secondary market sales by the underwriters of a greater number of common units than they are required to purchase in the offering.
  - "Covered" short sales are sales of common units in an amount up to the number of common units represented by the underwriters' over-allotment option.
  - "Naked" short sales are sales of common units in an amount in excess of the number of common units represented by the underwriters' over-allotment option.
- Covering transactions involve purchases of common units either pursuant to the underwriters' over-allotment option or in the open market after the distribution has been completed in order to cover short positions.
  - To close a naked short position, the underwriters must purchase common units in the open market after the distribution has been completed. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the common units in the open market after pricing that could adversely affect investors who purchase in the offering.
  - To close a covered short position, the underwriters must purchase common units in the open market after the distribution has been completed or must exercise the over-allotment option. In determining the source of common units to close the covered short position, the underwriters will consider, among other things, the price of common units available for

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purchase in the open market as compared to the price at which they may purchase common units through the underwriters' over-allotment option.

- Stabilizing transactions involve bids to purchase common units so long as the stabilizing bids do not exceed a specified maximum.
- Penalty bids permit the underwriters to reclaim a selling concession from a syndicate member when the underwriters, in covering short positions or making stabilizing purchases, repurchase common units originally sold by that syndicate member.

Purchases to cover short positions and stabilizing purchases, as well as other purchases by the underwriters for their own accounts, may have the effect of preventing or retarding a decline in the market price of the common units. They may also cause the price of the common units to be higher than the price that would otherwise exist in the open market in the absence of these transactions. The underwriters may conduct these transactions on the New York Stock Exchange, in the over-the-counter market or otherwise. If the underwriters commence any of these transactions, they may discontinue them at any time.

A prospectus in electronic format may be available on the websites or through other online services maintained by one or more of the underwriters participating in this offering, or by their affiliates. The underwriters may agree to allocate a specific number of common units for sale to online brokerage account holders. Any such allocation for online distributions will be made by the underwriters on the same basis as other allocations.

Other than the prospectus in electronic format, the information on any underwriter's or selling group member's website and any information contained in any other website maintained by an underwriter or selling group member is not part of this prospectus or the registration statement of which this prospectus forms a part, has not been approved or endorsed by us or any underwriter or selling group member in its capacity as underwriter or selling group member and should not be relied upon by investors.

Certain of the underwriters and their affiliates have engaged, and may in the future engage, in commercial banking, investment banking and advisory services for us, our sponsor or our respective affiliates from time to time in the ordinary course of their business for which they have received customary fees and reimbursement of expenses. Affiliates of certain of the underwriters are lenders under our new revolving credit facility. In addition, Mr. John DeRosa, who is expected to become a member of the board of directors of our general partner in connection with the closing of this offering, is currently the Head of Tax for the Americas for Deutsche Bank.

We expect that a portion of the net proceeds distributed to our sponsor will be used by our sponsor to repay outstanding indebtedness under our sponsor's Senior Secured Credit Facilities, as well as related fees and expenses. Affiliates of Morgan Stanley & Co. LLC and Deutsche Bank Securities Inc. are lenders under our sponsor's Senior Secured Credit Facilities and, accordingly, may ultimately receive a portion of the net proceeds from the offering of our New Notes. Citigroup Global Markets Inc., Morgan Stanley & Co. LLC and Deutsche Bank Securities Inc. are also initial purchasers in connection with the New Notes offering. Other than the participation as lenders under the such credit facilities or as described in this prospectus, none of the underwriters has provided or will provide financing, investment or advisory services to us during the 180-day period prior to or the 90-day period following the date of this prospectus.

The underwriters are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities)

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and financial instruments (which may include bank loans and/or credit default swaps) for their own account and for the accounts of their customers and may at any time hold long and short positions in such securities and instruments. Such investment and securities activities may involve our securities and instruments.

Because the Financial Industry Regulatory Authority, Inc. ("FINRA") views the common units offered hereby as interests in a direct participation program, this offering is being made in compliance with FINRA Rule 2310. Investor suitability with respect to the common units should be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

We, our sponsor, our general partner and certain of our affiliates have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act, or to contribute to payments the underwriters may be required to make because of any of those liabilities.

LEGAL MATTERS

The validity of our common units and certain other legal matters will be passed upon for us by Vinson & Elkins L.L.P., New York, New York. Certain legal matters in connection with this offering will be passed upon for the underwriters by Baker Botts L.L.P., Houston, Texas.

EXPERTS

The consolidated balance sheet of Bowie Resource Partners LP as of March 31, 2015 and the financial statements of Canyon Fuel Company, LLC as of December 31, 2014 and for the year then ended appearing in this prospectus and registration statement have been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in their report thereon appearing elsewhere herein, and are included in reliance upon such report given on the authority of such firm as experts in accounting and auditing.

The financial statements of Canyon Fuel Company, LLC as of December 31, 2013 and for the period from August 16, 2013 to December 31, 2013 appearing in this prospectus and registration statement have been audited by Coulter & Justus, PC, independent registered public accounting firm, as set forth in their report thereon appearing elsewhere herein, and is included in reliance upon such report given on the authority of such firm as experts in accounting and auditing.

The financial statements of Canyon Fuel Company, LLC for the period from January 1, 2013 to August 16, 2013 appearing in this prospectus and registration statement have been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in their report thereon appearing elsewhere herein, and are included in reliance upon such report given on the authority of such firm as experts in accounting and auditing.

The coal reserves are based on SEC compliant reserve statements prepared by Norwest Corporation, an independent international mining consultancy. Those statements have been included with their expert's qualification to perform such studies and prepare requisite documents.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 (including the exhibits, schedules and amendments thereto) under the Securities Act with respect to the common units being offered hereunder. This prospectus does not contain all of the information set forth in the registration statement and the exhibits and schedules to the registration statement. For further information with respect to us and our common units, we refer you to the registration statement and the exhibits filed as a part of the registration statement. Statements contained in this prospectus concerning the contents of any contract or any other documents are not necessarily complete. If a contract or document has been

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filed as an exhibit to the registration statement, we refer you to the copy of the contract or document that has been filed as an exhibit and reference thereto is qualified in all respects by the terms of the filed exhibit.

As a result of this offering, we will become subject to the full informational requirements of the Exchange Act. We will fulfill our obligations with respect to such requirements by filing period reports and other information with the SEC. Our SEC filings, including the registration statement and any exhibits and schedules thereto, may be inspected without charge at the Public Reference Room of the SEC at 100 F Street, N.E., Washington, D.C. 20549, and copies of these materials may be obtained from that office after payment of fees prescribed by the SEC. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC maintains a web site that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC at http://www.sec.gov. After this offering, documents filed by us can also be inspected at the offices of the New York Stock Exchange Inc., 20 Broad Street, New York, New York 10002.

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FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements about our business, operations, and industry that involve risks and uncertainties, such as statements regarding our plans, objectives, expectations and intentions. You can identify these forward-looking statements by the use of forward-looking words such as "outlook," "intends," "plans," "estimates," "believes," "expects," "potential," "continues," "may," "will," "should," "seeks," "approximately," "predicts," "anticipates," "foresees," or the negative version of these words or other comparable words and phrases. Any forward-looking statements contained in this prospectus speak only as of the date on which we make it and are based upon our historical performance and on current plans, estimates and expectations. Our future results and financial condition may differ materially from those we currently anticipate as a result of the various factors. Among those factors that could cause actual results to differ materially are:

- availability of cash flow to pay minimum quarterly distribution on our common units;
- access to the necessary capital to fund the capital expenditures required to maintain full productive capacity at our mines;
- adverse or abnormal geologic conditions, which may be unforeseen;
- our ability to develop our existing coal reserves and meet any expected development timeline;
- our ability to produce coal at existing and planned operations;
- delays in the receipt of, failure to receive or revocation of necessary government permits or leases;
- our ability to meet certain provisions in our existing coal supply agreements, enter into new coal supply agreements or extend existing agreements;
- future legislation and changes in regulations or governmental policies or changes in enforcement or interpretations thereof;
- the outcome of pending or future litigation;
- the loss of, or significant reduction in, purchases by our largest customers;
- competition from other fuels, which may affect the economic competitiveness of coal;
- defects in title or loss of any leasehold interests in our properties;
- changes in coal prices or the costs of mining or transporting coal;
- change in consumption patterns by utilities;
- competition both within the coal industry and outside of it;
- the inherent risk of coal mining operations;
- labor availability, relations and other workforce factors;
- the impact of worldwide economic and political conditions;
- volatility in the capital and credit markets;
- customer deferrals of contracted shipments;
- difficulty in obtaining equipment, parts and raw materials;
- major equipment failures;
-

availability, reliability and costs of transportation;

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- delays in moving our longwall equipment;
- transportation interruptions such as floodings or derailments;
- uncertainties in estimating economically recoverable coal reserves;
- customer performance and credit risks;
- the impact of wars and acts of terrorism;
- costs related to government regulation;
- environmental regulations and impact on customers' demand for coal;
- material liabilities from hazardous substances and environmental contamination;
- the unavailability of insurance to cover certain uninsurable environmental risks;
- the contract prices we receive for coal;
- market demand for domestic and foreign coal, electricity and steel;
- the consummation of financing, acquisition or disposition transactions and the effect thereof on our business;
- the impact of our IPO Reorganization;
- our plans and objectives for future operations and the acquisition or development of additional coal reserves or other acquisition opportunities;
- our relationships with, and other conditions affecting, our customers;
- timing of reductions or increases in customer coal inventories;
- long-term coal sales arrangements;
- the number of coal-fired power plants built in the future versus expectations;
- weather conditions or catastrophic weather-related damage;
- earthquakes and other natural disasters;
- changes in energy policy;
- the availability and cost of competing energy resources;
- our ability to obtain services that have otherwise been provided by our sponsor;
- our existing or future indebtedness;
- changes in postretirement benefit and pension obligations;
- our assumptions concerning our reclamation and mine closure obligations;
- our liquidity, results of operations and financial condition; and

- other factors, including those discussed in "Risk Factors."

Before you invest in our common units, you should be aware that the occurrence of the events described above and elsewhere in this prospectus could have a material adverse effect on our business, results of operations and financial position. We undertake no obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

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CANYON FUEL COMPANY, LLC (PREDECESSOR)

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BOWIE RESOURCE PARTNERS LP

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Introduction

Set forth below are the unaudited pro forma condensed consolidated interim balance sheet of Bowie Resource Partners LP as of March 31, 2015 and the unaudited pro forma condensed consolidated interim statement of comprehensive (loss) income of Bowie Resource Partners LP for the three months ended March 31, 2015 and the year ended December 31, 2014. Such pro forma condensed consolidated financial statements are based on the historical financial statements of Canyon Fuel Company, LLC ("CFC"), the predecessor to our partnership for accounting purposes.

Our unaudited pro forma condensed consolidated financial statements present the pro forma effects of the Utah Transaction and the transactions that will occur in conjunction with our initial public offering (the "Offering Transactions"), each, as described below and of the adjustments set forth under the notes hereto. The unaudited pro forma condensed consolidated interim balance sheet as of March 31, 2015 reflects the effects of the Utah Transaction and the Offering Transactions as if they occurred on March 31, 2015 and the unaudited pro forma condensed consolidated statement of comprehensive (loss) income for the three months ended March 31, 2015 and the year ended December 31, 2014 reflects the effects of the Utah Transaction and Offering Transactions as if they occurred on January 1, 2014. We have not made adjustments to give effect to the incremental selling, general and administrative expenses of approximately $ million that we expect to incur as a result of being a publicly traded partnership. The unaudited pro forma condensed consolidated financial statements should be read in conjunction with the historical financial statements included elsewhere in this prospectus.

Our unaudited pro forma condensed consolidated financial statements are based on certain assumptions and do not purport to be indicative of the results that actually would have been achieved if the Utah Transaction and the Offering Transactions had been completed on the dates set forth above. These assumptions are subject to change and the effect of any such change could be material. Moreover, they do not project our financial position or results of operations as of any future date or for any future period.

Pro Forma Condensed Consolidated Interim Balance Sheet

Please read "Note 1. Pro Forma Condensed Consolidated Interim Balance Sheet Adjustments."

The Utah Transaction includes:

- the closing, on June 5, 2015, of the acquisition by Fossil Rock Resources, LLC of certain undeveloped, high Btu, low sulfur coal reserves in Utah from an affiliate of PacifiCorp; and
- the closing, on June 5, 2015, of the acquisition by Hunter Prep Plant, LLC of certain real property near PacifiCorp's Hunter Power Plant.

Neither Fossil Rock Resources, LLC nor Hunter Prep Plant, LLC had a history of operations, nor did they own any assets, until the closing of the Utah Transaction.

The Offering Transactions include:

- CFC will distribute all cash and cash equivalents, including accounts receivable, to Bowie Resource Holdings, LLC ("BRH")
- BRH will transfer or cause to be transferred 100% of the equity interests in (i) CFC, including CFC's subsidiary, Fossil Rock Resources, LLC, and (ii) Hunter Prep Plant, LLC to us in exchange for (a) common units (common units if the underwriters exercise their

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BOWIE RESOURCE PARTNERS LP

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

option to purchase additional common units in full) and subordinated units and (b) the right to receive a cash distribution of up to $ million from us as reimbursement for capital expenditures;

- Our issuance of $ million aggregate principal amount of our % senior secured notes due (the "New Notes");
- Our entry into a new $ million revolving credit facility;
- Our entry into a coal supply agreement with Bowie Coal Sales, LLC, a subsidiary of Bowie Resource Partners, LLC;
- The termination of the existing Coal Services Agreement among CFC, BRH and Trafigura AG and our entry into a new Coal Services Agreement with BRH and Trafigura AG;
- Our entry into an omnibus agreement and certain other agreements with Bowie Resource Partners, LLC and its affiliates;
- The issuance by us to the public of common units; and
- The following use of the net proceeds from the offering and our offering of the New Notes:
  - $ million to make a cash distribution to BRH as reimbursement for capital expenditures incurred by CFC;
  - $ million to repay promissory notes issued by each of Fossil Rock Resources, LLC and Hunter Prep Plant, LLC to PacifiCorp and its affiliate in connection with the Utah Transaction;
  - $ million to repay CFC's outstanding equipment notes with Prudential Insurance Company of America (the "Prudential Notes"); and
  - approximately $ million to pay offering expenses.

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BOWIE RESOURCE PARTNERS LP

Unaudited Pro Forma Condensed Consolidated Interim Balance Sheet as of March 31, 2015

	Canyon Fuel Company, LLC	Adjustments for Utah Transaction (Note 1)	Adjustments for Offering Transactions (Note 1)		Bowie Resource Partners LP Pro Forma
		(in thousands)			
Assets					
Current assets:					
Cash	$ —	$	$	(b)(c)	$
Accounts receivable	15,746			(c)	
Inventories, net	48,588			(e)	
Prepaid expenses and other current assets	16,618			(b)	
Current portion of above market sales contracts	12,423				
Total current assets	93,375				
Property, plant and equipment, including mineral reserves and mine development costs, net	344,557		(a)	(e)	
Restricted cash	3,100				
Above market sales contracts, less current portion	—				
Deferred financing costs, net	9,457			(d)	
Other noncurrent assets	3,646			(a)(e)	
Total Assets	$ 454,135	$	$		$
Liabilities and member's equity					
Current liabilities:					
Accounts payable	$ 28,037	$	$		$
Accrued expenses	21,728				
Current portion of debt and short-term borrowings	50,502			(b)	
Current portion of below market sales contracts	5,538				
Total current liabilities	105,805				
Debt, less current portion	327,976		(a)	(b)(e)	
Asset retirement obligations	9,381		(a)	(e)	
Other noncurrent liabilities	2,907				
Total liabilities	446,069				
Member's equity	8,066		(a)	(c)(d)(e)	
Total liabilities and member's equity	$ 454,135	$	$		$

See accompanying notes to unaudited pro forma condensed consolidated financial statements

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BOWIE RESOURCE PARTNERS LP

Unaudited Pro Forma Condensed Consolidated Interim Statement of Comprehensive (Loss) Income
for the Three Months Ended March 31, 2015

	Canyon Fuel Company, LLC	Adjustments for Offering Transactions (Note 2)	Bowie Resource Partners LP Pro Forma
Revenues:			
Coal sales to non-related parties	$ 45,697	$	$
Coal sales to related parties	58,227		
Other revenues, net	91		
Total revenues	104,015		
Cost of coal sales, exclusive of items shown separately below	74,587		
Purchased coal from related parties	56		
Depreciation, depletion and amortization	21,334		
Amortization of acquired sales contracts, net	(54)		
Selling, general and administrative expenses	4,173	(f)	
Operating income	3,919		
Other expense:			
Interest expense and related financing costs	(8,021)	(g)	
Net (loss) income and comprehensive (loss) income	$ (4,102)	$	$

See accompanying notes to unaudited pro forma condensed consolidated financial statements

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BOWIE RESOURCE PARTNERS LP

Unaudited Pro Forma Condensed Consolidated Statement of Comprehensive (Loss) Income
for the Year Ended December 31, 2014

	Canyon Fuel Company, LLC	Adjustments for Offering Transactions (Note 2)	Bowie Resource Partners LP Pro Forma
		(in thousands)	
Revenues:			
Coal sales to non-related parties	$ 316,944	$	$
Coal sales to related parties	102,860		
Other revenues, net of settlement expenses	358		
Total revenues	420,162		
Cost of coal sales, exclusive of items shown separately below	262,907		
Purchased coal from related parties	15,136		
Depreciation, depletion and amortization	81,057		
Amortization of acquired sales contracts, net	12,098		
Selling, general and administrative expenses	17,590	(f)	
Operating income	31,374		
Other expenses:			
Interest expense and related financing costs	(36,245)	(g)	
Net other expense	(36,245)		
Net (loss) income and comprehensive (loss) income	$ (4,871)	$	$

See accompanying notes to unaudited pro forma condensed consolidated financial statements

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BOWIE RESOURCE PARTNERS LP

NOTES TO UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. Pro Forma Condensed Consolidated Interim Balance Sheet Adjustments

(a) Reflects the pro forma effect of the closing of the Utah Transaction on June 5, 2015, from PacifiCorp and its affiliate of:

(i) certain undeveloped, high Btu, low sulfur coal reserves in Utah by Fossil Rock Resources, LLC in exchange for a $30 million promissory note; and

(ii) certain real property near the Hunter Power Plant by Hunter Prep Plant, LLC in exchange for a $10 million promissory note.

(b) Reflects adjustments relating to the release of CFC as a guarantor under BRH's existing senior secured credit facilities, the issuance of the New Notes and the entry into our new revolving credit facility. The adjustments are based on the following assumptions:

(i) the release of CFC as a guarantor of a total of $ million in debt outstanding under BRH's existing senior secured credit facilities;

(ii) the issuance of $ million aggregate principal amount of New Notes;

(iii) total borrowings of $ million under our new revolving credit facility; and

(iv) total fees relating to our New Notes and our new revolving credit facility of $ million, which will be capitalized.

(c) Reflects adjustments for the Offering Transactions not discussed in Note (b) above. These adjustments are based on the following assumptions:

(i) gross proceeds of $ million from the issuance and sale of common units at an assumed initial offering price of $ per unit (the midpoint of the range set forth on the cover page of this prospectus);

(ii) estimated underwriting fees and commissions and offering expenses of $ million;

(iii) a total cash distribution of $ million to BRH; and

(iv) replenishment of working capital with remaining cash proceeds of $ million.

(d) Reflects adjustments to write off deferred financing costs that relate to BRH's existing senior secured credit facilities.

(e) Reflects the impact of the transfer of 100% of the equity interests of Fossil Rock Resources, LLC and Hunter Prep Plant, LLC.

NOTE 2. Pro Forma Condensed Consolidated Interim Statement of Comprehensive (Loss) Income Adjustments

(f) Reflects the elimination of advisory fees that would not have been paid if we were a publicly traded partnership.

(g) Reflects a decrease in interest expense to reflect a lower effective interest rate associated with our New Notes and our new revolving credit facility, partially offset by higher amortization of deferred financing cost associated with our New Notes and our new revolving credit facility.

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BOWIE RESOURCE PARTNERS LP

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Ernst & Young LLP
Suite 2400
400 West Market Street
Louisville, KY 40202

Tel:+1 314 290 1000
Fax:+1 314 290 1882
ey.com

Report of Independent Registered Public Accounting Firm

The Partners
Bowie Resource Partners LP

We have audited the accompanying consolidated balance sheet of Bowie Resource Partners LP and subsidiary (the Partnership) as of March 31, 2015. The consolidated balance sheet is the responsibility of the Partnership's management. Our responsibility is to express an opinion on this consolidated balance sheet based on our audit.

We conducted our audit in accordance with the standards of the Public Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Partnership's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated balance sheet referred to above presents fairly, in all material respects, the financial position of Bowie Resource Partners LP and subsidiary at March 31, 2015, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Louisville, KY
May 28, 2015

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BOWIE RESOURCE PARTNERS LP

Consolidated Balance Sheet as of March 31, 2015

	March 31, 2015
Assets	$ —
Liabilities and partners' capital	
Total liabilities	—
Partners' capital:	
Limited partners	100
General partner	—
Less: contribution receivable from partners	(100)
Total partners' capital	—
Total liabilities and partners' capital	$ —

See accompanying notes to consolidated balance sheet

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BOWIE RESOURCE PARTNERS LP

NOTES TO CONSOLIDATED BALANCE SHEET

1. Nature of Operations

Bowie Resource Partners LP (the "Partnership") is a Delaware limited partnership formed in January 2015. Bowie GP, LLC (the "General Partner") is a limited liability company formed in January 2015 as the general partner of the Partnership. In January 2015, the Partnership formed its wholly-owned subsidiary BRP Holdings LLC (the "Operating Company").

In January 2015, Bowie Resource Holdings, LLC ("BRH"), a Delaware limited liability company, agreed to contribute $100 to the Partnership in exchange for a 100% limited partner interest. The agreement to contribute has been recorded as a contribution receivable and is reflected in the accompanying balance sheet as a reduction to partners' capital.

There have been no other transactions involving the Partnership or the Operating Company as of May 28, 2015.

The Partnership, pursuant to an initial public offering, intends to sell common units representing limited partnership interests in the Partnership. In connection with the closing of the public offering, BRH will contribute its ownership interests in Canyon Fuel Company, LLC, Fossil Rock Resources, LLC and Hunter Prep Plant, LLC (the "Contributed Assets") to the Partnership, which will then contribute the Contributed Assets to the Operating Company. The Partnership will then issue common units and subordinated units to BRH in exchange for the Contributed Assets and will offer common units to the public by way of a public offering. The General Partner will have a non-economic general partner interest in the Partnership. In addition, the Partnership will issue to the General Partner incentive distribution rights, which entitle the holder to increasing percentages, up to a maximum of 50%, of the distributions the Partnership makes above the highest target level.

The Partnership and the Operating Company, upon transfer of the Contributed Assets and the closing of the initial public offering, will be engaged in substantially the same business and revenue generating activities as the companies forming the Contributed Assets.

2. Basis of Presentation

This balance sheet has been prepared in accordance with accounting principles generally accepted in the United States. Since the Partnership and the Operating Company have had no activity since their inception, separate statements of comprehensive income, changes in partners' equity and cash flows have not been presented.

3. Subsequent Events

The Partnership and the Operating Company evaluated subsequent events occurring through May 28, 2015, which is the date the accompanying financial statements were issued, and has determined that there are no material events that require recognition or disclosure.

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Bowie Resource Partners, LLC

We have audited the accompanying balance sheet of Canyon Fuel Company, LLC (the Company) as of December 31, 2014, and the related statements of operations and comprehensive (loss) income, members' equity and cash flows for the year ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States and in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Canyon Fuel Company, LLC at December 31, 2014, and the results of its operations and its cash flows for the year ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 8 to the financial statements, the Company intends to refinance its Senior Secured Credit Facility. If such refinancing does not occur by the end of the third quarter of 2015, a violation of the financial covenant of the Senior Secured Credit Facility is expected that raises substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 8. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

March 26, 2015

Ernst + Young LLP

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9717 Cogdill Road
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Knoxville, TN 37932

C&J COULTER & JUSTUS, P.C.

phone: (865) 637-4161
fax: (865) 524-2952
web: cj-pc.com

Report of Independent Registered Public Accounting Firm

Board of Directors
Bowie Resource Partners, LLC

We have audited the accompanying balance sheet of Canyon Fuel Company, LLC (the Company) as of December 31, 2013, and the related statements of operations and comprehensive loss, member's equity and cash flows for the period from August 16, 2013 to December 31, 2013. The Company's management is responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Canyon Fuel Company, LLC at December 31, 2013, and the results of its operations and its cash flows for the period from August 16, 2013 to December 31, 2013, in conformity with accounting principles generally accepted in the United States.

Coulter & Justus, P.C.

Knoxville, Tennessee
November 25, 2014

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Building a better working world

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St. Louis, MO 63105

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ey.com

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Bowie Resource Partners, LLC

We have audited the accompanying statements of income and comprehensive income, changes in members' equity, and cash flows for the period from January 1, 2013 to August 16, 2013 of Canyon Fuel Company, LLC (the "Predecessor"). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Predecessor's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Predecessor's internal control over financial reporting. Accordingly we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the results of the Predecessor's operations and its cash flows for the period from January 1, 2013 to August 16, 2013, in conformity with U.S. generally accepted accounting principles.

As described in Note 2 to the financial statements, the accompanying financial statements for the period from January 1, 2013 to August 16, 2013 have been derived from the accounting records of Arch Coal, Inc. These financial statements include expense allocations for certain corporate functions historically provided by Arch Coal, Inc. These allocations may not be reflective of the actual expense which would have been incurred had the Predecessor operated as a separate entity apart from Arch Coal, Inc.

St. Louis, Missouri

April 1, 2014

Ernst + Young LLP

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Canyon Fuel Company, LLC

Balance Sheets

(in thousands)

	December 31,	
	2014	**2013**
Assets		
Current assets:		
Accounts receivable from non-related parties	**$ 10,412**	$ 19,849
Accounts receivable from related party	**—**	414
Inventories, net	**52,375**	33,768
Prepaid expenses and other current assets	**6,992**	6,149
Current portion of above market sales contracts	**14,876**	21,913
Total current assets	**84,655**	82,093
Property, plant and equipment, including mineral reserves and mine development costs, net	**357,110**	400,945
Restricted cash	**3,100**	4,600
Above market sales contracts, less current portion	**867**	15,570
Deferred financing costs, net	**10,024**	12,636
Other noncurrent assets	**3,668**	3,809
Total assets	**$ 459,424**	$ 519,653
Liabilities and member's equity		
Current liabilities:		
Accounts payable	**$ 27,655**	$ 19,911
Accrued expenses	**21,149**	19,982
Current portion of debt and short-term borrowings	**33,151**	41,374
Current portion of below market sales contracts	**8,912**	9,357
Total current liabilities	**90,867**	90,624
Debt, less current portion	**337,179**	383,691
Below market sales contracts, less current portion	**—**	9,197
Asset retirement obligation	**9,175**	8,720
Other noncurrent liabilities	**2,883**	2,795
Total liabilities	**440,104**	495,027
Commitments and contingencies (Note 13)		
Member's equity	**19,320**	24,626
Total liabilities and member's equity	**$ 459,424**	$ 519,653

The accompanying Notes to the Audited Financial Statements are an integral part of these Audited Financial Statements.

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Canyon Fuel Company, LLC

Statements of Operations and Comprehensive (Loss) Income

(in thousands)

		Year Ended December 31, 2013	
	Year Ended December 31, 2014	**Post-Acquisition Period from August 16, 2013 to December 31, 2013**	**Pre-Acquisition Period from January 1, 2013 to August 16, 2013**
Revenues:			
Coal sales to non-related parties	**$ 316,944**	$ 134,626	$ 219,140
Coal sales to related parties	**102,860**	24,130	—
Other revenues, net	**358**	1,410	813
Total revenues	**420,162**	160,166	219,953
Cost of coal sales, exclusive of items shown separately below	**262,907**	115,855	171,720
Purchased coal from related parties	**15,136**	—	—
Depreciation, depletion and amortization	**81,057**	27,251	21,955
Amortization of acquired sales contracts, net	**12,098**	3,708	—
Selling, general and administrative expenses	**17,590**	9,586	7,970
Operating income	**31,374**	3,766	18,308
Other income (expense):			
Interest expense and related financing costs	**(36,245)**	(13,604)	—
Gain on sale of assets	**—**	—	389
Other	**—**	—	(769)
Net other expense	**(36,245)**	(13,604)	(380)
Net (loss) income and comprehensive (loss) income	**$ (4,871)**	$ (9,838)	$ 17,928

The accompanying Notes to the Audited Financial Statements are an integral part of these Audited Financial Statements.

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Canyon Fuel Company, LLC

Statements of Member's Equity

(in thousands)

	Member's Equity
Pre-Acquisition Period from January 1, 2013 to August 16, 2013	
Balance at January 1, 2013	$ 312,438
Net income	17,928
Asset contributed by Arch to be included in sale	1,994
Distribution to parent	(40,807)
Balance at August 16, 2013	291,553
Post-Acquisition	
Balance at August 16, 2013	62,437
Net loss	(9,838)
Net distribution to parent	(27,973)
Balance at December 31, 2013	24,626
Net loss	**(4,871)**
Net distribution to parent	**(435)**
Balance at December 31, 2014	**$ 19,320**

The accompanying Notes to the Audited Financial Statements are an integral part of these Audited Financial Statements.

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Canyon Fuel Company, LLC

Statements of Cash Flows

(in thousands)

		Year Ended December 31, 2013	
	Year Ended December 31, 2014	Post-Acquisition Period from August 16, 2013 to December 31, 2013	Pre-Acquisition Period from January 1, 2013 to August 16, 2013
Operating activities			
Net (loss) income	**$ (4,871)**	$ (9,838)	$ 17,928
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**81,057**	27,251	21,955
Amortization of acquired sales contracts, net	**12,098**	3,708	—
Amortization of discounts on notes payable	**2,310**	690	—
Accretion of asset retirement obligation	**785**	—	462
Amortization of deferred financing costs	**2,612**	862	—
Prepaid royalties expensed	**—**	—	759
Gain on sale of assets	**—**	—	(389)
Changes in operating asset and liabilities:			
Accounts receivable from non-related parties	**9,437**	(19,849)	463
Accounts receivable from related party	**414**	(414)	—
Inventories	**(18,607)**	17,019	9,681
Prepaid expenses and other current assets	**(7,711)**	(5,547)	1,677
Other noncurrent assets	**141**	(144)	142
Accounts payable	**5,604**	12,319	4,996
Accrued expenses	**1,167**	(11,252)	(11,710)
Other noncurrent liabilities	**88**	53	—
Net cash provided by operating activities	**84,524**	14,858	45,964
Investing activities			
Purchases of property, plant and equipment	**(28,544)**	(3,793)	(5,653)
Proceeds from the sale of equipment	**—**	20	639
Additions to prepaid royalties	**—**	—	(203)
Change in restricted cash	**1,500**	(4,600)	—
Net cash used in investing activities	**(27,044)**	(8,373)	(5,217)
Financing activities			
Proceeds from long-term debt and notes payable	**27,449**	44,950	—
Payments on long-term debt and notes payable	**(84,494)**	(23,079)	—
Payments for deferred financing costs	**—**	(383)	—
Net distributions to parent	**(435)**	(27,973)	(40,807)
Net cash used in financing activities	**(57,480)**	(6,485)	(40,807)
Net decrease in cash	**—**	—	(60)
Cash at beginning of period	**—**	—	82
Cash at end of period	**$ —**	$ —	$ 22
Supplemental disclosure of cash flow information			
Cash paid for interest	**$ 35,108**	$ 7,156	$ —
Supplemental disclosure of noncash activities			
Property, plant and equipment financed	**$ —**	$ 30,264	$ —
Property, plant and equipment purchases in accounts payable	**2,142**	—	—

The accompanying Notes to the Audited Financial Statements are an integral part of these Audited Financial Statements.

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Canyon Fuel Company, LLC

Notes to Audited Financial Statements

Years Ended December 31, 2014 and 2013

1. Description of Business

Canyon Fuel Company, LLC (the Company) operates three underground coal mines in Utah (two longwall operations and one room-and-pillar operation) and is wholly-owned by Bowie Resource Holdings, LLC (BRH), an entity that is wholly-owned by Bowie Resource Partners, LLC (BRP).

The Company engages in the extraction, cleaning and marketing of steam coal for sale primarily to major power plants in Utah, Nevada and California, as well as to cement, lime and gypsum plants and other industrial users in the western United States. In addition, the Company has access to port terminals in the State of California through which its coal is exported to a variety of growing international markets.

On August 16, 2013 (Acquisition Date), the Company was acquired (the Acquisition) by BRH from Arch Coal, Inc. and Arch Western Resources, LLC, an entity controlled by Arch Coal (Arch) (Note 3).

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying Financial Statements include the accounts of the Company, as a controlled entity of BRP, for the post-acquisition periods as of December 31, 2014 and December 31, 2013 and the results of operations and cash flows for the year end December 31, 2014 and the period from August 16, 2013 through December 31, 2013. Also included are the accounts of the Company, as a controlled entity of Arch, for the pre-acquisition period from January 1, 2013 to August 16, 2013.

The Financial Statements of the Company have been prepared on the accrual basis of accounting in accordance with accounting principles generally accepted in the United States of America (GAAP) and Staff Accounting Bulletin Topic 1.B, *Allocation of Expenses and Related Disclosure in Financial Statements of Subsidiaries, Divisions or Lesser Business Components of Another Entity*. The Accounting Standards Codification (ASC), as produced by the Financial Accounting Standards Board, is the sole source of authoritative GAAP for non-governmental entities.

The Company has applied push-down accounting effective as of the Acquisition Date. Push-down accounting refers to the establishment of a new accounting and reporting basis for an acquiree (consistent with the purchase accounting basis used by the acquirer) in its separate standalone financial statements. This is based on an acquisition that results in the acquiree's outstanding equity interest becoming substantially wholly-owned. When push-down accounting has been applied, the acquiree's accounting should be substantially similar to that appropriate for a new entity. Accordingly, the Company's accounts were adjusted as of the Acquisition Date to reflect the new equity position of the Company, and the results of operations and cash flows for the year ended December 31, 2013 have been segregated in the accompanying Financial Statements to reflect pre- and post-acquisition activity.

These Financial Statements include allocations of assets, liabilities and expenses related to BRP's and BRH's corporate functions (post-acquisition) and Arch's corporate functions (pre-acquisition), including senior management, operations support, marketing, legal, human resources, finance and information technology. Allocations are based on proportional costs or incremental costs, whichever management has assessed is more representative of the amounts incurred by BRP, BRH or Arch, as applicable, on behalf of the Company. These amounts are allocated on the basis of the number of

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

2. Summary of Significant Accounting Policies (Continued)

Basis of Presentation (Continued)

locations or such other basis as deemed reasonably reflective of the Company's usage of the services provided by these related companies.

Post-acquisition, BRH allocated to the Company long term debt and related deferred financing costs and interest expense. BRH also allocated to the Company certain assets and liabilities attributable to or being utilized by the Company. These accounts include accounts receivable; prepaid expenses and other current assets; capitalized computer hardware and software included in property, plant and equipment, including mineral reserves and mine development costs, net; other noncurrent assets; accounts payable and accrued expenses. Within the Statements of Operations and Comprehensive (Loss) Income, allocations to the Company include amortization of capitalized computer hardware and software costs, reflected in depreciation, depletion and amortization; with all other cost allocations included in selling, general and administrative expenses.

Post-acquisition, the Company secured insurance coverage and bonding under programs maintained by BRH. As a result, the Company's costs under these programs may not reflect the costs it would otherwise incur if it operated as a stand-alone business.

Pre-acquisition, the Financial Statements include an allocation of expenses related to Arch's corporate functions, including senior management, operations support, marketing, legal human resources, finance and information technology. Expenses were allocated on a basis of proportional or incremental costs, whichever management had assessed was more representative of the costs incurred by Arch on behalf of the Company. These costs were allocated on the basis of revenues, headcount, number of locations, or such other basis as deemed reasonably reflective of the Company's usage of the services provided by Arch. These costs are reflected in selling, general and administrative expenses in the statements of operations and comprehensive (loss) income. The Financial Statements also include an allocation of expenses related to Arch Western Bituminous Group's office in Grand Junction, Colorado, including management oversight, engineering, human resources, finance, purchasing and information technology. These costs are reflected in cost of sales in the statements of operations and comprehensive (loss) income. All of the Company's employees are compensated under Arch's incentive and bonus plans, including stock-based awards. The costs, determined under GAAP, directly relating to the employees of the Company's mining complexes are reflected in the Company's cost of coal sales. The costs allocated to the Company are not necessarily indicative of the costs that would have been incurred if the Company were operated as a stand-alone business. See Note 11, Related Party Transactions for a discussion of the Company's various transactions with Arch.

Amounts, except per ton data, presented throughout these Financial Statements are in thousands (000s) of U.S. Dollars, unless otherwise indicated.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect certain reported amounts and disclosures. Accordingly, actual results could differ from those estimates.

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

2. Summary of Significant Accounting Policies (Continued)

Company Environment and Risk Factors

The Company, in the course of its business activities, is exposed to a number of risks including fluctuating market conditions for coal, transportation and fuel costs, changing government regulations, unexpected maintenance and equipment failure, employee benefits cost control, changes in estimates of proven and probable coal reserves, the availability and timing of necessary mining permits and control of adequate recoverable mineral reserves. In addition, adverse weather and geological conditions may increase operating costs, sometimes substantially.

Centralized Treasury Function

For the post-acquisition period covered by these Financial Statements, the Company's treasury activities were centralized at BRH's corporate office in Louisville, Kentucky. The Company's excess cash is remitted to BRH and the Company's disbursement accounts are funded by BRH as amounts are presented for payment. Accordingly, the amounts due to or from BRH and its subsidiaries are primarily settled as a net distribution to parent, and accounts receivable and accounts payable related to these transactions are not recorded. Only minimal cash balances are maintained at the Company level.

Revenue Recognition

The Company's revenues are generated primarily under long-term coal sales contracts with electric utilities, industrial companies and coal brokers that in turn sell coal domestically or internationally. Revenue is recognized when title or risk of loss passes to the customer. Title passes generally when the coal is loaded on the rail, ocean vessel or other transportation source that delivers the coal to its destination.

Other revenues primarily include net revenues from contract termination (bookouts) or restructuring payments incurred during the period. Also included are revenues from royalties related to coal lease agreements and revenues from property and facility rentals.

Shipping and Handling Costs

The Company sells a majority of its coal to customers at delivery points other than its mines, including power plants, industrial facilities and ports along the U.S. West Coast. As such, the Company often bears the transportation costs and any transloading costs. The Company records shipping and handling costs as a component of cost of coal sales.

Cash and Restricted Cash

Cash consists of cash held with reputable depository institutions and is stated at cost, which approximates fair value. Restricted cash consists of amounts held on deposit with bonding agencies to secure bonding obligations.

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

2. Summary of Significant Accounting Policies (Continued)

Accounts Receivable and Allowance for Doubtful Accounts

The Company evaluates accounts receivable based upon the estimated collectability, as determined by such variables as customer creditworthiness, the age of the receivables and historical loss experience. Receivables are considered past due if the full payment is not received by the contractual due date. Account balances are charged off after all means of collection have been exhausted and the potential for recovery is considered remote. It is the Company's policy not to require collateral on accounts receivable. Based upon the Company's evaluation, there was no allowance for doubtful accounts at December 31, 2014 or 2013. The Company does not have a history of credit losses with its customers.

Inventories

Coal, parts and supplies inventories are valued at the lower of average cost or market. Coal inventory costs include labor, parts and supplies used, equipment costs, transportation costs prior to title transfer to customers, depreciation, depletion, amortization and operating overhead. Coal is classified as inventory at the time the coal is extracted and transported to the mine surface.

Longwall Costs

Longwall mining is a form of underground mining that employs a shearer with two rotating drums pulled mechanically back and forth across an exposed coal face. The roof of the mine is supported by a hydraulic system while the drums are mining the coal. Conveyors move the loosened coal to an underground mine conveyor which transports the coal to the mine surface. The process to move the longwall shearer to a new coal panel within the mine occurs over the course of several months. Costs of relocating a longwall shearer to a new coal panel are capitalized and amortized using the straight-line method over the estimated life of the new coal panel. Costs capitalized include labor, parts and supplies used, and other equipment costs incurred to reposition a longwall shearer. Capitalized longwall costs are included in prepaid expenses and other current assets in the accompanying Balance Sheets. The Company had $4,083 recorded as capitalized longwall costs as of December 31, 2014. Capitalized longwall costs were not significant as of December 31, 2013. Amortization of capitalized longwall costs was $6,868 for the year ended December 31, 2014. Amortization of capitalized longwall costs was not significant during the post-acquisition period from August 16, 2013 to December 31, 2013 or the pre-acquisition period from January 1, 2013 to August 16, 2013.

Property, Plant and Equipment

Property, plant and equipment are stated at cost, except for assets acquired using purchase accounting, which are recorded at fair value at the date of acquisition. Additions and improvements that significantly add to productive capacity or extend the useful life of assets are capitalized. Interest costs applicable to major asset additions are capitalized during the construction period. Maintenance and repair costs are expensed as incurred. Depreciation is recorded using the straight-line method over the estimated useful lives of the assets. The useful lives of the Company's equipment, plant and facilities generally range from 5 to 10 years with the exception of buildings, which have a 20 year useful life.

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

2. Summary of Significant Accounting Policies (Continued)

Property, Plant and Equipment (Continued)

Mineral rights and mine development costs, which are included with property, plant and equipment, are recorded at cost, except for assets acquired using purchase accounting, which are recorded at fair value at the date of acquisition. If coal is extracted during the mine development process, the amount of revenue from the sale of that coal is credited against the costs of development. Depletion of reserves and amortization of mine development costs are computed using the units of production method, based on estimated proven and probable reserves.

Long-lived assets, such as property, equipment, mine development costs, owned and leased mineral rights and purchased intangibles subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or asset groups may not be recoverable. Recoverability of assets or asset groups to be held and used is measured by a comparison of the carrying amount of an asset or asset group to the estimated undiscounted future cash flows expected to be generated by the asset or asset group. If the carrying amount of an asset or asset group exceeds its estimated future cash flows, an impairment charge is recognized equal to the amount by which the carrying amount of the asset or asset group exceeds the fair value of the asset or asset group.

Acquired Sales Contracts

Coal supply agreements (sales contracts) acquired in business combinations are capitalized at their fair value and amortized over the tons of coal shipped during the contract. The fair value of a sales contract is determined by discounting the cash flows attributable to the difference between the contract price and the prevailing forward prices for the tons remaining under the contract at the date of acquisition. Contracts where the expected contract price is above market at the acquisition date are classified as assets, whereas contracts where the expected contract price is below market at the acquisition date are classified as liabilities. If a contract is terminated before it has been fully amortized, the remaining fair value of the acquired contract is written off and recognized as a gain (below market contracts) or loss (above market contracts) on contract termination.

In conjunction with the Acquisition (Note 3), the Company recorded above market sales contracts with a fair value of $49,138 and below market sales contracts with a fair value of $26,501 in the opening balance sheet. The contracts are amortized over a weighted average amortization period of approximately 3 years.

Net amortization expense of the Company's acquired contracts was $12,098 and $3,708 for the year ended December 31, 2014 and for the post-acquisition period from August 16, 2013 to December 31, 2013, respectively. The Company did not have acquired sales contracts during the pre-acquisition period from January 1, 2013 to August 16, 2013.

Based on expected remaining shipments under these contracts, the Company estimates the following net amortization for the years ended December 31:

2015	**$ 5,964**
2016	**867**
Total	**$ 6,831**

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

2. Summary of Significant Accounting Policies (Continued)

Income Taxes

The Company is a single member limited liability company that is treated as a disregarded entity for federal and state income tax purposes. The Company's parent has elected to be treated as a partnership for federal and state income tax purposes. A partnership is not a tax paying entity for federal and state income tax purposes. Income, loss, deductions and credits of the Company pass through to its member and are taxed at the member's income tax rate. Accordingly, no provision for income taxes is provided in these Financial Statements. The Company reports any tax-related interest and penalties as a component of other expense. The Company makes distributions to its member to cover the member's estimated state and federal income taxes payable as a result of the operations of the Company.

The Company does not believe there are any material uncertain tax positions and, accordingly, it did not recognize a liability for unrecognized benefits in the Balance Sheets at December 31, 2014 and 2013. The Company does not anticipate any significant change in unrecognized tax benefits during the next twelve months.

The Company remains open to state examinations for tax years ended December 31, 2013 to December 31, 2014. The Company is not currently under examination by the Internal Revenue Service, state or local tax authorities.

Advance Royalties

The Company is required, under certain royalty lease agreements, to make minimum royalty payments whether or not mining activity is performed on the leased property. These minimum payments may be recoupable once mining begins on the leased property. The Company capitalizes the recoupable minimum royalty payments and amortizes these deferred costs, once the mining activities begin, on the units of production method. If the Company has ceased mining or has made a decision not to mine such property, these deferred costs are expensed.

Deferred Financing Costs

Deferred financing costs represent capitalized amounts paid in connection with the issuance of debt. These costs are amortized using the effective interest method over the term of the associated debt.

Asset Retirement Obligations

The Company's asset retirement obligation (ARO) liabilities consist of cost estimates for reclamation and support facilities at mines in accordance with interpretations of applicable state and federal reclamation laws, as defined by each mining permit. These cost estimates relate to reclaiming support acreage, sealing portals at deep mines and other costs related to reclaiming refuse areas.

The Company estimates its ARO liabilities for final reclamation and mine closure based upon detailed engineering calculations of the amount and timing of the future cash spending for a third-party to perform the required work. Cost estimates are escalated for inflation and then discounted at a credit-adjusted risk-free rate (9.00% at December 31, 2014 and 2013). Accretion on the ARO begins at

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

2. Summary of Significant Accounting Policies (Continued)

Asset Retirement Obligations (Continued)

the time the liability is incurred. Upon initial recognition of a liability, a corresponding amount is capitalized as part of the carrying amount of the related long-lived asset. The ARO asset is amortized over its expected life on a units-of-production basis. The ARO liability is then accreted to the projected spending date. As changes in estimates occur (such as mine plan revisions, changes in estimated costs, or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free rate. The Company reviews its asset retirement obligation at least annually and makes necessary adjustments for permit changes as granted by state authorities and for revisions of estimates of the amount and timing of costs. Any difference between the recorded obligation and the actual cost of reclamation is recorded in profit or loss in the period the obligation is settled.

Exploratory Costs

Costs to acquire permits for exploration activities are capitalized. Drilling and other costs related to locating coal deposits and evaluating the economic viability of such deposits are expensed as incurred.

Workers' Compensation Benefits and Pneumoconiosis (Black Lung) Benefits

The Company is subject to federal and state laws to provide workers' compensation and coal workers' black lung benefits to eligible employees, former employees and their dependents. The Company utilizes an insurance program to secure its on-going obligations associated with claims for work-related injuries and occupational disease, including black lung claims, with the exception of black lung claims filed under the Federal Coal Mine Health and Safety Act by former employees of the Company having dates of loss (i.e. the last date of exposure) prior to the Acquisition Date (Note 10), for which the Company is self-insured.

It is the intent of the Company to maintain insurance policies for workers' compensation and black lung related to active employees in order to mitigate its exposure to such claims both now and in the future. Premium expense for workers' compensation benefits is recognized in the period in which the related insurance coverage is provided.

The Company's black lung benefits liability for active employees with dates of loss subsequent to the Acquisition Date is calculated using the service cost method that considers the calculation of the actuarial present value of the estimated black lung obligation. The actuarial calculations using the service cost method for the black lung benefits liability are based on numerous assumptions, including disability incidence, medical costs, mortality, death benefits, dependents and interest rates.

The Company's black lung self-insured liability for black lung claims of employees with dates of loss prior to the Acquisition Date is calculated on an event driven basis that considers actuarial estimates of the aggregate liability for claims incurred. The actuarial calculations are based on numerous assumptions, including disability incidence, medical costs, mortality, death benefits, dependents and interest rates.

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

2. Summary of Significant Accounting Policies (Continued)

Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Valuation techniques used must maximize the use of observable inputs and minimize the use of unobservable inputs.

A three level hierarchy has been established for valuing assets and liabilities based on how transparent (observable) the inputs are that are used to determine fair value, with the inputs considered most observable categorized as Level 1 and those that are least observable categorized as Level 3. Hierarchy levels are defined below:

Level 1: Quoted prices in active markets for identical assets and liabilities;

Level 2: Quoted prices for similar assets and liabilities in active markets; quoted prices for identical or similar instruments in markets that are not active; and

Level 3: Unobservable inputs that are supported by little or no market data which require the reporting entity to develop its own assumptions.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of assets and liabilities and their placement within the fair value hierarchy levels.

The Company's accounts receivable, restricted cash, accounts payable and accrued expenses are considered financial instruments. These assets and liabilities are reflected at fair value or at carrying amounts that approximate their fair value due to the short-term nature or the terms of the instruments. The estimated carrying value of the Company's debt approximates its fair value because the effective interest rates are not significantly different from current market rates. The Company does not have any nonfinancial assets or nonfinancial liabilities measured at fair value on a recurring basis, other than ARO. The inputs and techniques used to derive ARO fair value are described in the Asset Retirement Obligations section of this note. This fair value determination is classified as Level 3 in the hierarchy.

The Company measures the fair value of certain assets on a non-recurring basis, generally when events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. The Company's policy is further described in the property, plant and equipment policies above.

Recently Issued Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued *Accounting Standards Update No. 2014-09: Revenue from Contracts with Customers*. The standard outlines a five-step model for revenue recognition with the core principle being that a company should recognize revenue when it transfers control of goods or services to customers at an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. Companies can choose to apply the standard using the full retrospective approach or a modified retrospective approach. Under the modified approach, financial statements will be prepared for the year of adoption using the new

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

2. Summary of Significant Accounting Policies (Continued)

Recently Issued Accounting Pronouncements (Continued)

standard and prior periods presented will not be adjusted. Companies will recognize a cumulative catch-up adjustment to the opening balance of retained earnings. For public entities, this new guidance is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. For nonpublic entities, this new guidance is effective for annual reporting periods beginning after December 15, 2017, and interim reporting periods within annual reporting periods beginning after December 15, 2018. Early adoption is permitted for nonpublic entities. The Company has not yet made a determination as to whether it will early adopt the provisions of this new standard nor has any determination been made as to the method of application (full retrospective or modified retrospective). It is too early to assess whether the impact of the adoption of this new guidance will have a material impact on the Company's results of operations, financial position or cash flows.

The Company does not expect the adoption of any other recently issued accounting pronouncements to have a material impact on its Financial Statements.

Subsequent Events

In preparation of the accompanying Financial Statements, management has evaluated events that have occurred subsequent to the balance sheet date through March 26, 2015, the date the Financial Statements were issued.

Revisions

Subsequent to the issuance of the Company's Financial Statements as of December 31, 2013 and the post-acquisition period from August 16, 2013 to December 31, 2013, a determination was made that the Company's black lung benefits liability was not calculated and reported using the service cost method that considers the calculation of the actuarial present value of the estimated black lung obligation, as required. The Company had accounted for its black lung benefits liability using an event driven approach under ASC 450, *Contingencies*. It was determined the Company should have accounted for its black lung benefits liability using a service cost approach under ASC 710, *Compensation—General*, because this approach matches black lung costs over the service lives of the miners who ultimately receive black lung benefits. The Company also determined that mineral reserves were not recorded at fair value. As of the Acquisition Date, these corrections resulted in an increase in property, plant and equipment, including mineral reserves and mine development costs, net and an increase in other noncurrent liabilities of $1,489, all of which the Company deemed immaterial.

Subsequent to the issuance of the Company's Financial Statements as of December 31, 2013 and the post-acquisition period from August 16, 2013 to December 31, 2013, a determination was made that the calculation of depletion included uncontrolled resources within the depletion base. The uncontrolled resources did not meet the definition of proven and probable reserves in accordance with SEC Industry Guide 7 and should not have been included in the depletion base.

All prior period information has been revised for these items. As of December 31, 2013, the corrections resulted in a net increase in property, plant and equipment, including mineral reserves and mine development costs, net of $502, an increase in other noncurrent liabilities of $1,542 and an

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Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

2. Summary of Significant Accounting Policies (Continued)

Revisions (Continued)

increase to accumulated deficit of $1,040. For the post-acquisition period from August 16, 2013 to December 31, 2013, the corrections resulted in an increase to depletion expense on mineral reserves of $987; an increase in cost of coal sales of $53, and an increase to net loss of $1,040.

The Company has determined these misstatements were not material to the Company's previously issued Financial Statements and has corrected these items by revising the amounts previously reported in the 2013 Financial Statements.

3. Acquisition of Business

On August 16, 2013, BRH acquired 100% of the membership interests in the Company from Arch for $435,000. The Acquisition was funded using proceeds from a cash equity investment in BRH and borrowings under new debt issued by Morgan Stanley Senior Funding Inc. and Deutsche Bank Securities, Inc. (Note 8). The purchase price of the Company consisted of the following items:

Cash consideration for membership interest	$ 435,000
Purchase price adjustment and retained inventory	(12,327)
Total consideration for membership interest	422,673
Credit agreed to for software licenses	(300)
Net consideration transferred	$ 422,373

The Unit Purchase Agreement (Purchase Agreement) specified a base purchase price of $435,000 which was the agreed upon sales price for 100% of the membership interests in the Company. Provisions of the Purchase Agreement allowed for various adjustments to the base purchase price, including a cash adjustment, a debt adjustment, a working capital adjustment and an accounts payable adjustment, which are customary in transactions of this nature. The Company's cash, debt, working capital and accounts payable positions as of the Acquisition Date resulted in a $12,015 reduction in the purchase price. Additionally, per the terms of the Purchase Agreement, the purchase price was reduced by the value of certain coal inventory being retained by Arch. As a result, consideration transferred was reduced by an additional $312 on the Acquisition Date. Consideration transferred was further reduced due to the inability of Arch to transfer certain software licenses following the change in ownership of the Company. BRH had to establish new licenses post acquisition directly with the software vendor. As a result, Arch agreed to an additional $300 reduction in consideration transferred to compensate for the license purchases. Net consideration transferred to Arch on the Acquisition Date was $422,373.

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Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

3. Acquisition of Business (Continued)

The following table summarizes the fair values of the assets acquired and liabilities assumed (prior to the allocations) as of August 16, 2013:

	As Revised(1)
Inventories, net	$ 50,787
Prepaid expenses and other current assets	602
Property, plant and equipment, including mineral reserves and mine development costs	394,159
Above market sales contracts	49,138
Other noncurrent assets	5,017
Accounts payable	(7,592)
Accrued expenses	(30,398)
Long-term debt	(1,377)
Below market sales contracts	(26,501)
Asset retirement obligations	(8,720)
Other noncurrent liabilities	(2,742)
Net consideration transferred	$ 422,373

(1) Amounts previously reported in the 2013 Financial Statements have been revised by $1,489 between (i) property, plant and equipment, including mineral reserves and mine development costs, net and (ii) other noncurrent liabilities as a result of the misstatement in the fair value of the Company's black lung benefits liability.

Fair values for prepaid expenses and other current assets, other noncurrent assets, accounts payable, accrued expenses, long-term debt and other noncurrent liabilities were assumed to approximate their carrying value as stated on the closing trial balance received from Arch as of the Acquisition Date due to the short-term nature of these items or because the effective interest rates were not significantly different from current market rates.

The Company had approximately 1.8 million tons of extracted coal on the Acquisition Date as determined via independent third party surveys performed near the Acquisition Date. The fair value of this acquired coal inventory was determined by the Company using the comparative sales method. Fair value of acquired inventories were estimated to be $40,156 on the Acquisition Date. The Company also had parts and supplies inventories with a fair value of $10,631, net of a reserve for slow-moving and obsolete parts and supplies of $760. The fair value was determined based on the short-term nature of the inventories and a review of the parts and supplies inventories expected to be used in production.

The fair values of acquired property, plant and equipment (PP&E), including mine development costs, were estimated using a combination of the cost and market approaches, depending on the component. The Company engaged independent, third party valuation specialists familiar with the industry to aid in determining the acquisition date fair values of the acquired PP&E. Total PP&E, excluding mineral reserves, was estimated to have a fair value of $345,971 as of the Acquisition Date. Additionally, the Company reconsidered the remaining useful lives of the acquired PP&E and assigned new remaining useful lives, for purposes of calculating depreciation expense, based on a weighted

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

3. Acquisition of Business (Continued)

average of the remaining policy life (based on the Company's fixed asset policy) for each PP&E category. Useful lives assigned range from 3 to 20 years, depending on the asset category. The fair value of acquired mineral reserves, which is included in PP&E, including mineral reserves and mine development costs, was estimated considering both the cash flows for a mining asset's potential reserves beyond proven and probable reserves and estimates of future market price changes. A third party valuation specialist was also engaged by the Company to assist in these fair value estimates. Mineral reserves were estimated to have an Acquisition Date fair value of $46,699. In 2014, a revision (Note 2) of $1,489 to other noncurrent liabilities resulted in an increase in the mineral rights balance to $48,188 within the opening balance sheet and within the December 31, 2013 Balance Sheet.

The Company recognized a liability for ARO associated with the Company's underground mines and coal handling facilities. The Company engaged a third party valuation specialist to estimate the "minimum," "most likely," and "maximum" reclamation costs to be incurred. The Company recorded ARO of $8,720 based on the "most likely" ARO scenario. Because the estimated costs are based on probabilities, the actual liability may be above or below the "most likely" costs recorded.

A third party actuary was also engaged by the Company to assist in determining the fair value associated with the Company's assumed liability for future black lung claims filed under the Federal Coal Mine Health and Safety Act. Initially, the actuary was engaged to calculate a liability in relation to claims filed by Company employees prior to the Acquisition Date. The liability was estimated on an event driven approach, using various actuarial assumptions, including interest rate, for the amount of $1,253 as of the Acquisition Date. Additionally, it was determined that the Company also has a liability for future black lung claims related to active employees with dates of loss subsequent to the Acquisition Date and, therefore, the Company needed to increase its estimate for black lung benefits liability (Note 10). The black lung benefits liability for active employees with dates of loss subsequent to the Acquisition Date was calculated using the service cost method in consideration of the calculation of actuarial present value of the estimated black lung obligation. The revision (Note 2) resulted in a $1,489 reclassification from mineral reserves to increase the fair value estimate for black lung benefits liability (Note 10) to $2,742, included in other noncurrent liabilities within the opening balance sheet on August 16, 2013.

The Company evaluated identified intangible assets and identified the following: (a) the assembled workforce; and (b) customer contracts. The Company used the cost approach to estimate fair values for the assembled workforce. Amounts estimated for the assembled workforce were deemed insignificant for recognition.

Acquired customer contracts were evaluated for favorable and unfavorable terms in accordance with the off-market valuation approach. Terms of the acquired customer contracts were compared with current market terms. As a result, the Company determined acquired contracts contained both favorable and unfavorable terms compared to current market conditions. The Company recognized an intangible asset acquired (for favorable contracts) of $49,138. The Company also assumed a liability for unfavorable contracts which had an estimated fair value of $26,501 as of the Acquisition Date. The useful lives assigned to the acquired contracts were determined in accordance with the duration of the underlying contracts.

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Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

4. Inventories

Inventories consist of the following as of December 31:

	2014	2013
Coal	**$ 40,415**	$ 23,203
Parts and supplies, net of allowance	**11,960**	10,565
Total inventories, net	**$ 52,375**	$ 33,768

Parts and supplies inventories are stated net of an allowance for slow-moving and obsolete inventories of $853 and $821 at December 31, 2014 and 2013, respectively.

5. Prepaid Expenses and Other Current Assets

Prepaid expenses and other current assets consist of the following as of December 31:

	2014	2013
Prepaid insurance	**$ 2,562**	$ 5,942
Longwall costs, net	**4,083**	—
Other	**347**	207
Total prepaid expenses and other current assets	**$ 6,992**	$ 6,149

6. Property, Plant and Equipment

Property, plant and equipment, including mineral reserves and mine development costs, consist of the following as of December 31:

	2014	2013
Mining and other equipment	**$ 318,480**	$ 295,125
Mineral reserves	**47,372**	48,188
Mine development costs	**55,042**	54,329
Land and buildings	**28,964**	27,754
Capitalized asset retirement costs	**485**	—
Construction in progress	**8,617**	2,800
	458,960	428,196
Less accumulated depreciation, depletion and amortization	**101,850**	27,251
Net property, plant and equipment	**$ 357,110**	$ 400,945

Depreciation expense for the Company was $62,746 for the year ended December 31, 2014, $23,469 for the post-acquisition period from August 16, 2013 to December 31, 2013 and $19,236 for the pre-acquisition period from January 1, 2013 to August 16, 2013. Depletion and amortization expense on mineral reserves, mine development costs and capitalized asset retirement costs was $11,443 for the year ended December 31, 2014, $3,782 for the post-acquisition period from August 16, 2013 to December 31, 2013 and $2,719 for the pre-acquisition period from January 1, 2013 to August 16, 2013. Depreciation, depletion and amortization commences upon in service date. Capitalized revenues from coal sold during the mine development process were not significant for the pre-acquisition period from January 1, 2013 to August 16, 2013.

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Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

7. Accrued Expenses

Accrued expenses consist of the following as of December 31:

	2014	2013
Accrued payroll, vacation and related expenses	**$ 7,376**	$ 4,914
Accrued property and production taxes	**3,485**	2,727
Accrued interest on debt and other borrowings	**1,111**	4,896
Other general liabilities	**6,829**	3,759
Freight payable	**741**	2,980
Health insurance plan reserve	**1,607**	706
Total accrued expenses	**$ 21,149**	$ 19,982

8. Debt

The Company's total indebtedness consisted of the following as of December 31:

	2014	2013
2013 Senior Secured Credit Facility, net	**$ 329,476**	$ 370,814
Notes payable to Sevier Special Service District #1	**28,387**	30,264
Notes payable to Prudential Insurance Company of America	**12,467**	19,267
Notes payable to Imperial Premium Financing Specialists	**—**	4,720
Total indebtedness	**370,330**	425,065
Less current portion	**33,151**	41,374
Long-term debt	**$ 337,179**	$ 383,691

The carrying amount of the 2013 Senior Secured Credit Facility is presented above net of the respective unamortized original issue discount (including amounts allocated from BRH) of $9,047 and $11,358 at December 31, 2014 and 2013, respectively.

2013 Senior Secured Credit Facility

On August 16, 2013, BRH entered into loan agreements (collectively, the 2013 Senior Secured Credit Facility) among BRH and its subsidiaries (including the Company), Morgan Stanley Senior Funding Inc. (Morgan Stanley), Deutsche Bank Securities, Inc. (Deutsche Bank), and other lenders thereto. The 2013 Senior Secured Credit Facility provides for a $35,000 senior secured asset-backed revolving credit facility (the 2013 ABL), a $335,000 senior secured first lien term loan (the 2013 First Lien Term Loan), and a $100,000 senior secured second lien term loan (the 2013 Second Lien Term Loan). The 2013 ABL also has provisions for swingline loans up to an additional $5,000. The 2013 First Lien Term Loan and 2013 Second Lien Term Loan (collectively, the 2013 Term Loans) are net of original issue discounts of $10,050 and $4,000, respectively. These discounts are amortized over the lives of the respective term loans. The 2013 ABL has a term of 5 years and will mature on August 16, 2018. The 2013 First Lien Term Loan matures on August 16, 2020 and the 2013 Second Lien Term Loan matures on August 16, 2021. BRH recorded capitalized deferred financing costs of $15,294 related to the 2013 Senior Secured Credit Facility which are being amortized over the weighted average term of

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

8. Debt (Continued)

2013 Senior Secured Credit Facility (Continued)

the 2013 Senior Secured Credit Facility, or 6.5 years. Unamortized deferred financing costs allocated to the Company were $9,833 and $12,341 as of December 31, 2014 and 2013, respectively.

Proceeds from the 2013 Senior Secured Credit Facility were used to finance the Acquisition (Note 3) and to pay for Acquisition related expenses.

The obligations under the 2013 Senior Secured Credit Facility are guaranteed by the subsidiaries of BRH, including the Company. The obligations are also secured by all of the membership units of BRH and substantially all of the assets of the Company.

All borrowings under the 2013 Senior Secured Credit Facility bear interest, at the option of BRH, at either a base rate (subject to a floor of 2.00% for borrowings under the 2013 Term Loans) or a LIBOR rate (subject to a floor of 1.00% for borrowings under the 2013 Term Loans), each as defined in the 2013 Senior Secured Credit Facility, plus: (1) in the case of the 2013 First Lien Term Loan, a margin of 4.75% and 5.75% per year for borrowings bearing interest at the base rate and LIBOR rate, respectively; (2) in the case of the 2013 Second Lien Term Loan, a margin of 9.75% and 10.75% per year for borrowings bearing interest at the base rate and LIBOR rate, respectively; or (3) in the case of the 2013 ABL, a margin dependent on the average historical excess availability, as defined in the 2013 ABL, ranging from 0.75% to 1.00% and 1.75% to 2.00% per year for borrowings bearing interest at the base rate and LIBOR rate, respectively.

BRH had $304,483 and $321,361 outstanding under the 2013 First Lien Term Loan as of December 31, 2014 and 2013, respectively (net of unamortized original discounts of $7,486 and $9,452, as of December 31, 2014 and 2013 respectively). Additionally, BRH had $74,935 and $96,206 outstanding under the 2013 Second Lien Term Loan as of December 31, 2014 and 2013, respectively (net of an unamortized original issue discount of $3,065 and $3,794 as of December 31, 2014 and 2013, respectively). Amounts allocated to the Company by BRH for the 2013 First Lien were $261,094 and $275,567 as of December 31, 2014 and 2013, respectively (net of allocated, unamortized original issue discounts of $6,419 and $8,105 as of December 31, 2014 and 2013, respectively). BRH allocated $64,257 and $82,497 to the Company for the 2013 Second Lien Term Loan as of December 31, 2014 and 2013, respectively (net of allocated, unamortized original issue discounts of $2,628 and $3,253, as of December 31, 2014 and 2013, respectively). Interest rates payable as of December 31, 2014 and 2013 were LIBOR (with a floor of 1.00%) plus: (1) in the case of the 2013 First Lien Term Loan 5.75%, or 6.75% in total; and (2) in the case of the 2013 Second Lien Term Loan 10.75%, or 11.75% in total. The 2013 First Lien Term Loan is also subject to quarterly amortization of escalating rates ranging from 1.25% to 2.50% which commenced on August 16, 2013. Annual principal repayment by BRH for the year ending December 31, 2015 is expected to be $25,125.

The 2013 Term Loans are subject to mandatory prepayment requirements to prepay the term loan borrowings thereunder with proceeds from asset dispositions or property loss events, other debt issuances, and excess cash flow after the end of each fiscal year. These prepayment requirements are subject to various thresholds as defined in the 2013 Senior Secured Credit Facility. The 2013 Term Loans are also subject to various prepayment penalties for voluntary prepayments of principal, in part or in whole, as defined in the 2013 Senior Secured Credit Facility. During 2014, BRH paid $22,000 towards the 2013 Second Lien Term Loan as a result of these provisions.

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

8. Debt (Continued)

2013 Senior Secured Credit Facility (Continued)

Under the 2013 Senior Secured Credit Facility, BRH must comply with one financial covenant on a quarterly basis, which is the maximum senior secured leverage ratio for which the maximum ratio could not exceed 3.5 to 1 as of December 31, 2014 or 4.5 to 1 as of December 31, 2013. BRH was in compliance with this covenant as of December 31, 2014 and 2013.

In 2015, BRH intends to refinance its obligations under the 2013 Senior Secured Credit Facility. If such refinancing does not occur by the end of the third quarter of 2015, BRH does not expect to be in compliance with the maximum senior secured leverage ratio, in which case BRH intends to exercise its ability to Cure, as defined in the 2013 Senior Secured Credit Facility. BRH may not be successful in its refinancing efforts or may not be able to Cure the maximum senior secured leverage ratio breach, which would result in an event of default as defined in the 2013 Senior Secured Credit Facility. These Financial Statements are prepared assuming the Company will continue as a going concern and do not include any adjustments that might result from the outcome of this uncertainty.

BRH is permitted to make distributions, within certain thresholds as defined in the documentation and to buy and sell assets when in compliance with its financial covenants. The 2013 Senior Secured Credit Facility also imposes certain restrictions on the ability of BRH and its subsidiaries to incur liens, incur debt, make investments (including acquisitions), engage in organizational changes such as mergers and dissolutions, dispose of assets, change the nature of its business, enter into transactions with affiliates, and make restricted payments within defined thresholds. It also contains customary events of default. The documentation generally does not restrict BRH's ability to provide for loans and advances between BRH and its subsidiaries that secure or guarantee related indebtedness, provided that certain of such loans and advances are subordinated to BRH's obligations under the 2013 Senior Secured Credit Facility.

The 2013 ABL requires compliance with an additional financial covenant, the fixed charge coverage ratio, upon the occurrence and during the continuation of a covenant trigger period, as defined in the 2013 ABL. BRH was not in a covenant trigger period at any point during 2014. In addition, the agreement requires submission of a monthly borrowing base calculation and certificate to determine net availability under the 2013 ABL. As of December 31, 2014 and 2013, respectively, BRH had $5,500 and $17,000 in outstanding borrowings under the 2013 ABL and the remaining availability was $29,500 and $18,000, as of December 31, 2014 and 2013, respectively. The Company's allocated potions of outstanding borrowings under the 2013 ABL were $4,125 and $12,750 as of December 31, 2014 and 2013, respectively. The interest rates payable on the ABL at December 31, 2014 were LIBOR plus 2.00%, or 2.16% for the first $5,000 and the base rate of 3.25% plus 1.00%, or 4.25%, on the remaining $500. The interest rate payable at December 31, 2013 was LIBOR plus 1.75%, or 1.92%.

Notes Payable to Sevier Special Service District #1

In 2012, the Company entered into an agreement with the State of Utah for the construction of a paved county road (the Quitchupah Road) to shorten its transportation routes from the Sufco mine (Sufco) to one of Sufco's largest customers. The Quitchupah Road project was funded by the Company through the issuance of County Municipal Financing Bonds (the Bonds) with Sevier County, Utah (Sevier Special Service District #1 or Sevier). The Company agreed to repay Sevier for the cost of the

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

8. Debt (Continued)

Notes Payable to Sevier Special Service District #1 (Continued)

road with repayments to begin once construction was complete. Construction on the Quitchupah Road project was ongoing at the time of the Acquisition (Note 3), thus the liability to Sevier and the rights to the Quitchupah Road were acquired by BRH. The amounts owed to Sevier Special Service District #1 are comprised of a $29,935 Repayment Agreement for construction of the Quitchupah Road and a $1,352 Promissory Note for reimbursement of road improvement costs incurred prior to the start of the Quitchupah Road project. The Promissory Note matures on March 1, 2018 and incurs interest at 2.50% annually and is payable in arrears. Principal and interest on the Promissory Note are payable in five equal annual installments of $293 beginning on March 1, 2014. The Repayment Agreement matures on March 1, 2027 and incurs interest at 2.40% annually. Principal and interest payments for the Repayment Agreement commenced on March 1, 2014 and are payable in 14 annual installments of varying amounts as specified in the Repayment Agreement.

The Quitchupah Road project had a total estimated construction cost of $29,935 including costs incurred to obtain funding such as legal fees, cost of all engineering and design work, and costs incurred for permitting, materials, labor and construction required to complete the project. Provisions of the Repayment Agreement allowed for adjustment of the principal amount following submission of a completion report stating actual Quitchupah Road construction costs. The Quitchupah Road was completed in October 2013 and the Company received the final completion report from Sevier Special Service District #1 in February 2014. Actual costs to complete the project were $28,912, $1,023 lower than the estimated cost. In accordance with the Repayment Agreement, the difference between the amount funded and actual project costs incurred was applied as credit against the annual payments due, starting in reverse order with the final annual payment. As such, the Company reduced the principal amount owed to Sevier by $1,023 to $28,912 in December 2013. As of December 31, 2014 and 2013, respectively, the Company had $28,387 and $30,264 outstanding under the notes payable to Sevier Special Service District #1.

Notes Payable to Prudential Insurance Company of America

The Company had outstanding equipment notes totaling $12,467 and $19,267 with Prudential Insurance Company of America as of December 31, 2014 and 2013, respectively. The notes bear interest at a fixed annual rate of 6.10% and are due in various monthly installments through 2016. The notes are secured by liens on the related equipment. The Company recorded $312 of capitalized deferred financing costs related to these notes during 2013 which are being amortized over the term of the notes. Unamortized deferred financing costs approximated $191 and $295 as of December 31, 2014 and 2013, respectively.

Notes Payable to Imperial Premium Financing Specialists

In February 2014, BRH financed a new insurance premium for its workers' compensation insurance policy that had a cost of $7,614. The note incurred interest at 3.97% with monthly payments of $645. As of December 31, 2013, BRH had financed $7,262 of its insurance premiums with Imperial Premium Financing Specialists; $4,720 was allocated to the Company. The note incurred interest at an annual rate of 3.97% with monthly payments of approximately $739 through October 31, 2014, at which time the note was repaid.

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Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

8. Debt (Continued)

Scheduled Maturities of Debt

Aggregate maturities of the Company's allocated indebtedness are as follows as of December 31, 2014:

2015	**$ 35,093**
2016	**31,693**
2017	**31,479**
2018	**31,091**
2019	**30,871**
Thereafter	**219,150**
Total	**379,377**
Less unamortized discounts	**9,047**
Total notes payable and long-term debt, net of discounts	**$ 370,330**

Interest and Related Financing Costs

Interest and related financing costs attributable to the Company's notes payable and long-term debt are comprised of the following for the periods described:

	Year Ended December 31, 2014	Period from August 16, 2013 to December 31, 2013
Interest expense	**$ 31,322**	$ 12,052
Other related financing costs	**4,923**	1,552
Total interest and related financing costs	**$ 36,245**	$ 13,604

Amounts presented above include parent allocations for interest expense of $29,608 and $10,531 and for other related financing costs of $4,819 and $1,535, for the year ended December 31, 2014 and the post-acquisition period from August 16, 2013 to December 31, 2013, respectively. There were no interest or related financing costs for the pre-acquisition period from January 1, 2013 to August 16, 2013.

9. Asset Retirement Obligations

The Company's asset retirement obligations as of December 31, 2013 were comprised of $8,720 for liabilities incurred from the Acquisition (Note 3). There was no significant change to the liability during the post-acquisition period from August 16, 2013 to December 31, 2013.

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

9. Asset Retirement Obligations (Continued)

Changes in the Company's ARO liabilities are summarized below for the year ended December 31, 2014:

Balance at beginning of year	**$ 8,720**
Accretion expense	**785**
Liabilities incurred	**584**
Change in estimate	**(914)**
Balance at end of year	**9,175**
Less current portion	**—**
Long-term portion	**$ 9,175**

Accretion expense was $462 for the pre-acquisition period from January 1, 2013 to August 16, 2013.

10. Employee Benefits

Group Health Insurance Plan

The Company's insurance program for employee group health insurance is funded by the Company up to certain retention levels. A reserve is recorded for those claims incurred but not paid prior to year-end based on prior experience and claims reported subsequent to year-end. Changes in estimates for claims incurred but not reported are recorded in the year the estimates are revised. The Company limits its risk by maintaining outside insurance for any individual claim exceeding $400. The Company has reserves of $1,607 and $706 as of December 31, 2014 and 2013, respectively, in accrued expenses. The Company recognized expenses for the employee group health plan of $9,073 for the year ended December 31, 2014 and $1,999 for the period from August 16, 2013 to December 31, 2013. Health insurance plan expenses for the pre-acquisition period from January 1, 2013 to August 16, 2013 are included in the allocations made by Arch (Note 11).

Workers' Compensation and Black Lung Insurance Plans

The Company is fully insured against claims by its active workforce for work-related injuries, including black lung claims, with the exception of claims by former employees with dates of loss prior to the Acquisition Date. In conjunction with the Acquisition (Note 3) the Company assumed a liability for black lung claims of former employees with dates of loss prior to the Acquisition Date, for which the Company is self-insured.

Losses arising from the Company's black lung benefits liability for active miners were accrued under the service cost method, based upon actuarial estimates of the aggregate liability for future claims. Losses arising from the Company's self-insured black lung benefits liability were accrued on an event driven approach, based upon actuarial estimates of the aggregate liability for claims incurred.

As of December 31, 2014 and 2013, the black lung benefits liability was $2,883 and $2,795, respectively, and was recorded in other noncurrent liabilities. The discount rate and healthcare inflation assumption used to estimate present value of future obligations for black lung was 4% in both 2014 and 2013. The health care inflation assumption was 5% in both 2014 and 2013.

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

10. Employee Benefits (Continued)

Workers' Compensation and Black Lung Insurance Plans (Continued)

Workers' compensation and black lung insurance plan expenses allocated to the Company for the pre-acquisition period from January 1, 2013 to August 16, 2013 are included in the allocations made by Arch (Note 11).

401(k) Plan

BRH sponsors a defined contribution retirement plan for substantially all employees, including employees of the Company since the Acquisition Date. The Company makes voluntary matching contributions to participants based upon a percentage of the participant's salary. The Company may also make additional contributions at its discretion. The Company's contributions totaled $4,370 for the year ended December 31, 2014 and $1,222 for the period from August 16, 2013 to December 31, 2013.

Pre-acquisition Arch Employee Plans

During the pre-acquisition period from January 1, 2013 to August 16, 2013, substantially all of the Company's employees were covered by Arch's non-contributory defined-benefit pension plan. The benefits were based on the employee's age and compensation. Arch funded the plans in an amount not less than the minimum statutory funding requirements or more than the maximum amount that can be deducted for federal income tax purposes.

The Company's eligible employees also received certain post-retirement medical and life insurance benefits under Arch's plans. Generally, covered employees who terminated employment after meeting eligibility requirements were eligible for post-retirement coverage for themselves and their dependents. The employee post-retirement medical/life plans were contributory, with retiree contributions adjusted periodically, and contained other cost-sharing features such as deductibles and coinsurance.

The Company's employees were also able to participate in Arch's savings plans that were established to assist eligible employees in providing for their future retirement needs.

The Company's allocated contributions related to Arch's employee benefit plans were approximately $5,800 for the pre-acquisition period from January 1, 2013 to August 16, 2013. Since the employees of the Company represent only a portion of Arch's (during Arch's period of ownership) benefit plan participants, the net obligation, plan assets, and funded status of these plans are the obligation of Arch (pre-acquisition) and, as such, are not reflected in these Financial Statements.

11. Related Party Transactions

Transactions between the Company and other affiliated companies not disclosed elsewhere are described below.

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Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

11. Related Party Transactions (Continued)

The Company has various coal sales agreements, for which revenue recognized from coal sales to related parties was comprised of the following for the periods indicated:

	Year Ended December 31, 2014	Period from August 16, 2013 to December 31, 2013
Bowie Coal Sales, LLC	**$ 100,684**	$ 15,654
Trafigura AG	**—**	5,055
Bowie Refined Coal, LLC	**2,176**	3,421
Total coal sales to related parties	**$ 102,860**	$ 24,130

There were no coal sales to related parties for the pre-acquisition period from January 1, 2013 to August 16, 2013.

Purchased coal from Bowie Coal Sales, LLC (BCS), a related party and wholly-owned subsidiary of BRH, totaled $15,136 for the year ended December 31, 2014. The Company did not purchase coal from related parties during 2013. BCS functions as the coal sales entity for BRH and often purchases coal from the Company and sells such coal to its end customer. With respect to export sales, coal purchased by BCS from the Company is transported to one of the California port terminals leased by BCS and loaded onto a vessel for delivery to the end customer. The sales price paid by BCS to the Company for these export sales is based on a calculation of the net profit (net back) to the mine from which the coal originated. Net back refers to the sales price to the end customer net of commissions, rail transportation costs, stevedoring, demurrage, other applicable port charges and any coal quality adjustments. BCS also sells the Company's coal domestically. For domestic sales, the sales price paid by BCS to the Company is equivalent to BCS' ultimate sales price to the end customer, net of transportation costs where the ultimate sales price is a delivered price. Collectively, the intent of coal sales to BCS is primarily administrative and pricing is intended such that BCS not recognize a profit on the sales but instead that profit will be returned to the coal mine that ultimately produced the coal.

Bowie Refined Coal, LLC (BRC) operates ten §45 Qualified Refined Coal Facilities in the United States. BRC's facilities refine coal waste into a reusable salable product with short prox analyses comparable to that of the native coal. From time to time, the Company sells its high ash waste coal to BRC to be washed at one of its refined coal facilities, where the sales price is determined based upon the Company's cost to deliver the coal to BRC. The Company may then repurchase the cleaned coal from BRC and sell it to its end customer, where the sales price for such cleaned coal is determined based upon BRC's original cost to purchase the coal plus costs incurred by BRC in the washing process and a yield loss adjustment. A member of Cedars Energy, LLC (the controlling partner of BRP referred to as Cedars) also owns a controlling interest in BRC. Since the member has a controlling interest in both the Company and BRC, BRC is deemed a related party. Amounts receivable from BRC totaled none and $414 as of December 31, 2014 and 2013, respectively, and pertain to high ash waste coal sold to BRC during the periods.

During August 2013, the Company entered into a coal services agreement with Trafigura AG (Trafigura), a multinational commodities trading corporation formed under the laws of the Country of

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Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

11. Related Party Transactions (Continued)

Switzerland, which is a wholly-owned subsidiary of Trafigura Beheer B.V. Trafigura Beheer B.V. also owns Galena Asset Management S.A., which manages Galena Private Equity Resource Fund, which owns Galena US Holdings, Inc., a Delaware corporation (Galena). Cedars and Galena formed BRP in June 2013 to facilitate a joint venture to acquire the Company. Galena holds a 46% minority ownership interest in BRP. Since Galena is owned by Trafigura Beheer B.V. and Galena has an ownership stake in the Company's ultimate parent, BRP, Trafigura is deemed a related party.

Trafigura also serves as the Company's exclusive marketing agent for which marketing fees paid by the Company to Trafigura totaled $1,354 for the year ended December 31, 2014. The Company did not pay marketing fees to related parties during 2013.

Additionally, the following amounts were allocated to the Company by BRH as of and for the periods indicated:

	Year Ended December 31, 2014	Period from August 16, 2013 to December 31, 2013
Balance Sheet		
Accounts receivable	**$ —**	$ 13
Prepaid expenses and other current assets	**936**	4,773
Property, plant and equipment, including mineral reserves and mine development costs, net	**281**	150
Deferred financing costs, net	**9,833**	12,341
Accounts payable	**493**	1,166
Accrued expenses	**3,095**	5,152
Current maturities of long-term debt and notes payable (net of unamortized original issue discount)	**23,728**	31,442
Long-term debt, less current portion (net of unamortized original issue discount)	**305,748**	344,092
Statements of Comprehensive (Loss) Income		
Other revenues, net of settlement expenses	**$ 29**	$ 64
Depreciation, depletion and amortization	**94**	14
Selling, general and administrative expenses	**17,543**	8,561
Interest expense and related financing costs	**34,427**	12,065

Amounts presented above were allocated in accordance with the methodology outlined in Note 2.

Related party transactions during the pre-acquisition period from January 1, 2013 to August 16, 2013 primarily relate to transactions between the Company and Arch. The Company was party to an accounts receivable securitization program with Arch whereby the Company sold its receivables to Arch without recourse at a discount based on the prime rate and day's sales outstanding. The discount on receivables sold to Arch totaled $380 for the pre-acquisition period from January 1, 2013 to August 16, 2013. Arch contributed certain reserves and other assets totaling $1,994 to the Company for inclusion in its sale in August 2013. Amounts allocated to the Company by Arch for selling, general and administrative services were approximately $8,000 and amounts allocated to the Company for Arch Western Bituminous Group's Grand Junction office were approximately $800.

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

12. Risk Concentrations

Revenues

The Company's two largest customers accounted for 29% and 24% of revenues for the year ended December 31, 2014, 21% and 19% of revenues for the period from August 16, 2013 to December 31, 2013, and 31% and 28% of revenues for the period from January 1, 2013 to August 16, 2013.

Cash

The Company routinely has cash on deposit with financial institutions which exceed Federal Deposit Insurance Corporation (FDIC) limits. Balances in excess of FDIC limits are subject to the risk that the financial institution will not pay upon demand. At December 31, 2014 and 2013, the Company's cash balances with financial institutions exceed the FDIC coverage by approximately $3,845 and $4,900, respectively.

Accounts Receivable

Two customers accounted for 49% and 21% of accounts receivable as of December 31, 2014 and 18% and 11% of accounts receivable as of December 31, 2013.

13. Commitments and Contingencies

Lease and Royalty Obligations

The Company leases equipment, buildings, coal reserves and various other properties under non-cancelable, long-term leases, expiring at various dates. The Company incurred rental expense for operating leases of $4,158, $1,461 and $1,178 for the year end December 31, 2014, the post-acquisition period from August 16, 2013 to December 31, 2013 and the pre-acquisition period from January 1, 2013 to August 16, 2013, respectively. Coal reserves lease agreements require royalties to be paid as the coal is mined. The Company incurred coal lease and royalty expenses of $28,326 for the year ended December 31, 2014, $11,545 for the period from August 16, 2013 to December 31, 2013, and $17,174 for the period from January 1, 2013 to August 16, 2013. Certain agreements require minimum annual royalties to be paid regardless of the amount of coal mined during the year. Certain agreements may also be cancelable at the Company's discretion.

A substantial amount of the coal mined by the Company is produced from mineral reserves leased from various land owners. One of the major lessors is the U.S. government, from which the Company leases substantially all of the coal it mines in Utah under terms set by Congress and administered by the U.S. Bureau of Land Management. These leases are generally for an initial term of ten years but may be extended by diligent development and mining of the reserves until all economically recoverable reserves are depleted. The Company has met the diligent development requirements for substantially all of these federal leases either directly through production, by including the lease as a part of a logical mining unit with other leases upon which development has occurred, or by paying an advance royalty in lieu of continued operations. Annual production on these federal leases must total at least 1% of the original amount of coal in the entire logical mining unit. In addition, royalties are payable monthly at a rate of 8% of the gross realization for coal produced using underground mining methods. The remainder of the leased coal is generally leased from state governments, land holding companies and various individuals. The duration of these leases varies greatly. Typically, the lease terms are

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Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

13. Commitments and Contingencies (Continued)

Lease and Royalty Obligations (Continued)

automatically extended as long as active mining continues. Royalty payments are generally based upon a specified rate per ton or a percentage of the gross realization from the sale of the coal.

Future noncancelable minimum royalty and lease payments under these agreements are as follows as of December 31, 2014:

	Coal Leases and Royalties	Other Leases
2015	$ 752	$ 843
2016	464	—
2017	464	—
2018	461	—
2019	336	—
Thereafter	1,676	—
Total	$ 4,153	$ 843

Environmental Matters

The Company believes it is in substantial compliance with federal, state and local environmental laws and regulations as currently promulgated. However, the exact nature of environmental control matters, if any, that the Company may encounter in the future cannot be predicted, primarily because of the increasing number, complexity and changing characteristics of environmental requirements that may be enacted by federal, state and local authorities. The Company's policy is to accrue for environmental expenses when the costs are probable and can be reasonably estimated.

Mine Safety and Health Administration

The Company is contesting several enforcement actions issued by the Federal Mine Safety and Health Administration. The matters are pending before an administrative law judge of the Federal Mine Safety and Health Review Commission. Discovery is ongoing. Management believes that the ultimate resolution of such matters will not have a material adverse effect on the financial position of the Company.

Off-Balance Sheet Arrangements

In the ordinary course of business, the Company is a party to certain off-balance sheet arrangements. These arrangements include financial instruments with off-balance sheet risk, such as performance on surety bonds. No liabilities related to these arrangements are reflected in the accompanying Balance Sheets, and management does not expect any material adverse effects on the Company's financial position, results of operations or cash flows as a result of these off-balance sheet arrangements.

The Company is required by authoritative agencies to provide collateral in the form of reclamation bonds to ensure the completion of future reclamation. As of December 31, 2014 and 2013, outstanding

Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

13. Commitments and Contingencies (Continued)

Off-Balance Sheet Arrangements (Continued)

surety bonds with third parties for post-mining reclamation totaled approximately $23,754 and $23,908, respectively. The Company had restricted cash totaling $3,100 and $4,600 as of December 31, 2014 and 2013, respectively, to secure bonding obligations.

Asset Purchase Agreement

On December 12, 2014, the Company (through its wholly-owned subsidiary, Fossil Rock Resources, LLC) entered into an agreement with an affiliate of PacifiCorp to acquire certain undeveloped, high Btu, low sulfur coal reserves in Utah (the Fossil Rock reserves), and BCS entered into a coal supply agreement with PacifiCorp to supply all of the coal requirements of PacifiCorp's Huntington Power Plant in Utah through 2029 (collectively, the Utah Transaction). The new coal supply agreement with PacifiCorp provides for sales to PacifiCorp of a minimum of 2.0 million tons and a maximum of 3.0 million tons of coal per year through 2029. As part of the Utah Transaction, BRH also entered into an agreement with PacifiCorp (through its wholly-owned subsidiary, Hunter Prep Plant, LLC) to acquire certain real property near the Hunter Power Plant, which will enhance coal blending capabilities for deliveries to the Hunter Power Plant. The Utah Transaction, subject to customary closing conditions, is expected to close in the first half of 2015 for a purchase price of $40,000, to be paid via the delivery by Fossil Rock Resources, LLC of $30,000 in cash at closing and the delivery by Hunter Prep Plant, LLC of a $10,000 promissory note to PacifiCorp, pending certain customary purchase price adjustments to be determined upon closing.

Legal Matters

The Company is subject to various lawsuits, claims and other legal proceedings arising in the ordinary course of business. The Company records costs relating to these matters when a loss is probable and the amount can be reasonably estimated; amounts are generally recorded in other accrued liabilities. Legal expenses incurred related to such lawsuits and claims are also accrued.

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Canyon Fuel Company, LLC

Notes to Audited Financial Statements (Continued)

Years Ended December 31, 2014 and 2013

14. Quarterly Selected Financial Data (Unaudited)

Unaudited quarterly selected financial data for the years ended December 31, 2014 and for the post-acquisition period from August 16, 2013 to December 31, 2013 and the pre-acquisition period from January 1, 2013 to August 16, 2013 is summarized below:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2014				
Coal sales	**$ 112,265**	**$ 97,514**	**$ 115,727**	**$ 94,298**
Operating income	**11,353**	**8,929**	**7,336**	**3,756**
Net income (loss)	**2,260**	**(246)**	**(1,871)**	**(5,014)**
Post-acquisition period from August 16, 2013 to December 31, 2013				
Coal sales	$ —	$ —	$ 52,279	$ 106,477
Operating (loss) income	—	—	(2,291)	6,057
Net loss	—	—	(5,979)	(3,859)
Pre-acquisition period from January 1, 2013 to August 16, 2013				
Coal sales	$ 91,122	$ 90,328	$ 37,690	$ —
Operating income	18,346	10,948	(10,986)	—
Net income (loss)	18,504	10,426	(11,002)	—

In the third quarter of 2013, the Company was acquired by BRH from Arch (Note 3).

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Canyon Fuel Company, LLC

Condensed Interim Balance Sheets

(in thousands)

	March 31, 2015 (Unaudited)	December 31, 2014
Assets		
Current assets:		
Accounts receivable	**$ 15,746**	$ 10,412
Inventories, net	**48,588**	52,375
Prepaid expenses and other current assets	**16,618**	6,992
Current portion of above market sales contracts	**12,423**	14,876
Total current assets	**93,375**	84,655
Property, plant and equipment, including mineral reserves and mine development costs, net	**344,557**	357,110
Restricted cash	**3,100**	3,100
Above market sales contracts, less current portion	**—**	867
Deferred financing costs, net	**9,457**	10,024
Other noncurrent assets	**3,646**	3,668
Total assets	**$ 454,135**	$ 459,424
Liabilities and member's equity		
Current liabilities:		
Accounts payable	**$ 28,037**	$ 27,655
Accrued expenses	**21,728**	21,149
Current portion of debt and short-term borrowings	**50,502**	33,151
Current portion of below market sales contracts	**5,538**	8,912
Total current liabilities	**105,805**	90,867
Debt, less current portion	**327,976**	337,179
Asset retirement obligation	**9,381**	9,175
Other noncurrent liabilities	**2,907**	2,883
Total liabilities	**446,069**	440,104
Commitments and contingencies (Note 11)		
Member's equity	**8,066**	19,320
Total liabilities and member's equity	**$ 454,135**	$ 459,424

The accompanying Notes are an integral part of these Condensed Interim Financial Statements.

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Canyon Fuel Company, LLC

Condensed Interim Statements of Operations and Comprehensive (Loss) Income

(in thousands)
(Unaudited)

	Three Months Ended March 31,	
	2015	**2014**
Revenues:		
Coal sales to non-related parties	**$ 45,697**	$ 92,485
Coal sales to related parties	**58,227**	19,780
Other revenues, net	**91**	89
Total revenues	**104,015**	112,354
Cost of coal sales, exclusive of items shown separately below	**74,587**	72,682
Purchased coal from related parties	**56**	3,387
Depreciation, depletion and amortization	**21,334**	18,592
Amortization of acquired sales contracts, net	**(54)**	3,181
Selling, general and administrative expenses	**4,173**	3,159
Operating income	**3,919**	11,353
Other expense:		
Interest expense and related financing costs	**(8,021)**	(9,093)
Net (loss) income and comprehensive (loss) income	**$ (4,102)**	$ 2,260

The accompanying Notes are an integral part of these Condensed Interim Financial Statements.

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Canyon Fuel Company, LLC

Condensed Interim Statements of Cash Flows

(in thousands)
(Unaudited)

	Three Months Ended March 31,	
	2015	**2014**
Operating activities		
Net (loss) income	**$ (4,102)**	$ 2,260
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depreciation, depletion and amortization	**21,334**	18,592
Amortization of acquired sales contracts, net	**(54)**	3,181
Amortization of discounts on notes payable	**490**	581
Accretion of asset retirement obligation	**206**	196
Amortization of deferred financing costs	**567**	653
Changes in operating assets and liabilities:		
Accounts receivable from non-related parties	**(5,334)**	(2,917)
Accounts receivable from related parties	**—**	414
Inventories	**3,787**	1,290
Prepaid expenses and other current assets	**(12,447)**	(4,525)
Other noncurrent assets	**22**	143
Accounts payable	**382**	(5,463)
Accrued expenses	**579**	(1,479)
Other noncurrent liabilities	**24**	15
Net cash provided by operating activities	**5,454**	12,941
Investing activities		
Purchases of property, plant and equipment	**(5,960)**	(1,119)
Net cash used in investing activities	**(5,960)**	(1,119)
Financing activities		
Proceeds from long-term debt and notes payable	**20,257**	5,025
Payments on long-term debt and notes payable	**(12,599)**	(12,684)
Net distributions to parent	**(7,152)**	(4,163)
Net cash provided by (used in) financing activities	**506**	(11,822)
Net change in cash	**—**	—
Cash at beginning of period	**—**	—
Cash at end of period	**$ —**	$ —
Supplemental disclosure of cash flow information		
Cash paid for interest	**$ 9,292**	$ 7,633
Supplemental disclosure of noncash activities		
Property, plant and equipment transferred from affiliate	**$ —**	$ 2,142

The accompanying Notes are an integral part of these Condensed Interim Financial Statements.

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Canyon Fuel Company, LLC

Notes to Condensed Interim Financial Statements

Three Months Ended March 31, 2015 and 2014

(Unaudited)

1. Description of Business

Canyon Fuel Company, LLC (the Company) operates three underground coal mines in Utah (two longwall operations and one room-and-pillar operation) and is wholly-owned by Bowie Resource Holdings, LLC (BRH), an entity that is wholly-owned by Bowie Resource Partners, LLC (BRP).

The Company engages in the extraction, cleaning and marketing of steam coal for sale primarily to major power plants in Utah, Nevada and California, as well as to cement, lime and gypsum plants and other industrial users in the western United States. In addition, the Company has access to port terminals in the State of California through which its coal is exported to a variety of growing international markets.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying Condensed Interim Financial Statements include the accounts of the Company, as a controlled entity of BRP, for the periods as of March 31, 2015 and December 31, 2014 and the results of operations and cash flows for the three months ended March 31, 2015 and 2014.

The Condensed Interim Financial Statements of the Company have been prepared on the accrual basis of accounting in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial statements and pursuant to the rules and regulations of the Securities and Exchange Commission. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. These Condensed Interim Financial Statements have also been prepared in accordance with Staff Accounting Bulletin Topic 1.B, *Allocation of Expenses and Related Disclosure in Financial Statements of Subsidiaries, Divisions or Lesser Business Components of Another Entity*. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included. Operating results for the three months ended March 31, 2015 are not necessarily indicative of the results that may be expected for the year ended December 31, 2015. These Condensed Interim Financial Statements should be read in conjunction with the audited financial statements of the Company for the year ended December 31, 2014.

The Condensed Interim Balance Sheet at December 31, 2014 has been derived from the audited financial statements at that date but does not include all of the information and footnotes required by GAAP for complete financial statements.

These Condensed Interim Financial Statements include allocations of assets, liabilities and expenses related to BRP's and BRH's corporate functions, including senior management, operations support, marketing, legal, human resources, finance and information technology. Allocations are based on proportional costs or incremental costs, whichever management has assessed is more representative of the amounts incurred by BRP or BRH, on behalf of the Company. These amounts are allocated on the basis of the number of locations or such other basis as deemed reasonably reflective of the Company's usage of the services provided by these related companies.

BRH allocates to the Company long term debt and related deferred financing costs and interest expense. BRH also allocates to the Company certain assets and liabilities attributable to or being

Canyon Fuel Company, LLC

Notes to Condensed Interim Financial Statements (Continued)

Three Months Ended March 31, 2015 and 2014

(Unaudited)

2. Summary of Significant Accounting Policies (Continued)

Basis of Presentation (Continued)

utilized by the Company. These accounts include accounts receivable; prepaid expenses and other current assets; capitalized computer hardware and software included in property, plant and equipment, including mineral reserves and mine development costs, net; other noncurrent assets; accounts payable and accrued expenses. Within the Condensed Interim Statements of Operations and Comprehensive (Loss) Income, allocations to the Company include amortization of capitalized computer hardware and software costs, reflected in depreciation, depletion and amortization; with all other cost allocations included in selling, general and administrative expenses.

The Company secures insurance coverage and bonding under programs maintained by BRH. As a result, the Company's costs under these programs may not reflect the costs it would otherwise incur if it operated as a stand-alone business.

Amounts, except per ton data, presented throughout these Condensed Interim Financial Statements are in thousands (000s) of U.S. Dollars, unless otherwise indicated.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect certain reported amounts and disclosures. Accordingly, actual results could differ from those estimates.

Company Environment and Risk Factors

The Company, in the course of its business activities, is exposed to a number of risks including fluctuating market conditions for coal, transportation and fuel costs, changing government regulations, unexpected maintenance and equipment failure, employee benefits cost control, changes in estimates of proven and probable coal reserves, the availability and timing of necessary mining permits and control of adequate recoverable mineral reserves. In addition, adverse weather and geological conditions may increase operating costs, sometimes substantially.

Centralized Treasury Function

The Company's treasury activities are centralized at BRH's corporate office in Louisville, Kentucky. The Company's excess cash is remitted to BRH and the Company's disbursement accounts are funded by BRH as amounts are presented for payment. Accordingly, the amounts due to or from BRH and its subsidiaries are primarily settled as a net distribution to parent, and are recorded in members' equity. Only minimal cash balances are maintained at the Company level.

Segment Information

The Company operates as a single reportable segment, as the Company's Chief Executive Officer, serving as the Chief Operating Decision Maker (CODM), reviews financial information on the basis of the Company's consolidated financial results for purposes of making decisions. Generally, the CODM evaluates performance and allocates resources based on Adjusted EBITDA. EBITDA is defined as net

Canyon Fuel Company, LLC

Notes to Condensed Interim Financial Statements (Continued)

Three Months Ended March 31, 2015 and 2014

(Unaudited)

2. Summary of Significant Accounting Policies (Continued)

Segment Information (Continued)

income (loss) before interest expense, income tax, depreciation, depletion and amortization. Adjusted EBITDA is defined as EBITDA further adjusted for accretion of asset retirement obligations, gain or loss on sale of assets, casualty losses and other taxes. Discrete financial information sufficient to allow the CODM to make decisions is only available on a consolidated basis.

Income Taxes

The Company is a single member limited liability company that is treated as a disregarded entity for federal and state income tax purposes. The Company's parent has elected to be treated as a partnership for federal and state income tax purposes. A partnership is not a tax paying entity for federal and state income tax purposes. Income, loss, deductions and credits of the Company pass through to its member and are taxed at the member's income tax rate. Accordingly, no provision for income taxes is provided in these Condensed Interim Financial Statements. The Company reports any tax-related interest and penalties as a component of other expense. The Company makes distributions to its member to cover the member's estimated state and federal income taxes payable as a result of the operations of the Company.

The Company does not believe there are any material uncertain tax positions and, accordingly, it did not recognize a liability for unrecognized benefits in the Condensed Interim Balance Sheets at March 31, 2015 or December 31, 2014. The Company does not anticipate any significant change in unrecognized tax benefits during the next twelve months.

The Company remains open to state examinations for tax years ended December 31, 2013 to December 31, 2014. The Company is not currently under examination by the Internal Revenue Service, state or local tax authorities.

Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Valuation techniques used must maximize the use of observable inputs and minimize the use of unobservable inputs.

A three level hierarchy has been established for valuing assets and liabilities based on how transparent (observable) the inputs are that are used to determine fair value, with the inputs considered most observable categorized as Level 1 and those that are least observable categorized as Level 3. Hierarchy levels are defined below:

Level 1: Quoted prices in active markets for identical assets and liabilities;

Level 2: Quoted prices for similar assets and liabilities in active markets; quoted prices for identical or similar instruments in markets that are not active; and

Level 3: Unobservable inputs that are supported by little or no market data which require the reporting entity to develop its own assumptions.

Canyon Fuel Company, LLC

Notes to Condensed Interim Financial Statements (Continued)

Three Months Ended March 31, 2015 and 2014

(Unaudited)

2. Summary of Significant Accounting Policies (Continued)

Fair Value Measurements (Continued)

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of assets and liabilities and their placement within the fair value hierarchy levels.

The Company's accounts receivable, restricted cash, accounts payable and accrued expenses are considered financial instruments. These assets and liabilities are reflected at fair value or at carrying amounts that approximate their fair value due to the short-term nature or the terms of the instruments. The estimated carrying value of the Company's debt approximates its fair value because the effective interest rates are not significantly different from current market rates. The Company does not have any nonfinancial assets or nonfinancial liabilities measured at fair value on a recurring basis, other than ARO. The inputs and techniques used to derive ARO fair value are described in the Asset Retirement Obligations section of Note 2 to the audited financial statements. This fair value determination is classified as Level 3 in the hierarchy.

The Company measures the fair value of certain assets on a non-recurring basis, generally when events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. The Company's policy is further described in the Property, Plant and Equipment section of Note 2 to the audited financial statements.

Recently Issued Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (FASB) issued *Accounting Standards Update (ASU) No. 2014-09: Revenue from Contracts with Customers*. The standard outlines a five-step model for revenue recognition with the core principle being that a company should recognize revenue when it transfers control of goods or services to customers at an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. Companies can either apply a full retrospective approach or a modified retrospective approach. For public business entities, the amendment is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. For nonpublic entities, the amendment is effective for annual reporting periods beginning after December 15, 2017, and interim reporting periods within annual reporting periods beginning after December 15, 2018. Early adoption is permitted for nonpublic entities. The Company has not yet made a determination as to whether it will early adopt the provisions of this new standard nor has any determination been made as to the method of application. It is too early to assess whether the impact of the adoption of this new guidance will have a material impact on the Company's results of operations, financial position or cash flows.

In April 2015, the FASB issued ASU No. 2015-03 Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. For public business entities, the amendments are effective for financial statements issued for fiscal years beginning after December 31, 2015, and interim periods within those fiscal years. For nonpublic entities, the

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Canyon Fuel Company, LLC

Notes to Condensed Interim Financial Statements (Continued)

Three Months Ended March 31, 2015 and 2014

(Unaudited)

2. Summary of Significant Accounting Policies (Continued)

Recently Issued Accounting Pronouncements (Continued)

amendments are effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within fiscal years beginning after December 15, 2016. We do not expect the adoption of this amendment to have a material impact on the Company's results of operations, financial position or cash flows, as there are no changes to the recognition and measurement guidance for debt issuance costs.

The Company does not expect the adoption of any other recently issued accounting pronouncements to have a material impact on its Financial Statements.

Subsequent Events

In preparation of the accompanying Condensed Interim Financial Statements, management has evaluated events that have occurred subsequent to the balance sheet date through May 5, 2015, the date the Condensed Interim Financial Statements were issued.

3. Inventories

Inventories consist of the following as of:

	March 31, 2015	December 31, 2014
Coal	**$ 36,225**	$ 40,415
Parts and supplies, net of allowance	**12,363**	11,960
Total inventories, net	**$ 48,588**	$ 52,375

Parts and supplies inventories are stated net of an allowance for slow-moving and obsolete inventories of $796 and $853 at March 31, 2015 and December 31, 2014, respectively.

4. Prepaid Expenses and Other Current Assets

Prepaid expenses and other current assets consist of the following as of:

	March 31, 2015	December 31, 2014
Prepaid insurance	**$ 9,936**	$ 2,562
Longwall costs, net	**6,399**	4,083
Other	**283**	347
Total prepaid expenses and other current assets	**$ 16,618**	$ 6,992

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Canyon Fuel Company, LLC

Notes to Condensed Interim Financial Statements (Continued)

Three Months Ended March 31, 2015 and 2014

(Unaudited)

5. Property, Plant and Equipment

Property, plant and equipment, including mineral reserves and mine development costs, consist of the following as of:

	March 31, 2015	December 31, 2014
Mining and other equipment	**$ 323,340**	$ 318,480
Mineral reserves	**47,372**	47,372
Mine development costs	**55,042**	55,042
Land and buildings	**28,964**	28,964
Capitalized asset retirement costs	**485**	485
Construction in progress	**9,717**	8,617
	464,920	458,960
Less accumulated depreciation, depletion and amortization	**120,363**	101,850
Net property, plant and equipment	**$ 344,557**	$ 357,110

Depreciation expense for the Company was $15,992 and $15,728 for the three months ended March 31, 2015 and 2014, respectively. Depletion and amortization expense on mineral reserves, mine development costs and capitalized asset retirement costs was $2,521 and $2,864 for the three months ended March 31, 2015 and 2014, respectively. Depreciation, depletion and amortization commences upon in service date.

6. Accrued Expenses

Accrued expenses consist of the following as of:

	March 31, 2015	December 31, 2014
Accrued payroll, vacation and related expenses	**$ 4,638**	$ 7,376
Accrued property and production taxes	**5,019**	3,485
Accrued interest on debt and other borrowings	**443**	1,111
Other general liabilities	**5,922**	6,829
Freight payable	**2,770**	741
Health insurance plan reserve	**2,936**	1,607
Total accrued expenses	**$ 21,728**	$ 21,149

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Canyon Fuel Company, LLC

Notes to Condensed Interim Financial Statements (Continued)

Three Months Ended March 31, 2015 and 2014

(Unaudited)

7. Debt

The Company's total indebtedness consisted of the following as of:

	March 31, 2015	December 31, 2014
2013 Senior Secured Credit Facility, net	**$ 334,705**	$ 329,476
Notes payable to Sevier Special Service District #1	**25,816**	28,387
Notes payable to Prudential Insurance Company of America	**10,767**	12,467
Notes payable to Imperial Premium Financing Specialists	**7,190**	—
Total indebtedness	**378,478**	370,330
Less current portion	**50,502**	33,151
Long-term debt	**$ 327,976**	$ 337,179

The carrying amount of the 2013 Senior Secured Credit Facility is presented above net of the respective unamortized original issue discount (including amounts allocated from BRH) of $8,557 and $9,047 at March 31, 2015 and December 31, 2014, respectively.

2013 Senior Secured Credit Facility

BRH had $298,639 and $304,483 outstanding under the 2013 First Lien Term Loan as of March 31, 2015 and December 31, 2014, respectively (net of an unamortized original issue discount of $7,049 and $7,486, as of March 31, 2015 and December 31, 2014, respectively). Additionally, BRH had $75,069 and $74,935 outstanding under the 2013 Second Lien Term Loan as of March 31, 2015 and December 31, 2014, respectively (net of an unamortized original issue discount of $2,931 and $3,065, as of March 31, 2015 and December 31, 2014, respectively). Amounts allocated to the Company by BRH for the 2013 First Lien Term Loan were $256,083 and $261,094 as of March 31, 2015 and December 31, 2014, respectively (net of allocated, unamortized original issue discounts of $6,044 and $6,419, as of March 31, 2015 and December 31, 2014, respectively). BRH allocated $64,372 and $64,257 to the Company for the 2013 Second Lien Term Loan as of March 31, 2015 and December 31, 2014, respectively (net of allocated, unamortized original issue discounts of $2,513 and $2,628, as of March 31, 2015 and December 31, 2014, respectively). Interest rates payable at March 31, 2015 and December 31, 2014 were LIBOR (with a floor of 1.00%) plus: (1) in the case of the 2013 First Lien Term Loan 5.75%, or 6.75% in total; and (2) in the case of the 2013 Second Lien Term Loan 10.75%, or 11.75% in total. The 2013 First Lien Term Loan is also subject to quarterly amortization of escalating rates ranging from 1.25% to 2.50% which commenced on August 16, 2013.

As of March 31, 2015 and December 31, 2014, respectively, BRH had $19,000 and $5,500 in borrowings outstanding under the 2013 ABL and the remaining availability was $16,000 and $29,500, respectively. Amounts allocated to the Company for the 2013 ABL were $14,250 and $4,125 as of March 31, 2015 and December 31, 2014, respectively. The interest rates payable on the ABL at March 31, 2015 were LIBOR plus 2.00%, or 2.17% for the first $12,500 and the base rate of 3.25% plus 1.00%, or 4.25%, on the remaining $6,500. The interest rates payable at December 31, 2014 were LIBOR plus 2.00%, or 2.16% for the first $5,000 and the base rate of 3.25% plus 1.00%, or 4.25%, on the balances in excess of $5,000.

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Canyon Fuel Company, LLC

Notes to Condensed Interim Financial Statements (Continued)

Three Months Ended March 31, 2015 and 2014

(Unaudited)

7. Debt (Continued)

2013 Senior Secured Credit Facility (Continued)

Under the 2013 Senior Secured Credit Facility, BRH must comply with one financial covenant on a quarterly basis, which is the maximum senior secured leverage ratio for which the maximum ratio could not exceed 3.5 to 1 as of March 31, 2015 or December 31, 2014. BRH was in compliance with this covenant at March 31, 2015 and December 31, 2014. The 2013 ABL requires compliance with an additional financial covenant, the fixed charge coverage ratio, upon the occurrence and during the continuation of a covenant trigger period, as defined in the 2013 ABL. BRH was not in a covenant trigger period at any point during the three months ended March 31, 2015 or the year ended December 31, 2014. In addition, the 2013 ABL requires submission of a monthly borrowing base calculation and certificate to determine net availability under the 2013 ABL.

In 2015, BRH intends to refinance its obligations under the 2013 Senior Secured Credit Facility. If such refinancing does not occur by the end of the third quarter of 2015, BRH does not expect to be in compliance with the maximum senior secured leverage ratio, in which case BRH intends to exercise its ability to Cure, as defined in the 2013 Senior Secured Credit Facility. BRH may not be successful in its refinancing efforts or may not be able to Cure the maximum senior secured leverage ratio breach, which would result in an event of default as defined in the 2013 Senior Secured Credit Facility. These Condensed Interim Financial Statements are prepared assuming the Company will continue as a going concern and do not include any adjustments that might result from the outcome of this uncertainty.

Notes Payable to Imperial Premium Financing Specialists

In February 2015, BRH financed annual insurance premiums for its insurance policies in the amount of $13,332 with Imperial Premium Financing Specialists (IPFS). The note bears interest at 3.97% with monthly payments of $1,202. Amounts owed by BRH to IPFS for financed insurance premiums totaled $9,477 as of March 31, 2015 of which $7,190 was allocated to the Company. No amounts were outstanding with IPFS as of December 31, 2014.

Interest and Related Financing Costs

Interest and related financing costs attributable to the Company's notes payable and long-term debt are comprised of the following for the three months ended March 31:

	2015	2014
Interest expense	**$ 6,965**	$ 7,858
Other related financing costs	**1,056**	1,235
Total interest and related financing costs	**$ 8,021**	$ 9,093

Amounts presented above include parent allocations for interest expense of $6,606 and $7,376 and for other related financing costs of $1,031 and $1,209, for the three months ended March 31, 2015 and 2014, respectively.

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Canyon Fuel Company, LLC

Notes to Condensed Interim Financial Statements (Continued)

Three Months Ended March 31, 2015 and 2014

(Unaudited)

8. Asset Retirement Obligations

Changes in the Company's ARO liabilities are summarized below as of:

	March 31, 2015	December 31, 2014
Balance at beginning of year	**$ 9,175**	$ 8,720
Accretion expense	**206**	785
Liabilities incurred	**—**	584
Change in estimate	**—**	(914)
Balance at end of year	**9,381**	9,175
Less current portion	**—**	—
Long-term portion	**$ 9,381**	$ 9,175

9. Related Party Transactions

Transactions between the Company and other affiliated companies not disclosed elsewhere are described below.

The Company has various coal sales agreements, for which revenue recognized from coal sales to related parties was comprised of the following for the three months ended March 31:

	2015	2014
Bowie Coal Sales, LLC	**$ 58,227**	$ 16,974
Bowie Refined Coal, LLC	**—**	2,806
Total coal sales to related parties	**$ 58,227**	$ 19,780

Purchased coal from Bowie Coal Sales, LLC (BCS), a related party and wholly-owned subsidiary of BRH, totaled $56 and $3,387 for the three months ended March 31, 2015 and 2014, respectively. BCS functions as the coal sales entity for BRH and often purchases coal from the Company and sells such coal to its end customer. With respect to export sales, coal purchased by BCS from the Company is transported to one of the California port terminals leased by BCS and loaded onto a vessel for delivery to the end customer. The sales price paid by BCS to the Company for these export sales is based on a calculation of the net profit (net back) to the mine from which the coal originated. Net back refers to the sales price to the end customer net of commissions, rail transportation costs, stevedoring, demurrage, other applicable port charges and any coal quality adjustments. BCS also sells the Company's coal domestically. For domestic sales, the sales price paid by BCS to the Company is equivalent to BCS' ultimate sales price to the end customer, net of transportation costs where the ultimate sales price is a delivered price. Collectively, the intent of coal sales to BCS is primarily administrative and pricing is intended such that BCS not recognize a profit on the sales but instead that profit will be returned to the coal mine that ultimately produced the coal.

Bowie Refined Coal, LLC (BRC) operates ten §45 Qualified Refined Coal Facilities in the United States. BRC's facilities refine coal waste into a reusable salable product with short prox analyses comparable to that of the native coal. From time to time, the Company sells its high ash waste coal to

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Canyon Fuel Company, LLC

Notes to Condensed Interim Financial Statements (Continued)

Three Months Ended March 31, 2015 and 2014

(Unaudited)

9. Related Party Transactions (Continued)

BRC to be washed at one of its refined coal facilities, where the sales price is determined based upon the Company's cost to deliver the coal to BRC. The Company, through its affiliate, BCS, may then repurchase the cleaned coal from BRC and sell it to its end customer, where the sales price for such cleaned coal is determined based upon BRC's original cost to purchase the coal plus costs incurred by BRC in the washing process and a yield loss adjustment. A member of Cedars Energy, LLC (the controlling partner of BRP referred to as Cedars) also owns a controlling interest in BRC. Since the member has a controlling interest in both the Company and BRC, BRC is deemed a related party.

During August 2013, the Company entered into a coal services agreement with Trafigura AG (Trafigura), a multinational commodities trading corporation formed under the laws of the Country of Switzerland, which is a wholly-owned subsidiary of Trafigura Beheer B.V. Trafigura Beheer B.V. also owns Galena Asset Management S.A., which manages Galena Private Equity Resource Fund, which owns Galena US Holdings, Inc., a Delaware corporation (Galena). Cedars and Galena formed BRP in June 2013 to facilitate a joint venture to acquire the Company. Galena holds a 46% minority ownership interest in BRP. Since Galena is owned by Trafigura Beheer B.V. and Galena has an ownership stake in the Company's ultimate parent, BRP, Trafigura is deemed a related party.

Trafigura also serves as the Company's exclusive marketing agent for which marketing fees paid by the Company to Trafigura totaled $990 and $213 for the three months ended March 31, 2015 and 2014, respectively.

Additionally, the following amounts were allocated to the Company by BRH as of and for the periods indicated:

	March 31, 2015	December 31, 2014
Balance Sheet		
Prepaid expenses and other current assets	**$ 8,454**	$ 936
Property, plant and equipment, including mineral reserves and mine development costs, net	**252**	281
Deferred financing costs, net	**9,292**	9,833
Accounts payable	**655**	493
Accrued expenses	**1,575**	3,095
Current maturities of long-term debt and notes payable (net of unamortized original issue discount)	**41,068**	23,728
Long-term debt, less current portion (net of unamortized original issue discount)	**300,827**	305,748

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Canyon Fuel Company, LLC

Notes to Condensed Interim Financial Statements (Continued)

Three Months Ended March 31, 2015 and 2014

(Unaudited)

9. Related Party Transactions (Continued)

	Three Months Ended March 31,	
	2015	**2014**
Statements of Comprehensive (Loss) Income		
Other revenues, net of settlement expenses	**$ —**	$ 39
Depreciation, depletion and amortization	**29**	14
Selling, general and administrative expenses	**4,166**	3,158
Interest expense and related financing costs	**7,637**	8,584

Amounts presented above were allocated in accordance with the methodology outlined in Note 2.

10. Risk Concentrations

Revenues

Two customers accounted for 56% and 36% of revenues for the three months ended March 31, 2015 and three customers accounted for 27%, 25% and 15% of revenues for three months ended March 31, 2014.

Cash

The Company routinely has cash on deposit with financial institutions which exceed Federal Deposit Insurance Corporation (FDIC) limits. Balances in excess of FDIC limits are subject to the risk that the financial institution will not pay upon demand. At March 31, 2015, the Company's cash balances with financial institutions exceeded the FDIC coverage by approximately $3,084.

Accounts Receivable

One customer accounted for 83% of accounts receivable as of March 31, 2015 and two customers accounted for 49% and 21% of accounts receivable as of December 31, 2014.

11. Commitments and Contingencies

Lease and Royalty Obligations

The Company leases equipment, buildings, coal reserves and various other properties under non-cancelable, long-term leases, expiring at various dates. The Company incurred rental expense for operating leases of $443 and $1,396 for the three months ended March 31, 2015 and 2014, respectively. Coal reserves lease agreements require royalties to be paid as the coal is mined. The Company incurred coal lease and royalty expenses of $7,463 and $8,319 for three months ended March 31, 2015 and 2014, respectively. Certain agreements require minimum annual royalties to be paid regardless of the amount of coal mined during the year. Certain agreements may also be cancelable at the Company's discretion.

A substantial amount of the coal mined by the Company is produced from mineral reserves leased from various land owners. One of the major lessors is the U.S. government, from which the Company

Canyon Fuel Company, LLC

Notes to Condensed Interim Financial Statements (Continued)

Three Months Ended March 31, 2015 and 2014

(Unaudited)

11. Commitments and Contingencies (Continued)

Lease and Royalty Obligations (Continued)

leases substantially all of the coal it mines in Utah under terms set by Congress and administered by the U.S. Bureau of Land Management. These leases are generally for an initial term of ten years but may be extended by diligent development and mining of the reserves until all economically recoverable reserves are depleted. The Company has met the diligent development requirements for substantially all of these federal leases either directly through production, by including the lease as a part of a logical mining unit with other leases upon which development has occurred, or by paying an advance royalty in lieu of continued operations. Annual production on these federal leases must total at least 1% of the original amount of coal in the entire logical mining unit. In addition, royalties are payable monthly at a rate of 8% of the gross realization for coal produced using underground mining methods. The remainder of the leased coal is generally leased from state governments, land holding companies and various individuals. The duration of these leases varies greatly. Typically, the lease terms are automatically extended as long as active mining continues. Royalty payments are generally based upon a specified rate per ton or a percentage of the gross realization from the sale of the coal.

Environmental Matters

The Company believes it is in substantial compliance with federal, state and local environmental laws and regulations as currently promulgated. However, the exact nature of environmental control matters, if any, that the Company may encounter in the future cannot be predicted, primarily because of the increasing number, complexity and changing characteristics of environmental requirements that may be enacted by federal, state and local authorities. The Company's policy is to accrue for environmental expenses when the costs are probable and can be reasonably estimated.

Mine Safety and Health Administration

The Company is contesting several enforcement actions issued by the Federal Mine Safety and Health Administration. The matters are pending before an administrative law judge of the Federal Mine Safety and Health Review Commission. Discovery is ongoing. Management believes that the ultimate resolution of such matters will not have a material adverse effect on the financial position of the Company.

Off-Balance Sheet Arrangements

In the ordinary course of business, the Company is a party to certain off-balance sheet arrangements. These arrangements include financial instruments with off-balance sheet risk, such as performance on surety bonds. No liabilities related to these arrangements are reflected in the accompanying Balance Sheets, and management does not expect any material adverse effects on the Company's financial position, results of operations or cash flows as a result of these off-balance sheet arrangements.

The Company is required by authoritative agencies to provide collateral in the form of reclamation bonds to ensure the completion of future reclamation. As of March 31, 2015 and December 31, 2014, outstanding surety bonds with third parties for post-mining reclamation totaled approximately $24,416

Canyon Fuel Company, LLC

Notes to Condensed Interim Financial Statements (Continued)

Three Months Ended March 31, 2015 and 2014

(Unaudited)

11. Commitments and Contingencies (Continued)

Off-Balance Sheet Arrangements (Continued)

and $23,754, respectively. The Company had restricted cash totaling $3,100 as of March 31, 2015 and December 31, 2014, respectively, to secure bonding obligations.

Asset Purchase Agreement

On December 12, 2014, the Company (through its wholly-owned subsidiary, Fossil Rock Resources, LLC) entered into an agreement with an affiliate of PacifiCorp to acquire certain undeveloped, high Btu, low sulfur coal reserves in Utah (the Fossil Rock reserves), and BCS entered into a coal supply agreement with PacifiCorp to supply all of the coal requirements of PacifiCorp's Huntington Power Plant in Utah through 2029 (collectively, the Utah Transaction). The new coal supply agreement with PacifiCorp provides for sales to PacifiCorp of a minimum of 2.0 million tons and a maximum of 3.0 million tons of coal per year through 2029. As part of the Utah Transaction, BRH also entered into an agreement with PacifiCorp (through its wholly-owned subsidiary, Hunter Prep Plant, LLC) to acquire certain real property near the Hunter Power Plant, which will enhance coal blending capabilities for deliveries to the Hunter Power Plant. The Utah Transaction, subject to customary closing conditions, is expected to close in the first half of 2015 for a purchase price of $40,000, to be paid via the delivery by Fossil Rock Resources, LLC of $30,000 in cash at closing and the delivery by Hunter Prep Plant, LLC of a $10,000 promissory note to PacifiCorp, pending certain customary purchase price adjustments to be determined upon closing.

Legal Matters

The Company is subject to various lawsuits, claims and other legal proceedings arising in the ordinary course of business. The Company records costs relating to these matters when a loss is probable and the amount can be reasonably estimated; amounts are generally recorded in other accrued liabilities. Legal expenses incurred related to such lawsuits and claims are also accrued.

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APPENDIX A
FORM OF FIRST AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP

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APPENDIX B
GLOSSARY OF DEFINED TERMS

ARO: Asset retirement obligations.

ash: Inorganic material consisting of iron, alumina, sodium and other incombustible matter that are contained in coal. The composition of the ash can affect the burning characteristics of coal.

Atlantic market: A term used to describe a geographic region of the world where goods are traded and shipped primarily on the Atlantic Ocean.

bituminous coal: A soft black coal with a heat content that ranges from 10,500 to 14,000 Btu per pound, as received. This coal is located primarily in Appalachia, Arizona, the Midwest, Colorado and Utah, and is the type most commonly used for electricity generation in the United States. Bituminous coal is also used for industrial steam purposes and as metallurgical coal used in steel production.

BLM: U.S. Bureau of Land Management.

Btu: British thermal units, or Btu, is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.

CAIR: Clean Air Interstate Rule.

Central Appalachia: Coal producing area in eastern Kentucky, Virginia and southern West Virginia and northern Tennessee.

CERCLA: The Comprehensive Environmental Response, Compensation, and Liability Act of 1980.

Clean Air Act: The federal law enacted to regulate air emissions, as amended to date.

coal seam: Coal deposits occur in layers typically separated by layers of rock. Each layer is called a "seam." A seam can vary in thickness from inches to a hundred feet or more.

Code: The Internal Revenue Code of 1986, as amended.

coke: A hard, dry carbon substance produced by heating coal to a very high temperature in the absence of air. Coke is used in the manufacture of iron and steel. Its production results in a number of useful by-products.

compliance coal: Any coal that emits less than 1.2 pounds of sulfur dioxide per million Btu when burned without blending other coals or using sulfur dioxide reduction technologies in order to comply with the requirements of the Clean Air Act.

continuous mining: A form of underground room and pillar mining, which involves the excavation of a series of "rooms" into the coal seam leaving "pillars" or columns of coal to help support the mine roof. A specialized cutting machine, the continuous miner, mechanizes the extraction procedure. Continuous miners tear the coal from the seam and load it onto conveyors or into shuttle cars in a continuous operation. This is to be distinguished from a conventional mining unit which must stop the extraction process in order for loading to commence.

Cost of coal sales, exclusive of items shown separately: When referenced in this prospectus, means cost of coal sales, exclusive of transportation, depreciation, depletion and amortization, and accretion on asset retirement obligations; when referenced in the financial statements, means cost of coal sales, exclusive of depreciation, depletion and amortization.

CSAPR: Cross-State Air Pollution Rule.

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CWA: The Clean Water Act of 1972.

EIA: U.S. Energy Information Administration.

EPA: Environmental Protection Agency.

ERISA: The Employee Retirement Income Security Act of 1974, as amended.

FOB: Free on board. The term generally specifies the location at which title, and hence risk of loss, transfers from a seller to a buyer.

Four Corners: A region of the United States consisting of the southwestern corner of Colorado, northwestern corner of New Mexico, northeastern corner of Arizona and southeastern corner of Utah.

fossil fuel: A hydrocarbon such as coal, petroleum or natural gas that may be used as a fuel.

GAAP: Generally accepted accounting principles in the United States.

general partner: Bowie GP, LLC, our general partner.

GHG: Greenhouse gas(es).

high sulfur coal: Coal with a sulfur content of greater than 1.5%.

Illinois Basin: Coal producing area in Illinois, Indiana and western Kentucky.

IEA: International Energy Agency.

IPA: Intermountain Power Agency.

IRAs: Individual Retirement Accounts.

IRS: Internal Revenue Service.

LBA: Lease by application.

lignite: The lowest rank of coal. It is brownish-black with a high moisture content commonly above 35% by weight and heating value commonly less than 8,000 Btu.

longwall mining: A productive underground mining method in the United States. A shearer with two rotating cutting drums trams across the longwall face, cutting the coal and transferring it to an armored chain conveyor. Hydraulic supports hold the roof as the longwall system advances through the coal.

low sulfur coal: Coal with a sulfur content of less than 1.0%.

LTIP: Long-term incentive plan.

MATS: Mercury and Air Toxics Standards.

medium sulfur coal: Coal with a sulfur content greater than or equal to 1.0% but less than or equal to 1.5%.

metallurgical coal: The various grades of coal suitable for carbonization to make coke for steel manufacture. Its quality depends on four important criteria: volatility, which affects coke yield; the level of impurities including sulfur and ash, which affects coke quality; composition, which affects coke strength; and basic characteristics, which affect coke oven safety. Metallurgical coal typically has a particularly high Btu but low ash and sulfur content.

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MINER Act: Mine Improvement and New Emergency Response Act of 2006.

MSHA: Mine Safety and Health Administration.

Mt: Millions of tons.

NAAQS: National Ambient Air Quality Standards.

natural gas: Hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane and other gasses.

NEPA: National Environmental Policy Act.

nitrogen oxide: A gas formed in high temperature environments such as coal combustion. It is reported to contribute to ground level ozone and visibility degradation.

non-reserve coal deposits: Non-reserve coal deposits are coal-bearing bodies that have been sufficiently sampled and analyzed in trenches, outcrops, drilling and underground workings to assume continuity between sample points, and therefore warrant further exploration stage work. However, this coal does not qualify as a commercially viable coal reserve as prescribed by standards of the SEC until a final comprehensive evaluation based on unit cost per ton, recoverability and other material factors concludes legal and economic feasibility. Non-reserve coal deposits may be classified as such by either limited property control or geological limitations, or both.

Northern Appalachia: Coal producing area in Ohio, Pennsylvania, Maryland and northern West Virginia.

NPDES: The National Pollutant Discharge Elimination System.

NYSE: New York Stock Exchange.

OSM: The Office of Surface Mining Reclamation and Enforcement.

overburden: Layers of earth and rock covering a coal seam. In surface mining operations, overburden is removed prior to coal extraction.

Pacific market: A term used to described a geographic region of the world where goods are traded and shipped primarily on the Pacific and Indian Oceans.

Pacific Rim: Geographic area surrounding the edges of the Pacific Ocean, including the western shores of North America and South America, Australia, eastern Asia and the islands of the Pacific.

Powder River Basin: Coal producing area in Wyoming and Montana.

preparation plant: Usually located on a mine site, although one plant may serve several mines. A preparation plant is a facility for crushing, sizing and washing coal to prepare it for use by a particular customer. The washing process separates higher ash coal and may also remove some of the coal's sulfur content.

probable (indicated) reserves: Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling, and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

proven (measured) reserves: Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of

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detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

PSD: Prevention of Significant Deterioration.

QSOs: Qualified Surface Owners.

RCRA: Resource Conservation and Recovery Act.

reclamation: The process of restoring land to its prior condition, productive use or other permitted condition following mining activities. The process commonly includes "recontouring" or reshaping the land to its approximate original appearance, restoring topsoil and planting native grass and shrubs. Reclamation operations are typically conducted concurrently with mining operations. Reclamation is closely regulated by both state and federal laws.

reserve: That part of a mineral deposit that could be economically and legally recovered or produced at the time of the reserve determination.

room and pillar mining: A system of coal mining commonly used in the U.S. in which rooms are driven off the entries with pillars of coal left standing between them for temporary or permanent roof support.

Rule 144: Rule 144 under the Securities Act.

Savage: Savage Services Corporation.

Securities Act: The Securities Act of 1933.

SEC: United States Securities and Exchange Commission.

Severance tax: A tax imposed on the removal of a natural resource, such as crude oil or coal.

SMCRA: The Surface Mining Control and Reclamation Act of 1977, as amended.

subsidence: Lateral or vertical movement of surface land that occurs when the roof of an underground mine collapses. Longwall mining causes planned subsidence by the mining out of coal that supports the overlying strata.

sulfur: One of the elements present in varying quantities in coal that contributes to environmental degradation when coal is burned. Sulfur dioxide is produced as a gaseous by-product of coal combustion.

surface mine: A mine in which the coal lies near the surface and can be extracted by removing the covering layer of soil overburden. Surface mines are also known as open-pit mines.

thermal coal: Coal used by power plants and industrial steam boilers to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal. It is also commonly referred to as "steam coal."

throughput: The volume of product passing through a facility.

TMDL: Total Maximum Daily Load.

tons: A "short" or net ton is equal to 2,000 pounds. A "long" or British ton is 2,240 pounds. A "metric" ton is approximately 2,205 pounds. The short ton is the unit of measure referred to in this

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prospectus, unless otherwise stated. A "clean" ton is a produced ton that has undergone requisite cleaning and preparation processes.

Treasury Regulations: The existing and proposed regulations promulgated by the U.S. Treasury Department under the Code.

Uinta Basin: Coal producing area located in western Colorado and eastern Utah.

units: Refers to both common units and subordinated units.

USFWS: U.S. Fish and Wildlife Service.

volatile matter: Combustible matter which is vaporized in the combustion process. Power plant boilers are designed to burn coal containing specific amounts of volatile matter.

Western Bituminous region: Coal producing area located in western Colorado and eastern Utah.

Western United States: Coal producing area that includes the Powder River Basin, the Western Bituminous region, the Four Corners area and the Uinta Basin.

Wood Mackenzie: Wood Mackenzie Inc.

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BOWIE RESOURCE PARTNERS LP

Common Units
Representing Limited Partner Interests

PRELIMINARY PROSPECTUS

, 2015

Citigroup

Morgan Stanley

Deutsche Bank Securities

UBS Investment Bank

Credit Suisse

Stifel

Brean Capital

Dealer Prospectus Delivery Obligation

Until , 2015 (25 days after the commencement of this offering), all dealers that effect transactions in these securities, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealer's obligation to deliver a prospectus when acting as an underwriter and with respect to unsold allotments or subscriptions.

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PART II

INFORMATION NOT REQUIRED IN THE PROSPECTUS

ITEM 13. OTHER EXPENSES OF ISSUANCE AND DISTRIBUTION.

Set forth below are the expenses (other than underwriting discounts) expected to be incurred in connection with the issuance and distribution of the securities registered hereby. With the exception of the SEC registration fee, the FINRA filing fee and the NYSE listing fee the amounts set forth below are estimates.

SEC registration fee	$ 11,620
FINRA filing fee	15,500
Printing expenses	*
Fees and expenses of legal counsel	*
Accounting fees and expenses	*
Transfer agent and registrar fees	*
NYSE listing fee	*
Miscellaneous	*
Total	*

* To be provided by amendment.

ITEM 14. INDEMNIFICATION OF OFFICERS AND THE DIRECTORS OF THE BOARD OF DIRECTORS OF OUR GENERAL PARTNER.

The section of the prospectus entitled "The Partnership Agreement—Indemnification" is incorporated herein by reference and discloses that we will generally indemnify the directors and officers of our general partner to the fullest extent permitted by law against all losses, claims, damages or similar events. Subject to any terms, conditions or restrictions set forth in the amended and restated agreement of limited partnership, Section 17-108 of the Delaware Revised Uniform Limited Partnership Act empowers a Delaware limited partnership to indemnify and hold harmless any partner or other person from and against all claims and demands whatsoever.

Section 18-108 of the Delaware Limited Liability Company Act provides that a Delaware limited liability company may indemnify and hold harmless any member or manager or other person from and against any and all claims and demands whatsoever. The limited liability company agreement of Bowie GP, LLC, our general partner, provides for the indemnification of its directors and officers against liabilities they incur in their capacities as such. We may enter into indemnity agreements with each of the current directors and officers of our general partner to give these directors and officers additional contractual assurances regarding the scope of the indemnification set forth in our general partner's limited liability company agreement and to provide additional procedural protections.

The underwriting agreement that we expect to enter into with the underwriters, to be filed as Exhibit 1.1 to this registration statement, will contain indemnification and contribution provisions that will indemnify and hold harmless the director and officers of our general partner.

ITEM 15. RECENT SALES OF UNREGISTERED SECURITIES.

In connection with our formation in January 2015, we issued (i) the non-economic general partner interest in us to Bowie GP, LLC and (ii) the 100.0% limited partner interest in us to Bowie Resource Holdings, LLC for $100.00. These issuances were exempt from registration under Section 4(2) of the Securities Act. There have been no other sales of unregistered securities within the past three years.

ITEM 16. EXHIBITS.

See the Exhibit Index on the page immediately preceding the exhibits for a list of exhibits filed as part of this registration statement on Form S-1, which Exhibit Index is incorporated herein by reference.

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ITEM 17. UNDERTAKINGS.

The undersigned Registrant hereby undertakes to provide to the underwriters at the closing specified in the underwriting agreement certificates in such denominations and registered in such names as required by the underwriters to permit prompt delivery to each purchaser.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers and controlling persons of the Registrant pursuant to the provisions described in Item 14 above, or otherwise, the Registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the Registrant of expenses incurred or paid by a director, officer or controlling person of the Registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the Registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.

The undersigned registrant hereby undertakes that, for the purpose of determining liability of the registrant under the Securities Act to any purchaser in the initial distribution of the securities, in a primary offering of securities of the undersigned registrant pursuant to this registration statement, regardless of the underwriting method used to sell the securities to the purchaser, if the securities are offered or sold to such purchaser by means of any of the following communications, the undersigned registrant will be a seller to the purchaser and will be considered to offer or sell such securities to such purchaser:

(1) Any preliminary prospectus or prospectus of the undersigned registrant relating to the offering required to be filed pursuant to Rule 424;

(2) Any free writing prospectus relating to the offering prepared by or on behalf of the undersigned registrant or used or referred to by the undersigned registrant;

(3) The portion of any other free writing prospectus relating to the offering containing material information about the undersigned registrant or its securities provided by or on behalf of the undersigned registrant; and

(4) Any other communication that is an offer in the offering made by the undersigned registrant to the purchaser.

The undersigned Registrant hereby undertakes that:

(1) For purposes of determining any liability under the Securities Act, the information omitted from the form of prospectus filed as part of this Registration Statement in reliance upon Rule 430A and contained in a form of prospectus filed by the Registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this Registration Statement as of the time it was declared effective;

(2) For the purpose of determining any liability under the Securities Act, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at the time shall be deemed to be the initial bona fide offering thereof; and

(3) For purposes of determining any liability under the Securities Act, each prospectus filed pursuant to Rule 424(b) as part of a registration statement relating to an offering, other than registration statements relying on Rule 430B or other than prospectuses filed in reliance on Rule 430A, shall be deemed to be part of and included in the registration statement as of the date it is first used after effectiveness. Provided, however, that no statement made in a registration statement or prospectus that is part of the registration statement or made in a document incorporated or deemed incorporated

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by reference into the registration statement or prospectus that is part of the registration statement will, as to a purchaser with a time of contract of sale prior to such first use, supersede or modify any statement that was made in the registration statement or prospectus that was part of the registration statement or made in any such document immediately prior to such date of first use.

The Registrant undertakes to send to each limited partner at least on an annual basis a detailed statement of any transactions with Bowie GP, LLC, our general partner, or any of its affiliates, and of fees, commissions, compensation and other benefits paid, or accrued to, Bowie Resource Partners LP or its affiliates for the fiscal year completed, showing the amount paid or accrued to each recipient and the services performed.

The Registrant undertakes to provide to the limited partners the financial statements required by Form 10-K for the first full fiscal year of operations of the Partnership.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, as amended, the registrant has duly caused this Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Louisville, State of Kentucky, on June 19, 2015.

BOWIE RESOURCE PARTNERS LP

By: Bowie GP, LLC

By: /s/ JOHANNES H. DREYER

Name: Johannes H. Dreyer
Title: Chief Executive Officer

Each person whose signature appears below appoints Johannes H. Dreyer, James J. Wolff, and Brian S. Settles, and each of them, any of whom may act without the joinder of the other, as his or her true and lawful attorneys-in-fact and agents, with full power of substitution and re-substitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this Registration Statement and any Registration Statement (including any amendment thereto) for this offering that is to be effective upon filing pursuant to Rule 462(b) under the Securities Act of 1933, as amended, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he might or would do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them of their or his or her substitute and substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Act of 1933, as amended, this Registration Statement has been signed below by the following persons in the capacities and the dates indicated.

Signature	Title	Date
/s/ JOHANNES H. DREYER Johannes H. Dreyer	Chief Executive Officer and Director (Principal Executive Officer)	June 19, 2015
/s/ JAMES J. WOLFF James J. Wolff	Chief Financial Officer (Principal Financial and Accounting Officer)	June 19, 2015
/s/ JOHN J. SIEGEL John J. Siegel	Director	June 19, 2015

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EXHIBIT INDEX

Exhibit Number	Description
1.1*	Form of Underwriting Agreement
2.1†	Asset Purchase and Sale Agreement by and between Fossil Rock Fuels, LLC and Fossil Rock Resources, LLC, dated as of December 12, 2014
2.2	Amendment No. 1 to Asset Purchase and Sale Agreement by and between Fossil Rock Fuels, LLC and Fossil Rock Resources, LLC, dated as of June 5, 2015
3.1	Certificate of Limited Partnership of Bowie Resource Partners LP
3.2*	Form of Amended and Restated Limited Partnership Agreement of Bowie Resource Partners LP (included as Appendix A in the prospectus included in this Registration Statement)
4.1*	Form of Registration Rights Agreement
4.2*	Form of Indenture, by and among the Issuers, the Guarantors and , as Trustee
5.1	Form of Opinion of Vinson & Elkins L.L.P. as to the legality of the securities being registered
8.1	Form of Opinion of Vinson & Elkins L.L.P. relating to tax matters
10.1*	Form of Contribution Agreement
10.2	Form of Bowie Resource Partners LP Long-Term Incentive Plan
10.3*	Form of Credit Agreement, by and among Bowie Resource Partners, LP, , as administrative agent and the Lenders party thereto
10.4	Form of Omnibus Agreement
10.5	Form of Coal Supply Agreement by and among BRP Holdings LLC, Canyon Fuel Company, LLC, Fossil Rock Resources, LLC and Bowie Coal Sales, LLC
10.6*	Form of Coal Services Agreement by and among Trafigura AG, BRP Holdings LLC, Canyon Fuel Company, LLC, Fossil Rock Resources, LLC and Bowie Coal Sales, LLC
10.7	Form of Bowie Refined Coal Agreement
10.8	Repayment Agreement (Quitchupah Road), dated as of April 12, 2012 by and between the Sevier Special Service Districts and Canyon Fuel Company, LLC
21.1	List of Subsidiaries of Bowie Resource Partners LP
23.1	Consent of Norwest Corporation
23.2	Consent of Wood Mackenzie Inc.
23.3	Consent of Coulter & Justus, PC
23.4	Consents of Ernst & Young LLP
23.5	Consent of Vinson & Elkins L.L.P. (contained in Exhibit 5.1)
23.6	Consent of Vinson & Elkins L.L.P. (contained in Exhibit 8.1)

24.1 Powers of Attorney (included on page II-4)

99.1 Consent of Director Nominee, John DeRosa

99.2 Consent of Director Nominee, Jesus Fernandez

99.3 Consent of Director Nominee, Carlos Pons

99.4 Consent of Director Nominee, Steve Rickmeier

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* To be provided by amendment.

† The schedules to this agreement have been omitted from this filing pursuant to Item 601(b)(2) of Regulation S-K. The Registrant will furnish copies of such schedules to the Securities and Exchange Commission upon request.

Fossil Rock Fuels, LLC Coal Exploration Drilling

Fossil Rock Fuels, LLC plans to drill 27 coal exploration borings using helicopter assisted and truck mounted units between 2012 and 1014.

Location Summary

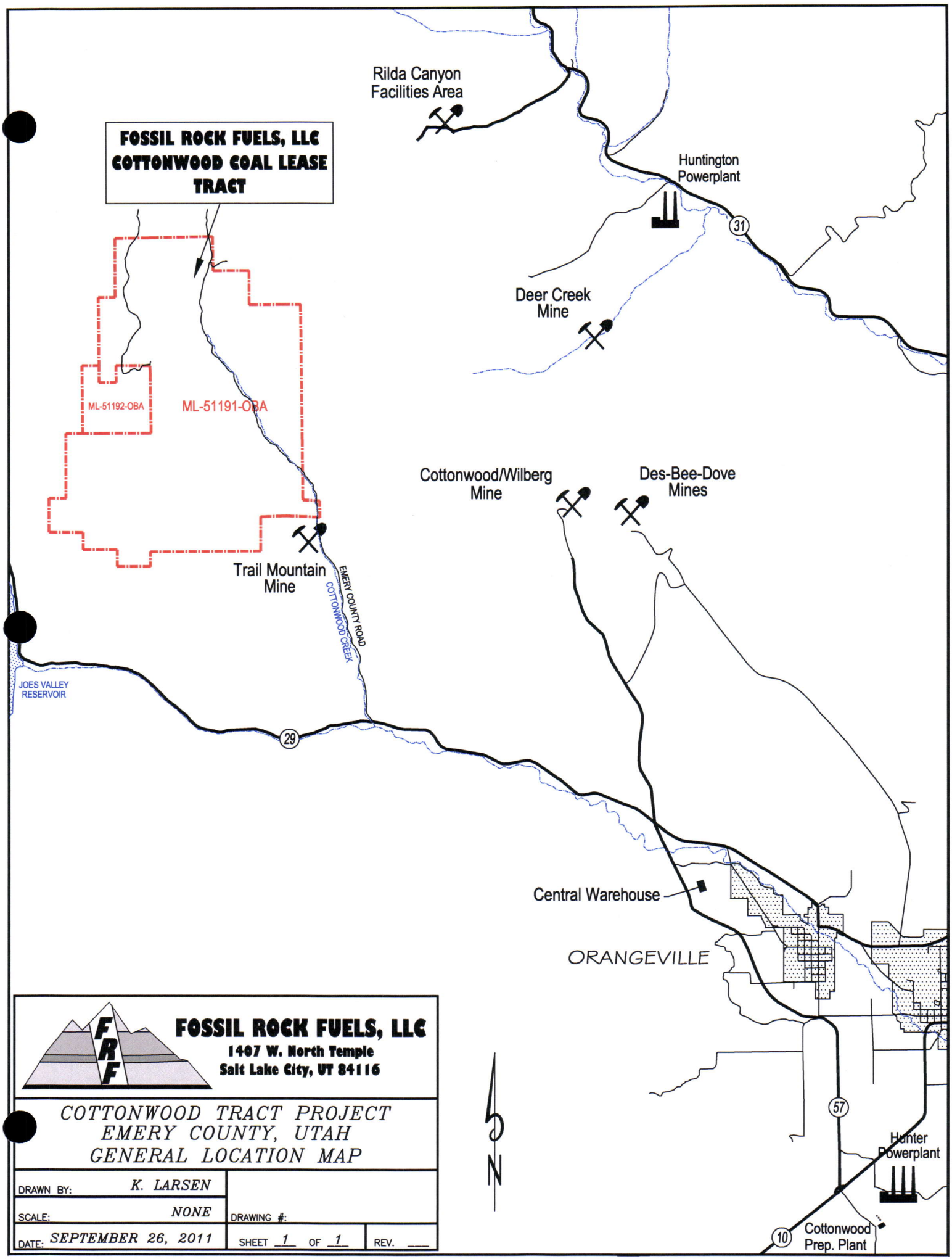
The project area is located northeast of Joe's Valley Reservoir and about 10 miles northwest of Orangeville, UT.

District: Ferron Ranger District

Project Documents

Scoping

Fossil Rock Fuels Scoping Letter (PDF 266kb)
Cottonwood Lease Project Location Map 1 (PDF 491kb)
Project Location Map 2 (PDF 178kb)


FOSSIL ROCK FUELS, LLC
COTTONWOOD COAL LEASE TRACT
Rilda Canyon Facilities Area
Huntington Powerplant
31
Deer Creek Mine
ML-51192-OBA
ML-51191-OBA
Cottonwood/Wilberg Mine
Des-Bee-Dove Mines
Trail Mountain Mine
EMERY COUNTY ROAD
COTTONWOOD CREEK
JOES VALLEY RESERVOIR
29
Central Warehouse
ORANGEVILLE
57
Hunter Powerplant
10
Cottonwood Prep. Plant
N
FOSSIL ROCK FUELS, LLC
1407 W. North Temple
Salt Lake City, UT 84116
COTTONWOOD TRACT PROJECT
EMERY COUNTY, UTAH
GENERAL LOCATION MAP
DRAWN BY: K. LARSEN
SCALE: NONE
DRAWING #:
DATE: SEPTEMBER 26, 2011
SHEET 1 OF 1
REV.

U.S. Energy Information Administration

Coal
Coal Markets

Release date: June 27, 2016 | **Next release date:** July 5, 2016 Archive

Average weekly coal commodity spot prices
dollars per short ton

	Week ending					Week ago
	05/27/16	06/03/16	06/10/16	06/17/16	06/24/16	change
Central Appalachia *12,500 Btu, 1.2 SO_2*	$40.50	$40.50	$40.50	$40.50	$40.50	$0.00
Northern Appalachia *13,000 Btu, < 3.0 SO_2*	$42.10	$42.10	$42.10	$42.10	$42.10	$0.00
Illinois Basin *11,800 Btu, 5.0 SO_2*	$31.70	$31.70	$31.70	$31.70	$31.70	$0.00
Powder River Basin *8,800 Btu, 0.8 SO_2*	$8.80	$8.80	$8.80	$8.80	$8.80	$0.00
Uinta Basin *11,700 Btu, 0.8 SO_2*	$37.50	$37.50	$37.50	$37.50	$37.50	$0.00

Source: *With permission, SNL Energy*
Note: *Coal prices shown reflect those of relatively high-Btu coal selected in each region for delivery in the "prompt quarter." The prompt quarter is the quarter that follows the current quarter. For example, the 2nd quarter is the prompt quarter of a period between January to the end of March. For a period between April to the end of June, the 3rd quarter (July through September) is the prompt quarter. In the row headings, the Btu value represents heat value per pound, and the SO2 value reflects its percentage of total coal weight. The historical spot price data are proprietary and cannot be released by EIA; see SNL Energy. See SNL Energy.*

Average weekly coal commodity spot prices
dollars per mmbtu

	Week ending					Week ago
	05/27/16	06/03/16	06/10/16	06/17/16	06/24/16	change
Central Appalachia *12,500 Btu, 1.2 SO_2*	$1.62	$1.62	$1.62	$1.62	$1.62	$0.00
Northern Appalachia *13,000 Btu, < 3.0 SO_2*	$1.62	$1.62	$1.62	$1.62	$1.62	$0.00
Illinois Basin *11,800 Btu, 5.0 SO_2*	$1.34	$1.34	$1.34	$1.34	$1.34	$0.00
Powder River Basin *8,800 Btu, 0.8 SO_2*	$0.50	$0.50	$0.50	$0.50	$0.50	$0.00
Uinta Basin	$1.60	$1.60	$1.60	$1.60	$1.60	$0.00

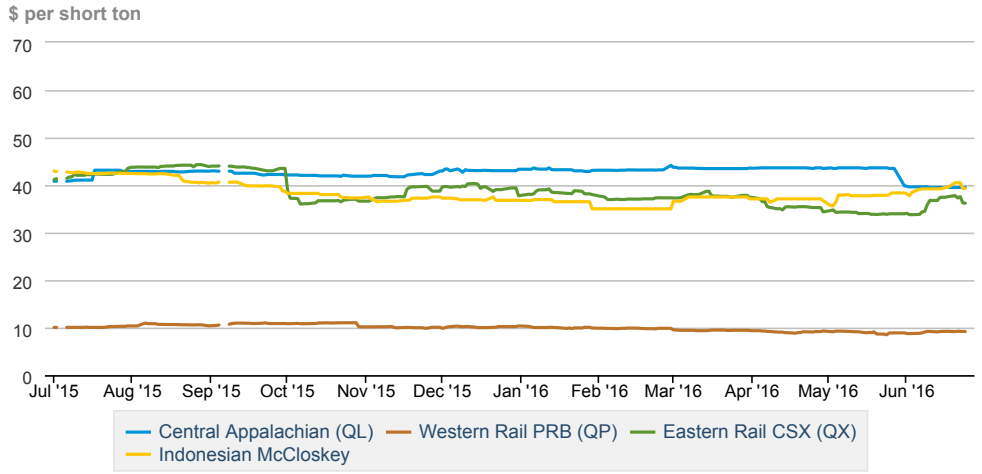
11,700 Btu, 0.8 SO_2

Source: *With permission, SNL Energy*

Note: *Coal prices shown reflect those of relatively high-Btu coal selected in each region for delivery in the "prompt quarter." The prompt quarter is the quarter that follows the current quarter. For example, the 2nd quarter is the prompt quarter of a period between January to the end of March. For a period between April to the end of June, the 3rd quarter (July through September) is the prompt quarter. In the row headings, the Btu value represents heat value per pound, and the SO2 value reflects its percentage of total coal weight. The historical spot price data are proprietary and cannot be released by EIA; see SNL Energy. See SNL Energy.*

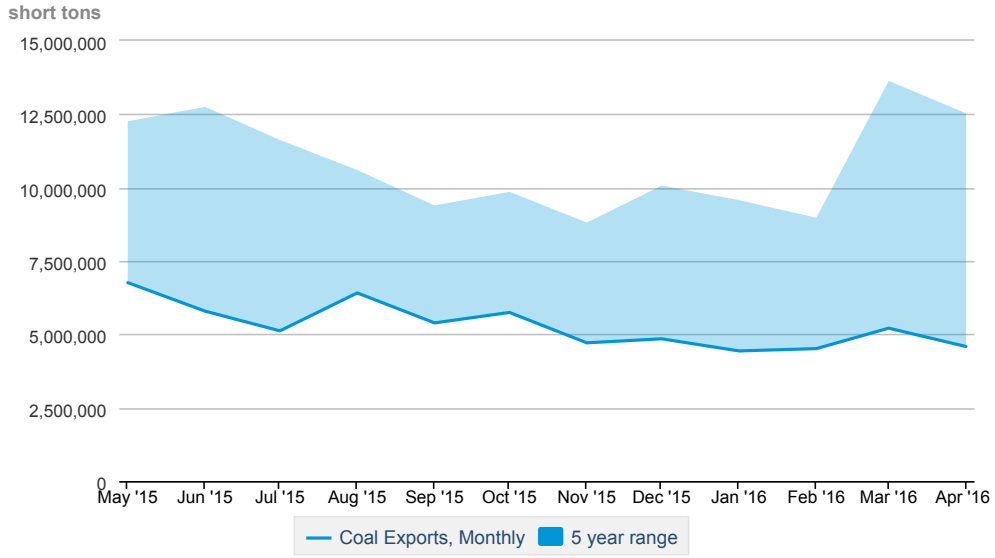
NYMEX coal futures

NYMEX coal futures near-month contract final settlement price



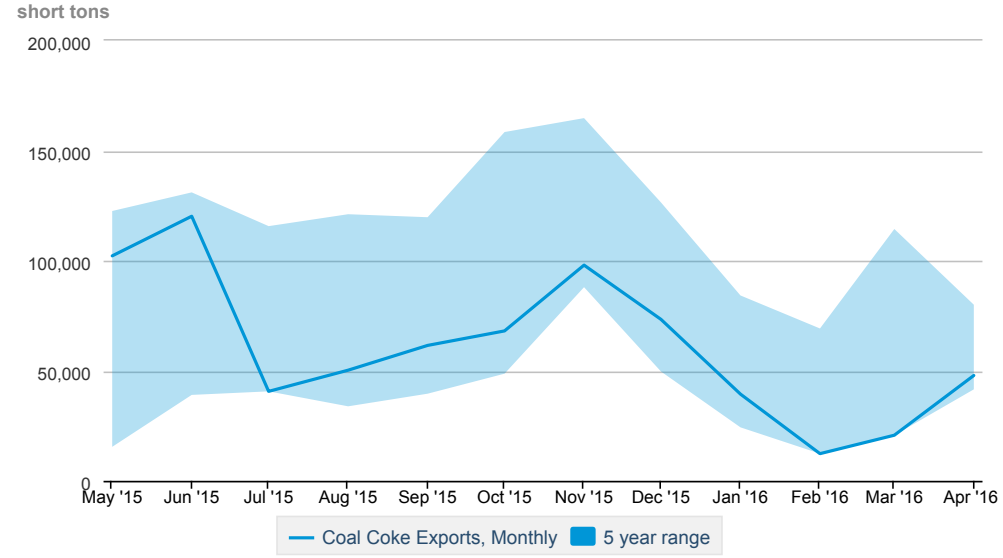
Source: The New York Mercantile Exchange (NYMEX), Daily Energy Bulletin.

Monthly coal exports



Source: U.S. Department of Commerce, Bureau of the Census

Monthly coke exports



Source: U.S. Department of Commerce, Bureau of the Census

U.S. Energy Information Administration

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< Coal Data

Coal Data Browser

Change data set

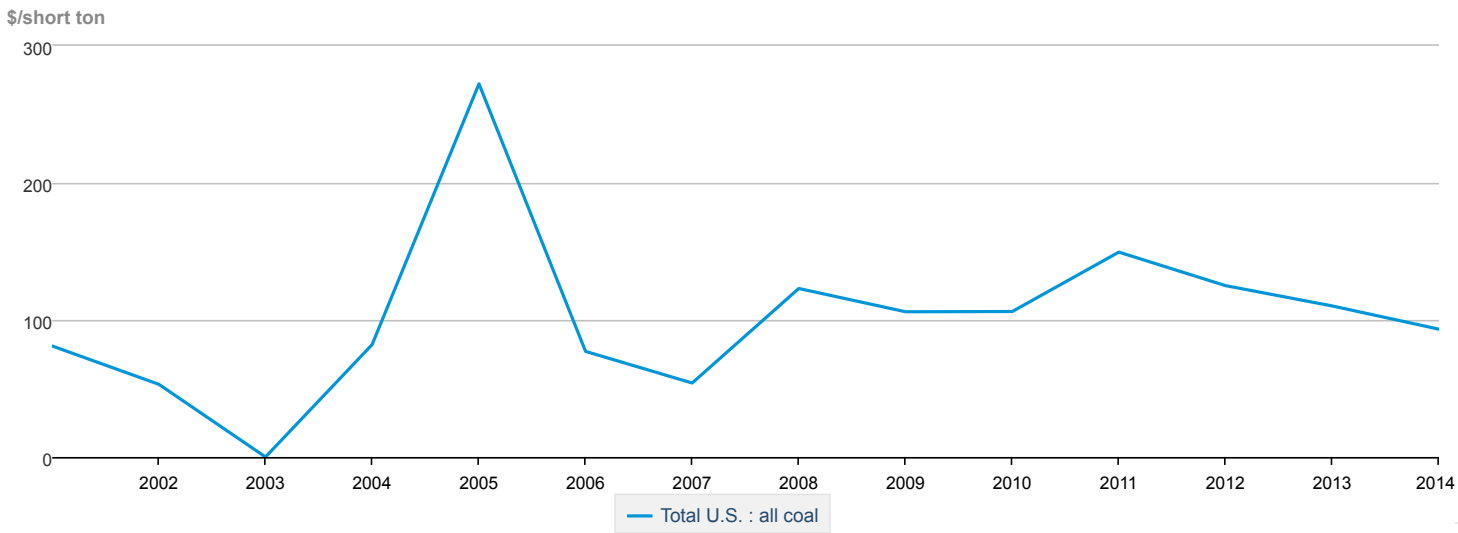
Quantity & price of coal imports & exports

OR

View a pre-generated report

Choose a report

Export price to China, Annual



Source: U.S. Energy Information Administration; Data source: U.S. Census Bureau

Change data set

Quantity & price of coal imports & exports

OR

View a pre-generated report

Choose a report

Import | Export | Quantity | Price | Time-series | Column | U.S. map | HELP | DOWNLOAD

Pin | API

2001 2014

Annual | Quarterly

	2011	2012	2013	2014
Export price to China ($/short ton)				
Total U.S.				
All coal	149.47	125.03	110.18	93.25
Steam coal	97.28	67.15	65.89	50.74
Metallurgical	160.39	151.70	119.98	100.85
Coke	417.97	--	--	575.84
Anchorage, AK				
All coal	--	--	--	--
Steam coal	--	--	--	--
Metallurgical	--	--	--	--

400

All coal	158.25	150.80	101.36	127.43
Steam coal	153.72	85.17	84.06	--
Metallurgical	158.66	158.06	103.56	127.43
Boston, MA				
All coal	--	1,660.83	--	--
Steam coal	--	1,660.83	--	--
Charleston, SC				
All coal	--	--	--	--
Steam coal	--	--	--	--
Chicago, IL				
All coal	--	--	--	--

W = Data withheld to prevent disclosure.

The U.S. coal data is collected and prepared for release by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA). The data are compiled from the following sources: Exports: U.S. Department of Commerce, Bureau of the Census, "Monthly Report 545;" and Imports: U.S. Department of Commerce, Bureau of the Census, "Monthly Report IM 145."

Note that data for the most current time periods typically represent preliminary estimates based on samples collected by the surveys. After the end of a calendar year the estimates are replaced by actual values from a final data collection, except in the case of missing values. Missing values (non-response) is typically minimal. Normally all data are final by the fall following the data collection year (e.g., data for 2012 should be final by the fall of 2013).

For more information concerning EIA's quarterly data collection and estimation, see the individual footnotes contained in the Quarterly Coal Report (http://www.eia.gov/coal/production/quarterly/).

Terms and definitions

U.S. Energy Information Administration

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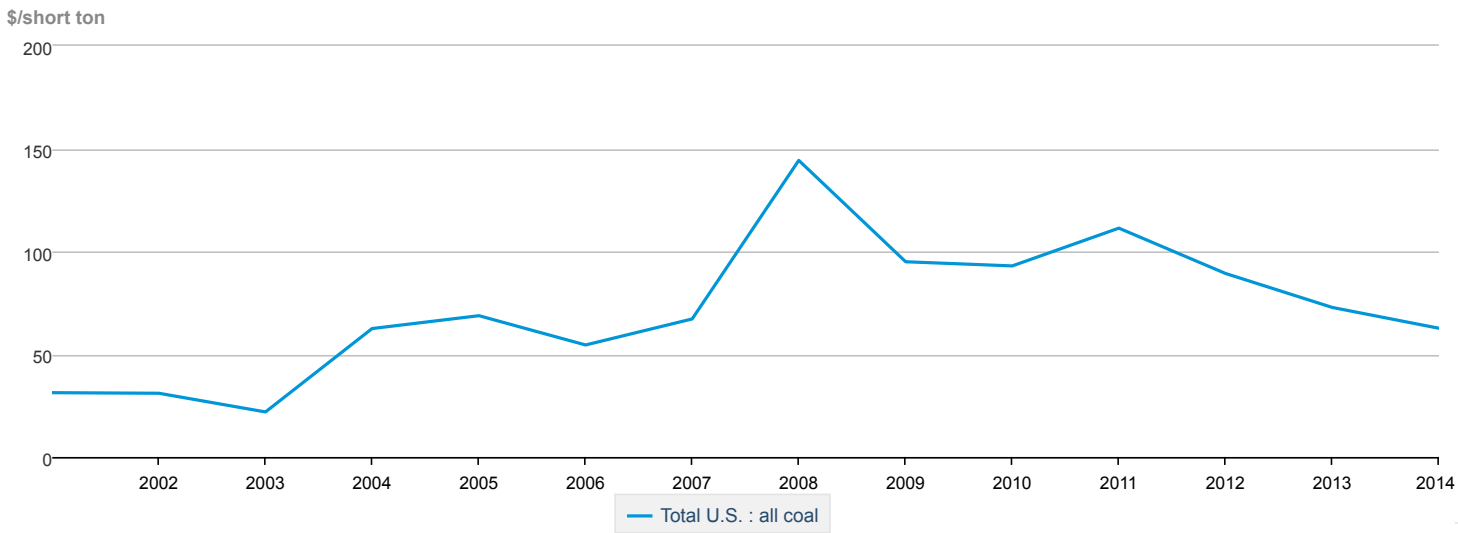
< Coal Data

Coal Data Browser

Change data set OR **View a pre-generated report**

Quantity & price of coal imports & exports | Choose a report

Export price to South Korea (Republic Of Korea), Annual



Source: U.S. Energy Information Administration; Data source: U.S. Census Bureau

Change data set OR **View a pre-generated report**

Quantity & price of coal imports & exports | Choose a report

Import | Export | Quantity | Price | Time-series | Column | U.S. map | HELP | DOWNLOAD

Pin | API

2001 2014

Annual | Quarterly

	2011	2012	2013	2014
Export price to South Korea (Republic Of Korea) ($/short ton)				
Total U.S.				
All coal	111.31	89.28	72.73	62.61
Steam coal	46.71	34.92	41.31	42.79
Metallurgical	179.92	137.66	107.60	92.27
Coke	796.82	691.82	923.62	851.06
Anchorage, AK				
All coal	30.14	30.77	35.97	29.38
Steam coal	30.14	30.76	35.96	29.35
Metallurgical	--	113.42	110.48	114.19

All coal	161.58	130.22	95.35	90.54
Steam coal	108.48	77.11	85.90	84.15
Metallurgical	173.30	133.96	100.26	92.38
Chicago, IL				
Coke	--	--	--	--
Cleveland, OH				
All coal	--	145.15	--	--
Steam coal	--	145.15	--	--
Coke	--	--	--	--
Los Angeles, CA				

W = Data withheld to prevent disclosure.

The U.S. coal data is collected and prepared for release by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA). The data are compiled from the following sources: Exports: U.S. Department of Commerce, Bureau of the Census, "Monthly Report 545;" and Imports: U.S. Department of Commerce, Bureau of the Census, "Monthly Report IM 145."

Note that data for the most current time periods typically represent preliminary estimates based on samples collected by the surveys. After the end of a calendar year the estimates are replaced by actual values from a final data collection, except in the case of missing values. Missing values (non-response) is typically minimal. Normally all data are final by the fall following the data collection year (e.g., data for 2012 should be final by the fall of 2013).

For more information concerning EIA's quarterly data collection and estimation, see the individual footnotes contained in the Quarterly Coal Report (http://www.eia.gov/coal/production/quarterly/).

Terms and definitions

EMERY COUNTY

Keith Brady <keithb@emery.utah.gov>

FW: Update Memo and Term Sheet

2 messages

Holt, Jeff <jeff.holt@bmo.com> Wed, Mar 25, 2015 at 9:56 PM
To: "Jae Potter (jae.potter@carbon.utah.gov)" <jae.potter@carbon.utah.gov>, "Casey Hopes (casey.hopes@carbon.utah.gov)" <casey.hopes@carbon.utah.gov>, Jake Mellor <jake@mellorfinancial.com>, "Gary Mason (gmason@sevier.utah.gov)" <gmason@sevier.utah.gov>, "Garth \"Tooter\" Ogden (togden@sevier.utah.gov)" <togden@sevier.utah.gov>, "Gordon Topham (gtopham@sevier.utah.gov)" <gtopham@sevier.utah.gov>, "claudiaj@cut.net" <claudiaj@cut.net>, "keithb@emery.utah.gov" <keithb@emery.utah.gov>, "Malcolm Nash (mrnash@sevier.Utah.gov)" <mrnash@sevier.utah.gov>
Cc: "Hashimoto, Emily" <Emily.Hashimoto@bmo.com>, Jim Burr <burr@chapman.com>

Please Keep these confidential between the Counties involved.

Jeff holt

Jeffrey D. Holt

Managing Director

BMO Capital Markets Inc.

415-828-4396

This e-mail and any attachments may contain confidential and privileged information. If you are not the intended recipient, please notify the sender immediately by return e-mail, delete this e-mail and destroy any copies. Any dissemination or use of this information by a person other than the intended recipient is unauthorized and may be illegal. Unless otherwise stated, opinions expressed in this e-mail are those of the author and are not endorsed by the author's employer

3 attachments

Bulk Export Terminal Term Sheet.docx
107K

March 26 Update Memorandum.docx
121K

US West Coast Multi Commodity Bulk Terminal - Teaser (March 2015) - v14.pdf
45K

Keith Brady <keithb@emery.utah.gov> Thu, Mar 26, 2015 at 11:30 AM
To: Ethan Migliori <EthanM@emery.utah.gov>, Paul Cowley <paulc@emery.utah.gov>

Please keep confidential. Here is the info regarding the Rail/Port, CIB, and the interlocal agreement.

Sincerely,

Keith Brady
Emery County Commissioner
480-239-7931
[Quoted text hidden]

---

3 attachments

Bulk Export Terminal Term Sheet.docx
107K

March 26 Update Memorandum.docx
121K

US West Coast Multi Commodity Bulk Terminal - Teaser (March 2015) - v14.pdf
45K

Preliminary Term Sheet
Multi-Commodity Bulk Export Terminal

- Terminal is located at Oakland Army Base
  - 30 acres
  - The site is a 66-year leasehold with the City of Oakland.
  - 50+2 - feet draft at the berth and in the channel
  - Rail access from UP and BNSF main lines
  - all railcar, loading, storage and conveyor facilities will be covered
  - will handle 9.5mm metric tons of bulk product per year, both white products (soda ash, potash, salt) as well as black product (coal) –
  - Coal not to initially exceed 49% of throughput on an annual basis – (internal policy only, not restricted by permits)
  - Terminal cost = $275mm
    - $50mm preferred equity
    - $200mm in debt (private placement)
    - $25 mm from local California sources (for site prep and some waterfront infrastructure).
  - The Terminal is (almost?) fully permitted
    - requires construction permits from the City of Oakland which are "administrative" only.
    - One BCDC permit on terminal design
    - the terminal was and always has been a bulk terminal

- Bowie Resource Partners (BRP) will be the Series A shareholder and will contribute throughput guarantees sufficient to secure $200 million in (un-rated) project debt.
- The Utah Counties will contribute $50mm in return for
  - 10% annual return
    - return is preferred
    - return is cumulative
  - throughput allocations in the terminal for commodities coming from Utah Counties
    - 49% of terminal throughput capacity
    - [Can we get more? Or do they need to assign the rest of the capacity to other parties get the $200 mm in debt placed?]
- County Partners in the terminal
  - Carbon– Lead [33%]
  - Sevier - [30%]
  - Sanpete – [12%]
  - Emery – [25%]
- The four Counties will apply to the CIB for a single $53,000,000 grant on April 1 to fund their contribution to the terminal and to secure the throughput allocations.
  - Proceeds to Terminal - $50,000,000
  - Expenses [up to $3mm]

- In return for the equity investment, the Utah Counties will be allocated [49]% of the throughput capacity in the terminal. Details on how that allocation would initially be divided and assigned between producers is TBD. Presumably Bowie will get the throughput allocations to their mines in the Counties, at least for some number of years.

- The terminal Operator, TLS will be created as a part of the business arrangement between the Counties, Bowie, and any other users that can be contracted ahead of time, and will own a 66-year operating concession on the terminal from the City of Oakland.

- BRP and the Counties, through their terminal operator, TLS, will work to negotiate and sign a construction agreement with Phil Tagami's CCI Group to complete the full design of the terminal and to then build the terminal.

    - The Counties will receive a quarterly return on their allocation contribution, on a preferred basis, out of the net income of the terminal operations, beginning on start of terminal operations. The return payment to the Counties will be preferred and will come ahead of all other distributions of profits. Such return payment will include:
        - TBD [per ton or fixed payment].
        - Such return payment is targeted to provide an annual cash-on-cash return of 10%, beginning at the start of operations.

- The Counties will form an interlocal agency within which they will decide the throughput allocations from time to time in consultation with BRP and the terminal operator, TLS.

- BRP and the Counties agree that the parallel investment in the new Sevier Railroad facility will be required in some fashion and will be cross-linked in order to assure that the railroad and the terminal will both be built.

- CIB Loan

    - The Counties, on behalf of the Interlocal Agency will work aggressively to bring a request for $50,000,000 (plus $3,000,000 in expenses) for the terminal project to the CIB for their April 2nd meeting.
    - Securing the $50,000,000 will demonstrate the legitimacy of the Counties as partners in large infrastructure, and will allow the project to seek and secure an additional $200,000,000 in project debt.
    - The CIB loan will be for 30 years at 2%, with payments to start only upon start of commercial operation of the terminal.
    - The CIB loan will be made to the Interlocal Agency formed by the Counties and the obligation will be non-recourse to the Counties.

- The Counties contribution will be convertible into [49%] of the proceeds from any sale of the terminal leasehold (only with the Counties approval – and presumably will all allocations to the Counties lock in for the duration of the Terminal Lease).

Memorandum
To: Carbon, Sevier, Sanpete, and Emery Counties
From: Jeff Holt, BMO Capital Markets Inc.
CC: Jim Burr

Date: 3/25/2015

Commissioner Potter suggested that I update the group on the progress on the Terminal Project.

- All the counties have had at least one representative visit the bay area to see the old bulk terminal that will be built into a new bulk terminal and to hear CCIG's (California Capital Investment Group) plans for the terminal lease to TLS (Terminal Logistics Solutions).
    - Carbon – Casey Hopes, Jae Potter and Jake Mellor
    - Sevier – Gary Mason, Tooter Ogden, Gordon Topham, Malcolm Nash
    - Sanpete – Claudia Jarrett
    - Emery – Keith Brady
    - Technical Team – Jeff Holt, Jim Burr
- Briefings for Senator Okerlund, Lt. Governor Cox and some members of the CIB are scheduled over the next few days.
- The request to CIB for funding has been submitted and the line item appears in the April 2nd agenda, which is not yet public but which includes $53,000,000 for the terminal project ($50,000,000 in investment proceeds and $3,000,000 in legal expenses, outside technical experts doing diligence on the project, advisory fees, and transaction costs).
    - A few Commissioners have asked about committing the funding now, when the full details of the Terminal partnership are not yet final, or in some cases, not yet determined. The commitment of funding from CIB is strictly to the four Counties (Carbon, Sevier, Sanpete and Emery), for a possible investment in the Terminal when and if the Counties finally conclude their structuring of the transaction and all negotiations relating to such. The CIB commitment only commits the funding to the four counties. It does NOT commit funding to the Terminal Partnership directly. Funding can only be committed by the four counties when and if the four Counties, acting through the Five County Infrastructure group (interlocal agency) have determined that the investment criteria are all final and to their satisfaction (which probably won't happen until sometime in June.)
    - The funding to the Counties is necessary now to show the debt investors in the terminal and the lessor of the land (CCIG) that the Counties are legitimate partners (with funds in hand) and committed to working through negotiations to a financial close, based on the business and legal terms that are concluded to the satisfaction of the Counties. The project partners spending all their money to advance the project needed to know that the Counties' funding is real.

- As you all know, the urgency of the CIB request is to allow the Terminal Project to be accomplished (financial close) prior to the expiration of TLS' option on the terminal site in July.
- The Private Sector Partner has clearly said that without the Terminal, they have no interest in guaranteeing throughputs on the railroad. Without the throughput guarantees from the Private Sector Partner, rail feasibility is unlikely. These two projects must be contractually linked in the negotiations.
- Many things need to be done prior to the commitment of the funds from the Counties to the Project:
    - Creation of the Five (or four if Juab does not want to join) County Group.
        - With two Projects on the group's program:
            - Multi-Commodity Bulk Export Terminal
                - Four of the five Counties participating.
                - Tentative percentages as follows:
                - Carbon – 33%
                - Sevier – 30%
                - Sanpete – 12%
                - Emery – 25%
            - Railroad from Levan to Salina
                - Three of the five Counties participating.
                - Tentative percentages as follows:
                - Sevier – 70%
                - Sanpete – 15%
                - Juab – 15%
            - Approval by the respective Counties
    - Business Terms to be negotiated between April 2 and July 1. Current Draft of the Counties' Term sheet is attached. Please review and raise any comments.
- A draft of the CIB presentation will be circulated in the coming days.
    - Sevier (a Commissioner), Carbon (Casey Hopes), and Emery (Keith Brady) should all be at the table. Additionally, Jeff Holt from BMO, as the Strategic Infrastructure Advisor to the Counties and Jim Burr from Chapman and Cutler will be at the presenting table. Jeff Holt will take the lead on the presentation to the Board. We are still discussing whether Mark McClure from CCIG should attend to answer any questions the CIB may have about the terminal development.

Deep Draft West Coast Multi-Commodity Bulk Terminal

Project Highlights

Project Overview: Construction of a multi-commodity bulk handling marine terminal on the US West Coast

- Covered facility will reduce exposure to elements and enhance product quality for tenants' commodities
- Dome option allows for separate storage of different quality specs and blends

Asset Highlights: Air Quality and other key permits for the marine terminal are in place for all bulk commodities

- 50 foot draft provides a competitive advantage by reducing the per-ton shipping cost for bulk commodities
  - Panamax vessels can be fully loaded and cape-size vessels can be loaded to approximately 140,000 tons
  - Expands the market reach for regional bulk exporters
- Terminal jointly served by UP and BNSF, offering customers single rail service from virtually all Western US origins
- Proximity to open ocean generates significant value by lowering transit days
- The Project has received broad Governmental support

Project Economics: The Project will include multiple tenants with volume commitments

- Anchor tenant to provide a throughput pledge of approximately four million tons, sufficient to ensure about 2x stabilized EBITDA/Interest coverage
- Project should generate in excess of $40 million of stabilized EBITDA
- Revenue Consultant currently producing market projections
- Discussions with other prospective tenants are advanced

Borrower: The terminal operating company for the Project

ASSET SUMMARY

Location	West Coast, U.S.
Berths	2 berth
Terminal Acreage	~20 acres
Loading Rate	~9,000 tph
Depth	50 feet
Vessels Permitted	Panamax and Cape-Size
Capacity Estimate	9 mtpa
Project Size	~$250 million
Planned Debt for Project Construction	$175-200 million

Proposed Project Timeline

Project Design and Planning	Funding Commitments Required	Construction Begins	Terminal Operation Commences
March 2015	**May 2015**	***August 2015***	**July 2017**

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FAQ

TLS

Frequently Asked Questions

What is Terminal Logistics Solutions?

Terminal Logistics Solutions (TLS) is an Oakland-based company comprised of the foremost experienced professionals in maritime transportation and operations as well as trade and logistics.

TLS is committed to operating the world's most innovative, efficient and environmentally sustainable multiple bulk commodities marine terminals.

TLS seeks to promote economic development in the communities in which it operates, while maximizing workplace safety, terminal volume throughput and customer satisfaction.

TLS' leadership team includes Jerry Bridges, President and CEO, and Omar Benjamin, Vice President. Bridges has been an Oakland resident for 19 years and brings more than 30 years of experience in maritime transportation and operations. Benjamin has more than 25 years of international public and private sector experience in investment, development, trade and logistics, infrastructure, commercial real estate, mixed-use and waterfront real estate.

What is TLS' role in the Oakland Global Trade and Logistics Center?

TLS will provide world-class terminal and stevedoring services at the TLS Multi-Commodity Bulk Terminal, which is a part of the West Gateway section of the Oakland Global Trade and Logistics Center (Oakland Global). Oakland Global is the result of a decade and a half of strategic planning and will become a world-class hub and international gateway for transporting goods by seaport, railroad and roadway.

OBOT will use state-of-the-art practices and procedures to facilitate the moving of cargo directly between ships and rail for a variety of bulk agriculture and mineral commodities.

What is the current status of TLS?

TLS is currently conducting project feasibility and due diligence. Conceptual project design is

also underway.

Operations are projected to begin in 2018.

What is the capacity of TLS?

TLS will be designed to handle an annual throughput of 9,500,000 metric tons of bulk agriculture and mineral commodities and receive up to three unit trains of 114 rail cars per day.

The terminal will be designed to accommodate Handymax (30,000 tons) to Capesize (130,000) vessels utilizing two state-of-the-art fully enclosed shiploaders.

What commodities will be shipped through TLS?

To feasibly operate and meet established expectations of the bulk-shipping market, a terminal must have the ability and capacity to handle any of the more than 15,000 commodities legally shipped throughout the world. At this time, no single commodity has been committed to or excluded.

Who will provide rail service for TLS?

Rail service will be provided by Union Pacific and Burlington Northern Santa Fe in combination with Oakland Global Rail Enterprise (OGRE) who will provide last mile local rail services.

Will TLS impact the environment in the Oakland area?

Environmental stewardship is a top priority for TLS. TLS will be designed, built and operated to meet and/or exceed the project's California Environmental Quality Act (CEQA) requirements, as well as, applicable federal and state approvals.

Additionally, air quality mandates set by TLS will be stricter and more tightly monitored and enforced than current standards, resulting in better air quality for the Oakland area. Air quality and emissions related to Port operations in and around West Oakland will be improved under TLS operating standards.

At all times, all operations and commodities processed at TLS will be subject to and in compliance with federal, state, regional and local laws and regulations. TLS is subject to more than 660 mitigation mandates and conditions of approval by the City of Oakland and the Port of Oakland, including the establishment of a strict air quality regimen in compliance with regulations of the Bay Area Air Quality Management District.

TLS is committed to innovation and leverages all opportunities to improve our

environmental standards. All commodities shipped through the TLS Multi-Commodity Bulk Terminal will:

- Be transported from origin to the terminal in innovative, specially designed covered rail cars;
- Be discharged from the covered rail cars into an enclosed underground unit with dust control/collection technology;
- Be moved within the terminal in enclosed conveyance systems with dust control/collection technology;
- Be stored within enclosed dome storage unit(s) with dust control/collection technology; and,
- Be loaded onto the vessel using enclosed state-of-the-art ship loaders with dust control/collection technology.

Additionally, the terminal will have air quality and other environmental monitors installed with results available to the public.

What about greenhouse gas (GHG) emissions?

TLS is committed to environmental protection. TLS and Oakland Global commend and embrace California and Oakland's commitment to lead by example and set extraordinary GHG emissions reduction mandates for the state. The project's operations will set the standard for compliance with those mandates.

Is the TLS project good for the community?

When the Oakland Army Base closed in 1999, it dismantled a national maritime asset, an economic engine, and a major job generator for the City of Oakland. 5,000 regional jobs were lost as well as 2,000 civilian/military jobs. Oakland was left with decaying, outdated infrastructure, including 93 non-conforming buildings, 4.6 million square feet of obsolete warehouse and 255,000 square feet of unused office space.

Oakland Global will revitalize the Oakland waterfront through job creation and world-class environmental and safety standards, and TLS is a proud partner in this endeavor.

Oakland Global has established an unprecedented community benefits package, including:

- 50% local contracting (more than half of total public infrastructure improvements contract value has been awarded to certified local and small local companies);
- 50% local hours (at least half of horizontal and vertical construction work hours, by contractor and by craft, will be performed by Oakland residents);

- 50% local hire (once the vertical development is complete, at least half of on-going operations workforce will be residents, with a hiring prioritization for West Oakland residents); and,
- Creation of West Oakland Community Jobs Resource Center.

Oakland Global will sustain and create thousands of new jobs in a region that has historically been impacted by nearly 17 percent unemployment.

Once fully built-out, the Oakland Global is projected to create 11,970 jobs, including:

2,686 project construction jobs;

2,724 indirect and induced construction jobs;

2,335 permanent operations jobs; and,

4,225 indirect and induced ongoing jobs.

The fully built-out Oakland Global will produce up to $300 million annually in regional employment income.

TLS is in the process of investing over $250 million for the proposed 66 year life of the project to make those benefits a reality and to generate:

- a construction payroll of $76 million, and
- annual and induced payrolls of $120 million

Upon completion, the Port of Oakland will solidify its positions as the economic engine to drive Oakland's economy forward for decades to come.

What are TLS' health and safety standards?

The health and safety of our workers is our number one priority, and we emphasize health and safety in all aspects of our workplace.

All workplace health and safety practices and procedures will be designed and implemented in partnership with the Union Labor using industry best practices.

What is the relationship between CCIG and Terminal Logistics Strategies ("TLS")?

CCIG has entered into exclusive negotiating agreements with potential future operators of OBOT, the most recent of which is TLS. TLS currently has an exclusive option agreement to become the operator of OBOT and is exploring potential customers and operations as it considers whether to exercise the option. Beyond that contractual link, there is no legal relationship between CCIG and TLS. TLS is not a subsidiary or other part of CCIG. CCIG does

not hire TLS employees.

Contact us at info@tlspops.com or at
510-908-6270

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Parallax One (https://themeisle.com/themes/parallax-one/)powered by WordPress (http://wordpress.org/)

Coal Cars

Thermal Coal

Rotary Aluminum Gondola

All specifications are approximate and may vary between car builders and car owner specifications.

Specifications Table	Diagram
Coupled Length	53.1 ft
Net Carrying Capacity	121 tons
Gross Weight on Rail	143 tons
Door Actuation	N/A

Aluminum Bottom Discharge

All specifications are approximate and may vary between car builders and car owner specifications.

Specifications Table	Diagram
Coupled Length**	53.1 ft
Net Carrying Capacity	117 tons
Gross Weight on Rail	143 tons
Door Actuation	Remote Air Activated Release

**** Required length for rotary gondolas but only required for bottom discharge equipment if equipped with rotary couplers.

Steel Manual Hopper

All specifications are approximate and may vary between car builders and car owner specifications.

Specifications Table	Diagram
Coupled Length**	53.1 ft
Net Carrying Capacity*	102 tons
Gross Weight on Rail*	131.5 tons
Door Actuation	Manual Door Release

* Majority of steel equipment in coal service is restricted to 131.5 gross weight on rail. Some recently built equipment is capable of 143 tons.

** Required length for rotary gondolas but only required for bottom discharge equipment if equipped with rotary couplers.

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Rail Accident Investigation Branch

Rail Accident Report

Autumn Adhesion Investigation
Part 3: Review of adhesion-related incidents
Autumn 2005

Department for Transport

Report 25 (Part3)/2006
January 2007

This investigation was carried out in accordance with:

- the Railway Safety Directive 2004/49/EC;
- the Railways and Transport Safety Act 2003; and
- the Railways (Accident Investigation and Reporting) Regulations 2005.

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Review of adhesion-related incidents during Autumn 2005

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Introduction

1 The sole purpose of a Rail Accident Investigation Branch (RAIB) investigation is to prevent future accidents and incidents and improve railway safety.

2 The RAIB does not establish blame, liability or carry out prosecutions.

3 This report contains the findings of the RAIB investigation into the causes of adhesion related station overrun and Signal Passed At Danger (SPAD) incidents during autumn 2005.

4 The investigation examined:

- data on adhesion performance for the years 2000, 2004 and 2005;
- relevant Railway Group Standards (RGS);
- data from specific adhesion-related incidents;
- research on adhesion-related subjects from the UK and abroad;
- other information on adhesion-related issues supplied by the parties identified below.

5 For the purposes of this investigation, access was freely given by the following organisations to their staff, data and records:

- Network Rail;
- *Train Operating Companies* (South Eastern Trains[1], Southern Railway, South West Trains (SWT), c2c, Merseyrail and First ScotRail);
- *Rail Safety and Standards Board* (RSSB), who provided information from their research programme and data on adhesion-related incidents;
- train owners (Angel Trains, HSBC and Porterbrook);
- train manufacturers (Bombardier and Siemens);
- train equipment manufacturers (Knorr Bremse);
- AEA Technology who provide services to the railway industry in evaluating the performance of rolling stock;
- Interfleet in their role as a *Vehicle Acceptance Body* (VAB).

6 In addition, RAIB has consulted and exchanged information with the *Adhesion Working Group* (AWG), a cross-industry body that has also been investigating the causes of adhesion-related incidents in autumn 2005. The AWG has prepared a report, which was reviewed by RAIB during the course of its own investigation.

[1] Train services in Kent are now operated by 'Southeastern', the successor organisation to South Eastern Trains. As the latter operated services during Autumn 2005 and were consulted by the RAIB during the course of this investigation this report makes reference to South Eastern Trains where appropriate.

7 Appendices at the rear of this report contain:

- a glossary of acronyms and abbreviations (Appendix A);
- explanation of certain technical terms (shown in italics the first time they appear within the body of this report) (Appendix B);
- a list of relevant RGS current in autumn 2005 (Appendix C);
- an overview of magnetic brakes, which is a technology for stopping trains that is not used on main line railways in this country, but is used in other European countries (Appendix D);
- a comparison between the recommendations from the investigation undertaken by the AWG into adhesion-related incidents in autumn 2005 and the recommendations from this report (Appendix E).

8 Two terms are used throughout this report, 'wheelslide', and 'slip':

- **Wheelslide** refers to problems experienced by trains during braking, when wheel rotational speed is slower than the actual speed of the train. The extent of wheelslide can vary from 1-2% (wheels rotating at a slightly lower speed than the train's actual speed) through to 100% (wheels locked when train is moving). The converse issue during acceleration, when low adhesion can cause wheel rotational speed to be higher than actual train speed is referred to as 'wheelspin'. This report is only concerned with adhesion problems during braking.
- **Slip** refers to the parameters within which a *wheelslide prevention (WSP) system* permits train wheels to rotate below the real speed of the train (extent of slip). WSP systems are provided on trains to limit the extent of wheelslide and wheelspin by modulating braking or tractive effort. In braking, most modern WSP systems permit slip values up to a maximum of 20% of real speed before intervening to release brakes and allow wheel rotational speed to build up towards the real speed of the train.

9 Reference is also made in the report to levels of adhesion between wheel and rail. This is normally expressed as a coefficient of friction (symbol μ). The lower the value of μ, the lower the adhesion between wheel and rail. Typical values for μ for dry rail would be at least 0.20. In wet weather, this can fall to 0.10. Under severe low adhesion conditions, the value of μ can drop below 0.03. As trains rely on the coefficient of friction between wheel and rail to stop, the level of adhesion available is critical to the rate at which the train can decelerate. Many modern trains have four or five fixed braking rates available to the driver, the lowest of which will normally achieve a deceleration rate of $0.3m/s^2$ and the highest a rate of at least $1.2m/s^2$. Although the relationship is not exact, a braking rate of $0.3m/s^2$ can only be achieved if the value of μ is at least 0.03. The value of μ would need to be at least 0.12 to achieve an emergency braking rate of $1.2m/s^2$.

Summary of the report

Key facts about adhesion performance during autumn 2005

10 The immediate cause of the SPAD incidents that occurred at Esher on 25 November 2005 and Lewes on 30 November 2005 (which are the subject of Parts 1 and 2 of this investigation report) was poor adhesion between wheel and rail. Both trains involved had failed to stop within normally expected distances, despite the systems on the train performing in accordance with their specifications and the drivers correctly implementing the *professional driving policy* prevailing within the relevant Train Operating Company (TOC) at the time. Both trains had travelled a distance of approximately 3km from the time that the driver had first applied the brake. Stopping distances under normal circumstances would have been less than 2km.

11 These two incidents occurred against a backdrop of an increase in the number of adhesion-related SPAD incidents and a significant increase in the number of adhesion-related station overrun incidents on the national rail network during autumn 2005, as compared with autumn 2004:

	AUTUMN 2004	AUTUMN 2005
Adhesion-related SPADs	7	9
Adhesion-related station overruns	152	390

Figure 1: Adhesion-related SPAD and station overrun incidents - autumn 2004 and autumn 2005.

12 The purpose of this investigation has been to establish the causes of this increase in adhesion-related incidents in autumn 2005 and by so doing, identify ways in which short, medium and long-term performance can be improved.

Risk from adhesion-related incidents

13 When viewed from a historical perspective, the risk from adhesion-related incidents can be characterised as high in frequency but low in consequence. There have been very few accidents arising from low adhesion. The most significant adhesion-related accident occurred in November 1985, when two trains collided at Copyhold Junction in Sussex resulting in 40 people being injured, 11 of them seriously. Another low-adhesion accident occurred in November 1994 when a train ran into the buffer stops at Slough, causing the driver serious injuries.

14 However, the two near-miss incidents at Esher and Lewes in autumn 2005 demonstrate that the potential exists for a serious accident to result from low adhesion conditions. There were 6 incidents (including the Esher SPAD) where the length of the overrun exceeded 1000 metres and 18 incidents where the overrun was so severe that the driver continued to the next station rather than returning to the station that had been passed. There is scope for further action to address the risk arising from these severe incidents.

15 Based on historical experience, although adhesion-related incidents have rarely resulted in an accident, should an accident occur, the most probable outcome is a collision if a train fails to stop at a signal or derailment if a train runs through facing points at excessive

speed or fails to stop at a signal where *trap points* are located immediately beyond. While modern rolling stock has a high standard of crashworthiness, a train collision has the potential for fatalities and injuries. Train derailments at low speed may not carry the same potential for fatality and injury, but they can also lead to collisions if the derailed train obstructs an adjacent line.

Immediate causes, contributory factors and issues of concern

16 There is no single immediate cause of the increase in adhesion-related station overrun and SPAD incidents during autumn 2005. However, there are a number of causal factors:

- Significant lengths of low adhesion were experienced on a number of occasions during autumn 2005 and it is possible that they are now occurring more frequently than has been previously thought to be the case.
- A method for identifying low adhesion areas that was biased towards historical data rather than current conditions or risk.
- Different methods of rail head treatment being employed across the network, arising from uncertainty over the optimum method.
- Inconsistent performance in the prediction of days when the risk of low adhesion incidents was high.
- The application of sand is one of the most effective ways of modifying the level of adhesion available to trains experiencing difficulties. However, not all units are equipped with the facility to lay sand and some are specifically excluded by RGS GM/RT2461.
- The guidance value of 2kg/minute contained within RGS GM/RT2461 for maximum rate at which sand can be dispensed is based on a concern that sanding at higher rates may result in stationary or slow moving trains failing to operate track circuits because of excessive sand between the wheel and rail surface. However, there are circumstances under which sand can be applied at higher rates without compromising track circuit operation. There is no guidance on this subject available to TOCs, train owners or manufacturers.
- The TOCs' understanding of the characteristics of new rolling stock, which affected the way in which drivers were briefed about handling trains in low adhesion conditions and which was not optimal for the configuration of WSP and sanding equipment provided on modern trains.

17 Contributory to the performance experienced in autumn 2005 were:

- The absence of criteria within RGS on maximum braking distances under low adhesion conditions.

18 Several issues were identified that were neither causal nor contributory to the events of autumn 2005, but nonetheless need to be addressed in order to ensure that the issue of adhesion and train performance is addressed in an holistic manner:

- There is a need for further research into the mechanisms that create severe low adhesion conditions.

- There is no validated model available to test or optimise the performance of WSP systems that is capable of simulating the performance of the whole train or take into account the impact that key items of equipment such as sanding have on stopping performance.
- Further consideration needs to be given to establishing the optimum slip parameters for WSP systems under sustained low adhesion conditions. This does not mean that the current parameters are wrong but rather that they have still not been proven to be correct.
- In Britain, train braking is entirely dependent on available adhesion between wheel and rail. Magnetic brakes, currently used in some European countries, offer another means for slowing trains in emergencies.
- Investigation of low adhesion incidents is not performed in a consistent or systematic manner. If undertaken consistently in future, this will help to provide valuable data on the causes of such incidents.
- The data gathered by modern rolling stock represents a potentially valuable source of intelligence on adhesion conditions and could possibly be exploited to a greater degree than is currently the case.

Recommendations

19 Recommendations can be found in paragraph 283 and have been divided between those that can be implemented in the short term and those that can be implemented in the medium/long term. They relate to the following areas:

- measuring and understanding low adhesion conditions;
- methods for determining rail head treatment, including where and how to treat;
- short term and real time prediction of low adhesion conditions including the use of the capabilities of modern rolling stock to provide real time data on adhesion conditions;
- enhancements to RGS addressing braking and sanding parameters and configuration;
- configuration of WSP systems and the simulation of WSP performance;
- testing of alternative methods of stopping trains that do not solely rely on the wheel/rail interface;
- rolling stock sanding parameters and configuration;
- development of appropriate professional driving policies;
- investigation into adhesion-related incidents.

20 The RAIB sent eight short-term recommendations to relevant duty holders on 6 July 2006 in advance of formal consultation to enable relevant parties to consider them and to take action that they felt to be appropriate for autumn 2006.

The issue

Low adhesion incidents in autumn

21 Low adhesion is a level of adhesion between the wheel and the rail that has the potential to extend the braking distance beyond that required under normal conditions. Incidents caused by low adhesion occur most frequently during autumn. The phenomenon affects railway networks throughout the world. Low adhesion incidents comprise station overruns and SPADs, usually caused by the presence of contamination on the rail head which prevents the wheels from obtaining adequate adhesion during braking. Leaf residue is the most common contaminant.

22 The presence of contamination on the rail head can also cause loss of *train detection* when the contaminant acts as a barrier between the train wheels and the rail surface, preventing the wheels from operating the *track circuit*.

23 Although the number of adhesion-related incidents increases during autumn, there are significant variations year on year. Figure 2 shows the numbers of adhesion-related SPADs, adhesion-related station overruns and failures to operate track circuits for the six autumns from 2000 to 2005. In autumn 2005 there was a small increase in the number of SPADs and a significant increase in the number of station overruns in comparison with the previous year (see also Figure 1), while the number of failures to operate track circuits was similar. The number of SPADs and failures to operate track circuits was below the average for the preceding five years, but the number of station overruns was higher in 2005 than in any of the preceding five years.

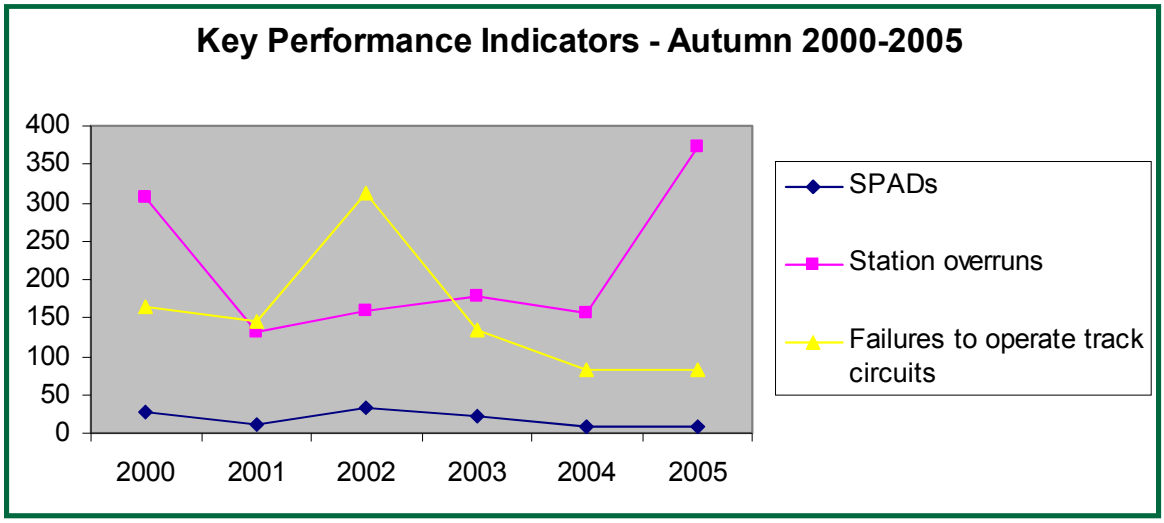


Figure 2: Adhesion-related incidents - autumn 2000 to autumn 2005.

24 This investigation has focused on adhesion-related station overrun and SPAD incidents. These incidents occur only in locations where trains are required to stop, in contrast with failures to operate track circuits which can occur anywhere on the network where contamination is severe enough to prevent electrical contact between wheel and rail. In view of the steady decline in incidents involving failures to operate track circuits, they have not been considered in this investigation. However, some of the measures employed to address the problem of railhead adhesion in the autumn have an effect on the issue of failure to operate track circuits. Sometimes the effect is beneficial; high pressure water

jetting cleans the surface of the rail and promotes conductivity between wheel and rail. The application of sand and *Sandite* (sometimes referred to as Electragel) if not properly controlled, can act as a barrier between wheel and rail which is sufficient to prevent the conductivity necessary for track circuit operation. Sandite now comprises steel particles and sand suspended in a gel, with the metal being included to improve track circuit operation. Service trains only dispense sand.

The parties involved

25 The parties directly affected by low adhesion are Network Rail and the TOCs.

Location of adhesion-related problems

26 Although adhesion-related problems can occur virtually anywhere on the network, there are some locations that are more vulnerable than others (paragraph 70 and Figures 7a and 7b). Table A in the s*ectional appendices* provides information on specific sites where exceptional rail head conditions may be encountered. The TOCs produce detailed briefing notes for drivers that include information on areas where low adhesion may occur. Although these notes draw upon the information provided in the sectional appendices, they may include additional sites that the TOC wishes to highlight to its drivers. Falmer bank, the site of the adhesion problems that caused the SPAD at Lewes on 30 November 2005, is an example of a location that is not included as a low adhesion site in the relevant sectional appendix but is highlighted to drivers as such in the briefing note for the route.

27 Esher, the location of an adhesion-related SPAD on 25 November 2005, had not been identified as a low adhesion location. The fast line between Woking and Surbiton was not treated to counter the effects of low adhesion because, prior to autumn 2005, there had been no experience of low adhesion incidents in that area.

Factors that can affect adhesion

28 The presence of contaminant on the rail surface is one of the key causes of adhesion problems. The most common source of contamination is leaf-fall onto the line and the subsequent crushing of leaves into a soft or hard 'teflon'-like residue.

29 The AWG has prepared a low adhesion manual[2], which lists the following causes of low adhesion:

- general moisture/dampness, particularly in cuttings, mixed with contaminants such as railhead rust or leaf residue;
- light rain/drizzle after a dry period mixed with contaminants such as rail head rust or leaf residue;
- ice on the rail;
- dust, particularly coal dust;
- spilled diesel fuel and lubricating oils from locomotives and *diesel multiple units*;

[2] *Adhesion Working Group, 'Managinh Low Adhesion', Third Edition, September 2004.*

- leaking hydraulic fluid from track machines;
- defective rail mounted flange lubricators (dispensing excessive amounts of grease);
- airborne kerosene near airports and chemicals near industrial sites.

30 Not all of the items on the list are associated with the autumn period alone and not all of them are within the control of the railway. Leaf-fall is not the only factor that influences the level of adhesion available. Research undertaken by the University of Sheffield[3] highlights water as being the most important cause of low adhesion and particularly when small amounts of water are present (heavy rain will clean the rail). Water on clean rail does not create adhesion problems for trains in braking but a small amount of water in combination with contamination does.

31 Some of the factors that cause low adhesion are localised and transient in nature. This makes it difficult to predict exactly when conditions will deteriorate to the point where adhesion-related incidents may occur. Changes in humidity can result in damp rail surfaces for a relatively short period of time; once the surface of the rail dries the contamination alone may not cause adhesion difficulties for trains. The likelihood of an adhesion-related incident occurring during this time is also affected by whether the rail head has been treated recently and by the requirement for trains to stop in a location where low adhesion conditions are present. The incident at Lewes (described in part 2 of this investigation report) provides a good illustration of the critical part that dampness plays in creating or exacerbating low adhesion conditions.

32 Although there is extensive knowledge regarding the causes of low adhesion, there remains some uncertainty over the mechanisms that create severe low adhesion conditions. The incident at Esher reported as Part 1 of this investigation resulted in an overrun of approximately 1050 metres, yet no contamination was visible to the naked eye and none was found on swabs taken from the rail head. This does not mean that contamination was not present, but rather that detection of the causes of contamination is sometimes problematic.

Management of low adhesion

Infrastructure Manager

33 Low adhesion is managed through an extensive set of measures implemented by Network Rail and the TOCs. The requirements are laid down in RGS GE/RT8040. This RGS obliges the Infrastructure Manager (i.e. Network Rail for the main line rail network) to control the risk of low adhesion to a level that is as low as reasonably practicable, by:

- having processes in place to identify locations where low adhesion might occur;
- publishing details of low adhesion locations in the Sectional Appendices;
- leading development of site-specific plans to reduce the likelihood of low adhesion occurring;
- leading development of action plans to manage low adhesion at new sites;
- monitoring the performance and reviewing plans to ensure effective action is taken.

[3] New Rail Materials and Coatings, Report for the Rail Safety & Standards Board, REF. RRUK/A2/1,University of Sheffield, July 2003

34 Network Rail implements the requirements of the RGS with its own *Company Procedure*, NR/SP/OPS/096[4]. The procedure sets out the steps taken by Network Rail to identify high-risk adhesion sites comprising a risk assessment approach or review of historical records. Feedback from traincrew or infrastructure maintenance staff, analysis of *on train monitoring and recording* (OTMR) equipment, commissioned research, analysis of data recorders and local knowledge can be used as input. Using the historical records approach, sites will only be published in the sectional appendix if there have been more than 2 SPADs or more than 4 overruns in the last three years as a result of leaf-fall.

35 Network Rail has various ways of controlling the risk at low adhesion sites. Vegetation management is employed to eliminate the sources of leaf-fall. This technique, which involves cutting back or cutting down trees and bushes, is only under Network Rail's control for vegetation growing on the railway side of the boundary fence. Landowners of property adjacent to the railway are often unwilling to lose the screen provided by trees and bushes, in which case the leaf-fall will continue to affect railway infrastructure.

36 Network Rail seeks to eliminate low adhesion conditions during the leaf-fall season by treating the rail surface. *Multi Purpose Vehicles (MPVs)* and Rail Head Treatment Trains clean the rail head using high pressure water jets. In some parts of the network during 2005, the MPVs also applied Sandite to the rail surface to enhance adhesion. At known problem sites, static Traction Gel applicators are employed, which are triggered by passing trains and use the train wheels to apply a small amount of Sandite over the affected section of line.

37 On a tactical level, Network Rail used the specialist environmental and weather organisation, ADAS UK Ltd, to predict leaf-fall patterns in 16 geographical areas on a daily basis during autumn 2005. When severe conditions are predicted, additional measures are employed to improve wheel/rail adhesion in known problem areas. Those measures include increasing the number and/or extent of treatment programmes using high-pressure water jets and Sandite, the use of Sandite in areas where water jetting alone is normally used and the provision of 'rapid response' gangs to deal immediately with adhesion problems as they occur, using rail surface scrubbers and manually applying sand. As the treatment of the rail head in this way involves Network Rail staff going onto the 'live' railway where they are exposed to the hazards of train movement, the activity is subject to rigorous risk assessment. Network Rail also strengthens its Route Control arrangements during the autumn period with the use of an individual designated as adhesion controller whose responsibility is to monitor adhesion conditions, deal with low adhesion reports and take action to ensure that low adhesion conditions are dealt with expeditiously.

38 Network Rail liaises with TOCs over the plan for rail head treatment and there is a process in place that promotes feedback on adhesion issues from TOCs to Network Rail. As described in paragraph 34, Network Rail has a process in place for determining whether information on low adhesion sites provided by the TOCs justifies their inclusion within the relevant sectional appendix.

[4] *Network Rail, NS/SP/OPS/096 'Determining High Risk Sites for Low Rail Adhesion (formerly RT/D/P/096), Issue 1, Network Rail, August 2004.*

Train Operating Companies

39 RGS GE/RT 8040 obliges TOCs to:

- cooperate with the Infrastructure Manager to reduce the risk arising from low adhesion;
- ensure drivers are trained and competent to recognise those locations where low adhesion may occur and to use appropriate driving techniques when low adhesion conditions are encountered;
- consider the provision of train borne systems to improve braking performance under conditions of low adhesion including optimised WSP and sanding equipment;
- consider using on-train systems to detect wheelslide activity and alert the driver;
- consider providing remote monitoring systems to alert drivers to low adhesion conditions.

40 TOCs liaise with Network Rail in order to provide input to each autumn's plans for rail head treatment. There is also a critical process of real time feedback during periods of low adhesion when train drivers advise signallers about problems they have encountered, which can then result in warnings being issued to drivers to approach the area with caution and additional railhead treatment in the problem area.

41 TOCs employ a range of measures to ensure their drivers are competent to deal with low adhesion conditions. Training methods include the use of 'skid pan' training and simulators.

42 In addition to training, TOCs brief drivers on driving techniques for low adhesion conditions prior to the start of the leaf-fall season. In autumn 2005, the briefing generally emphasised the need for 'light and early' braking, although there was some variation in the techniques adopted by different TOCs for managing low adhesion.

43 One of the principal contributions made by TOCs to managing low adhesion is to operate rolling stock equipped with systems designed to cope with low adhesion such as WSP and sanding. In autumn 2005, approximately 90% of rolling stock operating over the national railway network was equipped with a WSP system. The availability of WSP (and sanding – see paragraph 45) has resulted in less reliance on driver action to control wheelslides, the emphasis being on allowing the WSP system and sanding to manage train braking in low adhesion conditions.

44 The WSP system works by detecting wheelslide and regulating the rotational speed of the wheels by means of the controlled release and re-application of the brakes. This control mechanism limits the extent of slip to around 17-20% (i.e. the difference between the actual rotational speed of the wheels and the rotational speed they would have achieved had they not been sliding is not permitted to exceed 20%).

45 Trainborne sanding equipment complements the WSP system. The application of sand is beneficial for adhesion in both traction and braking. Sanding equipment has been available on multiple units since the mid 1990s and more than 80% of multiple units operating over the national railway network are equipped with sanders. Sanding systems have evolved and different systems are currently in use. The original equipment was activated by the driver and consisted of a single application for a limited duration ('one-shot' sanders). The majority of modern multiple units are equipped with automatic sanding when WSP activity occurs during braking and manual sanding under the control of the driver when wheel slip is encountered in traction. The point at which automatic sanding commences varies between different types of multiple unit and is dependent on the *brake step* selected

by the driver. Other measures are adopted by TOCs selectively to address low adhesion conditions. Some TOCs adopt an autumn timetable on routes that are particularly susceptible to low adhesion conditions, e.g. Southern on the East Grinstead line. Some TOCs also operate longer trains during the autumn. While this is not possible during peak hours because maximum demand for stock is present at this time, trains can sometimes be strengthened off peak. The relevance of operating longer trains to coping with low adhesion conditions is explained in paragraph 66.

Characteristics of low adhesion incidents

46 Parts 1 and 2 of this report provide details of two adhesion related SPAD incidents that occurred at Esher on 25 November 2005 and Lewes on 30 November 2005. Figure 3 contains details of eight station overruns and one other SPAD that occurred during autumn 2005.

Details
Train 2L69 (class 450 EMU) approached Farnborough station at approximately 70 mph (112 km/h). Driver selected step 1 brake in accordance with 'light and early' philosophy. WSP became active immediately and train speed fell only slowly. After 15 seconds the driver selected step 2 braking and then steps 3 and emergency in rapid succession, but the train overshot the station by 400m.
Train 2N80 (class 450 EMU) approached Wanborough station at 15 mph (24 km/h), the driver having completed a light and early brake application to bring the train speed down for stopping. Driver selected step 1 brake for final stop and WSP became active immediately. Step 2, step 3 and emergency brakes were used in the space of 30 seconds but the train overshot the station by 20m.
Train 2N50 (class 377 EMU) approached Emsworth station at approximately 50 mph (80km/h) and the driver made a light and early step 1 brake application. WSP successively activated on the three vehicles on the train. The driver selected steps 2, 3 and emergency braking over the space of 15 seconds but train overshot station by 80m. Train had taken approximately 1000m and 57 seconds to stop.
Train 1E69 (class 377 EMU) approached Horley station at approximately 70 mph (112 km/h). The driver made a step 1 brake application earlier than normal because of wet and windy conditions. Within four seconds, WSP activity commenced on all four vehicles. The driver selected step 2 braking and then within 10 seconds had moved straight to emergency braking, but train overshot station by approximately 80m. Train had taken approximately 1500m and 70 seconds to stop.
Train 2C78 (class 377 EMU) approached Earlswood station at approximately 45 mph (73km/h). The driver selected step 1 braking earlier than usual because of the wet and windy conditions. All four vehicles experienced WSP activity. The driver released and reapplied the brake and WSP activity recommenced. Steps 2 and 3 braking were selected in rapid succession, but the train overshot the station by approximately 40m.
Train 1R73 (class 375 EMU) approached Deal station and the driver applied step 1 brake early because of drizzly conditions. With train speed at 37 mph (58 km/h) WSP activity commenced on all three vehicles. The driver selected brake steps 2, 3 and emergency but the train not only overshot Deal station but also passed signal EBZ40 at danger by 60m. The train had taken 680m to stop from the time that WSP had become active.
Train 2J75 (class 375 EMU) approached Nutfield station at approximately 50 mph (80 km/h. Driver applied step 1 brake approximately 800m from the station. WSP activity occurred on all vehicles immediately and the driver rapidly moved into brake step 3 and then emergency shortly after. The train overshot the station by approximately 1200 metres, having taken 2000 metres and 135 seconds to stop. (This equates to an average braking rate of $0.18m/s^2$).
Train 2U12 (class 465 EMU) approached Bexleyheath station at approximately 45 mph (73 km/h). Driver applied step 1 brake in accordance with the light and early philosophy. WSP activity commenced on all vehicles immediately and the driver moved rapidly through the brake steps to emergency but deceleration remained extremely limited. The train overran the station by approximately 1000 metres.
Train 2A07 (class 377 EMU) approached Stoats Nest Junction (near Coulsdon) at approximately 70 mph (112 km/h) and the driver made an early step 1 brake application to stop at Purley station because of slippery conditions. WSP became active immediately. Over the next 20 seconds the driver moved through the brake steps to emergency brake, but speed only reduced to 63 mph (101km/h) by Purley station. Shortly after running through Purley station, the train brakes started to work effectively and the train stopped 440 metres beyond Purley station platform. Minimal rail head contamination was found.

Figure 3: Case studies of adhesion-related incidents in autumn 2005.

47 The incidents described in Figure 3 indicate that the following features were associated with severe low adhesion incidents in autumn 2005:

- On initial application of the brake in step 1, there is no discernible reduction in speed. Depending on the characteristics of the rolling stock, there may also be an indication of WSP activity through the illumination of the desk light or significant fluctuations in speed registered on the speedometer. Where WSP is fitted, the driver may hear the sound of the *blowdown valves* operating as air is released from the braking system.
- When drivers increase the brake to step 2, there may be only limited effect on train speed. If fitted, WSP continues to operate and automatic sanding may commence, but the braking rate of the train is below the driver's expectations.
- Increasing the brake to step 3 and emergency results in some reduction in speed, but at a lower rate than would be expected. By this stage, the driver will have realised that the train is not going to achieve its targeted stopping point, whether that is a station or signal, or that it is not going to achieve a targeted speed reduction for a permanent or temporary speed restriction. In the case of an impending SPAD incident, the driver may now make an emergency call to the signaller.
- Eventually, the train stops, by this stage beyond the targeted stopping point. The way in which the train stops varies and this is likely to be dependent on the length of track over which low adhesion conditions are present. A sudden stop will result from the train encountering rail that is not contaminated.

Response to low adhesion incidents

48 The response to low adhesion incidents is dependent on the seriousness of the incident:

- If a driver has experienced difficulty in stopping, RGS GE/RT8000 (the *Rule Book)* requires that he or she must alert the signaller if the area is not one of those listed in the sectional appendix (paragraph 34). If the location is listed in the sectional appendix and railhead conditions are exceptionally poor the driver must also alert the signaller.
- The Rule Book mandates a range of actions to be taken by the signaller on advice from a driver of low adhesion conditions. The action is dependent on the location of the problem:

Location where conditions apply	Action to be taken
Approach to a stop signal	Arrange for the driver of each approaching train to be told of the circumstances unless showing a proceed aspect
Manned level crossing within the overlap of the signal	Close the crossing to road traffic **before** each train approaches
AHBC level crossing	Select the non-stopping mode (where provided)
Approach to a platform	Arrange for the driver of each train booked to call to be told about the circumstances
Dead-end platform	Arrange, if possible, for the platform to be taken out of use

- Network Rail's route controller will arrange for the relevant section of line to be inspected as soon as a *Mobile Operations Manager* (MOM) can be deployed to site. If necessary, the rail head will be subject to additional treatment (local application of sand or Sandite, scrubbing of rail surface). If no contamination is found, the driver of the next train to pass through the area will be asked to undertake a controlled stop in order to prove that stopping conditions are normal. If they are not, further sanding and scrubbing takes place until normal stopping conditions are established.
- The requirement to restore railway operations as quickly as possible after an incident means that there is limited time available for a comprehensive determination of cause. Because of this, wheel swabbing is rarely carried out and determination of the presence or otherwise of contamination on the rail head is limited to a visual inspection by the MOM. Only if the MOM sees contamination will swabs be taken. In 45% of the adhesion related incidents occurring in autumn 2005, no rail head contamination was observed by the MOM. Among the incidents where no contamination was seen were two where the length of overrun exceeded 1,000 metres.
- Swabs are sent to Scientifics Ltd for analysis. They have the capability to perform microscopy, x-ray fluorescence, gas chromatography and mass spectrometry tests in order to identify evidence of vegetation, silicon, hydrocarbons, and the specific detail of other organic contamination. This may help to prove the presence or otherwise of the designated contaminant although there is no way of using the results to determine the actual level of adhesion that was available on the day.
- For low adhesion events that result in accidents or involve signals being passed at danger, Network Rail and the relevant TOC conduct an investigation in accordance with the requirements of RGS GO/RT3252 (Signals Passed at Danger). Investigations have been conducted into the incidents at Esher and Lewes.

The Investigation

Investigation process

49 The starting point for the investigation was the initial findings into the low adhesion SPAD incidents at Esher on 25 November 2005 and Lewes on 30 November 2005. The purpose of Part 3 of the investigation was to establish the reasons why the number of low adhesion incidents during autumn 2005 was much higher than in the preceding year with a view to making recommendations that would help to minimise the number of adhesion-related incidents that occur in future.

50 The key elements to the investigation comprised the following workstreams:

- Data analysis of low-adhesion incidents for the years 2000, 2004 and 2005. The purpose of the analysis was to understand the characteristics and circumstances of each incident occurring in these three years. The year 2000 was chosen because it was the worst year for adhesion-related incidents in the five years before 2005. The year 2004 was chosen because it was the best year for adhesion-related incidents in the five years before 2005. In addition, the TOCs that operate services in Kent, Surrey, Sussex and Hampshire were running their new and old fleets alongside each other in 2004; the only year when direct comparisons between the performance of new and old fleets could be made.
- Analysis of infrastructure issues, targeted at understanding the causes of low adhesion, the steps taken by the Infrastructure Manager to mitigate the risk and relevant research findings.
- Analysis of rolling stock issues, targeted at understanding the range of systems relevant to low adhesion management such as WSP, sanding and braking, the standards governing performance of those systems and the processes in place for testing WSP systems. This workstream also examined research in this area.
- Analysis of operations issues, targeted at the link between the characteristics of rolling stock and the advice given to drivers on how trains should be handled in low adhesion conditions. This workstream also examined the processes applied to procuring and approving new rolling stock.

51 Throughout the course of the investigation, the inter-relationship between infrastructure, rolling stock and operations has been a constant theme and the division of the investigation into separate areas has not precluded consideration of system and interface issues.

Sources of evidence

52 The data review for 2000, 2004 and 2005 was based on the daily incident logs prepared by Network Rail's National Control Centre, supplemented by information from the RSSB's *Safety Management Information System* (SMIS).

53 Meetings have been held with Network Rail at headquarters and route level to discuss railhead treatment policy and practice. The information obtained has been supplemented with data provided by the AWG. The RAIB has exchanged information with the AWG and met with their representatives to review progress and share thinking. The RAIB has also reviewed the report prepared by AWG into the events of autumn 2005.

54 Meetings have been held to examine the specification, characteristics and performance of modern rolling stock with TOCs (SWT, Southern, South Eastern Trains, c2c, Merseyrail and First ScotRail), the rolling stock manufacturers (Bombardier and Siemens) and a manufacturer of braking, sanding and WSP systems (Knorr Bremse). Meetings have also been held with AEA Technology to discuss the operation of the simulator they use to test the performance of WSP systems, and with Interfleet, to discuss the rolling stock approvals process.

55 Information on training and briefing to drivers has been supplied by the TOCs identified above and South Eastern Trains and First Group (jointly with Network Rail) provided their own assessments of performance during autumn 2005[5].

56 Network Rail and the TOCs have provided information on practices followed in the aftermath of low adhesion incidents.

57 RSSB has provided information on ongoing research into various aspects of low adhesion management and on RGS and *Technical Specifications for Interoperability (TSI)*.

Key evidence

58 Key items of evidence are:

- data on autumn low adhesion incidents for 2000, 2004 and 2005;
- the OTMR downloads from trains involved in low adhesion incidents;
- documentation supplied by SWT and Southern on the specification, design, manufacture and testing of their new-build rolling stock and on their briefing of drivers on techniques for handling low adhesion incidents;
- the methodology and pass criteria applied to the testing of WSP systems on the *WSPER*® ;
- the report issued by the AWG into the events of last autumn.

[5] Adhesion Working Group, 'Report of an independent review of low adhesion incident performance during autumn 2005', April 2006

Analysis

Review of data

Introduction

59 This section:

- provides some basic data regarding adhesion-related incidents, including analysis of the distribution of events:
  - throughout the autumn period;
  - by overrun distance;
  - by length of train;
  - by time of day;
  - by geography.
- analyses the distribution of adhesion-related events by rolling stock fleets;
- assesses whether modern rolling stock fleets are more susceptible to adhesion-related events than the stock that they replaced.

Data on adhesion-related incidents

60 Figure 4 shows the distribution of adhesion-related SPADs and station overruns from 1 October to 31 December for the years 2000, 2004 and 2005 (see paragraph 50 for an explanation of why these three years were chosen).

61 The data sources were identical for each of the three years (paragraph 52) and reporting procedures for adhesion-related incidents have not changed significantly since 2000. Both of these factors provide a degree of assurance on the dependability of the data.

62 The pattern of events is clearly different between the three years:

- 2000 had one pronounced peak and relatively few days with no incidents from the beginning of November;
- 2004 had one pronounced peak and a very low level of occurrence from the beginning of November;
- 2005 had three pronounced peaks. It was the most erratic of the three autumns; days with no events were scattered at frequent intervals as were days with a high number of events.

63 Figure 4 shows that each of the three autumns produced a different occurrence profile. The industry cannot rely on past experience to guide it on such matters as the timing or extent of peaks.

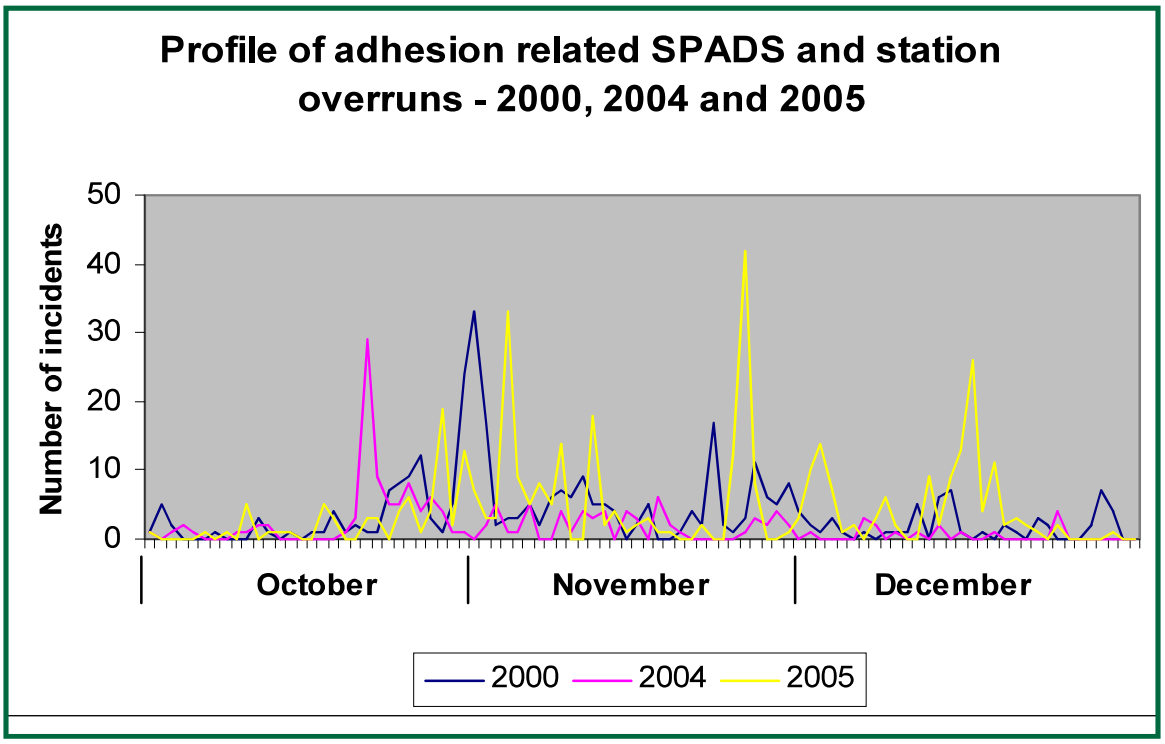


Figure 4; Profile of adhesion-related incidents - autumn 2000, 2004 and 2005.

Length of overruns

64 In autumn 2005, the extent of the overruns varied from 1 metre to 2000 metres. The graph presented in Figure 5 shows the range and distribution. The equivalent data for 2000 and 2004 have been included and show that the distribution of incidents is broadly similar for the three years. For station overruns, the figures may slightly underestimate the extent of the overrun because the measurement is taken from the end of the platform. In some cases, the driver's targeted stopping point will have been an intermediate point along the platform rather than the end.

65 Incidents labelled 'Fail to Call' in Figure 5 relate to those where the driver has decided to continue to the next station rather than return to the station that has just been overshot.

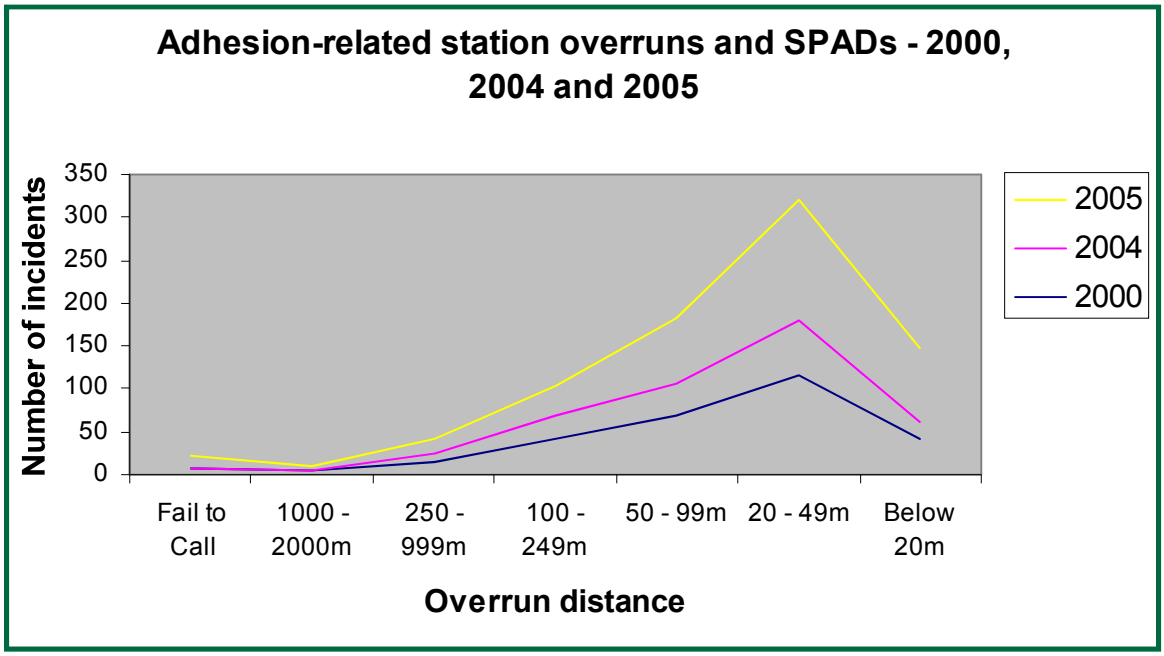


Figure 5: Distribution of length of overrun, 2000, 2004 and 2005.

Length of trains involved in overruns

66 In autumn 2005, detail on train formation was available for 375 adhesion-related incidents (368 station overruns and 7 SPADs). Of these 375 incidents, 325 (87%) involved trains of five vehicles or less. In 2004, the figure was 83%. Ideally, these figures would be considered in the context of the percentage of trains that are operated in formations of five vehicles or less, but this figure is not readily available. In talking with drivers and their managers, the view has been expressed that shorter trains can take longer to stop in low adhesion conditions and this is a generally (if not universally) held belief within the industry. One of the functions of WSP systems is to *condition* the rail head (paragraph 141), which improves adhesion for following wheels. A review of on-train data for the Esher and Lewes incidents showed that better braking performance was achieved at the rear of each train involved. There is thus evidence that the longer the train, the greater will be the benefit from *conditioning*.

Time of day when overruns occur

67 Figure 6 shows the distribution throughout the day of adhesion-related incidents for 2000, 2004 and 2005. Years 2000 and 2005 show a similar occurrence profile between 00:01 hrs and 20:00 hrs. The 2004 occurrence profile is similar to the other two years until 16:00, after which there is a notable decline in occurrences, not matched by experience in 2000 and 2005.

68 The relatively low level of occurrence between 00:01 hrs and 06:00 hrs is proportionate to the amount of rail traffic that is operating at the time. The morning peak period sees the highest number of adhesion-related incidents in all three years, but occurrence levels in the evening peak hours are not noticeably higher than those in off-peak periods. In 2005, the numbers of incidents occurring between 21:01 hrs and 22:00 hrs was higher than in any of the evening peak hours, despite there being fewer trains operating at this time of day. However, longer trains operate in the peaks, which may help to reduce the probability of an overrun occurring.

69 Damp rail head conditions can occur at any time of day, but changes in humidity can often occur in the period around dawn creating the damp conditions that can exacerbate the effects of contaminants present. There is often a sparse train service overnight (if any at all) and this means that contamination is not being disturbed or removed by passing trains in the period before dawn. These factors may help to explain why the highest rate of occurrence of adhesion-related incidents is in the morning peak period, although the detrimental effects should be offset by rail head treatment which takes place in the early hours of the morning as well as from mid-morning to early afternoon. It is possible that the lower levels of occurrence around the middle of the day and early afternoon reflect the beneficial effects of the second treatment. This might also explain why the numbers of incidents do not fall significantly in the late evening, as the effects of the second treatment have worn off by this time.

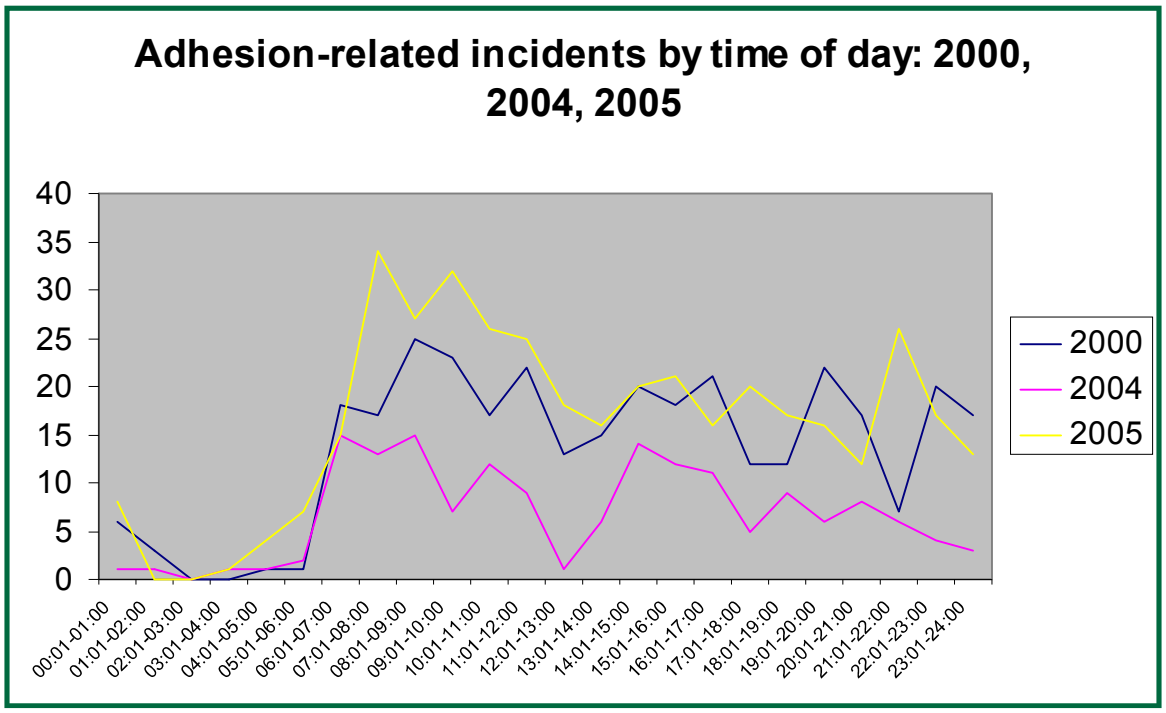


Figure 6: Distribution of adhesion-related incidents by time of day, 2000, 2004 and 2005.

Location of overruns

70 Figures 7a and 7b shows how the adhesion-related incidents that occurred in 2004 and 2005 were distributed throughout the country. It is evident from the maps that there was a polarisation towards the south east and Scotland in 2005 as well as consistent clustering of incidents in the north west. It is also apparent that some parts of the network experienced negligible numbers of incidents or none at all, confirming that low adhesion conditions are not entirely random events and that certain factors do make specific locations vulnerable to SPADs and station overruns during the autumn period. While there is some correlation between numbers of incidents and intensity of train service, the relatively low level of incidents in the Midlands indicates that this is not the governing factor.

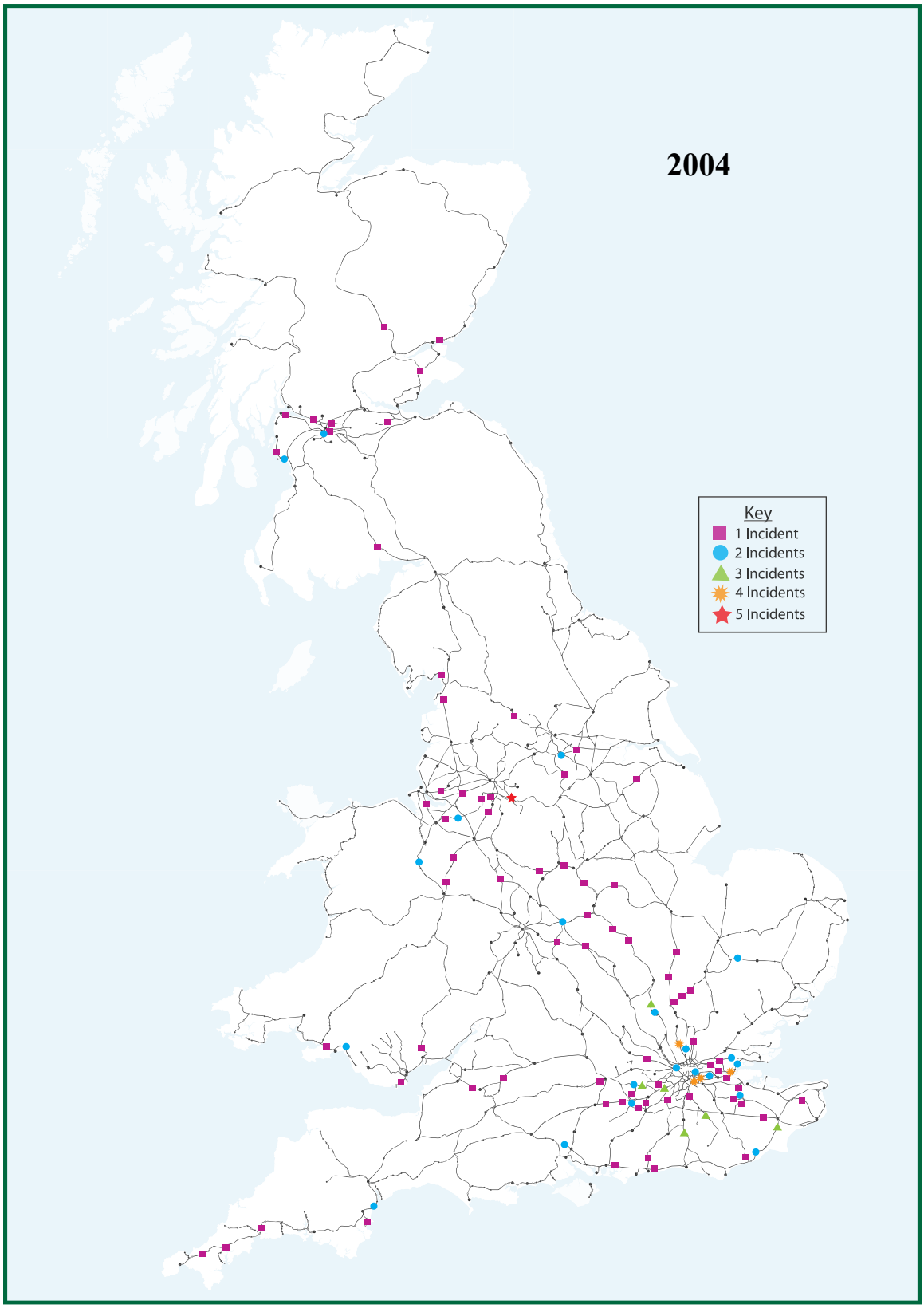


Figure 7a: Distribution of adhesion-related incidents - 2004.

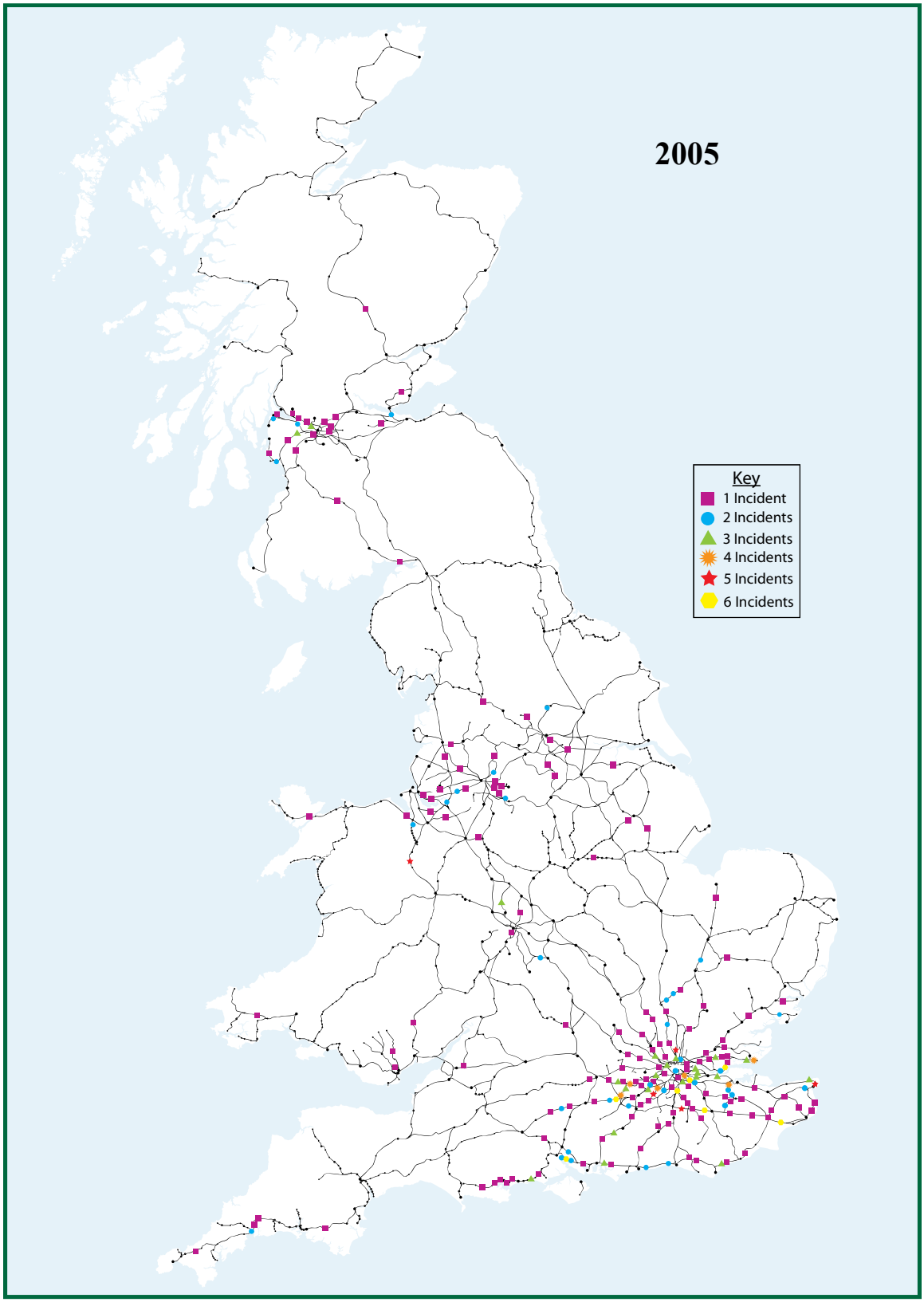


Figure 7b: Distribution of adhesion-related incidents - 2005.

Rolling stock characteristics

71 The performance of each of the fleets of rolling stock during autumn 2005 has been examined to try to establish whether there are any common characteristics that they share that might help to explain the reasons why some fleets were more likely to be involved in adhesion-related incidents than others. Performance between different fleets is not comparable without normalising the data to take account of fleet size or fleet operation. Figure 8 contains two columns, the first ranks the fleets according to the number of low adhesion incidents experienced when normalised by fleet size (no. of incidents/number of units in fleet). The second column ranks the fleets according to the number of low adhesion events experienced when normalised by activity (no. of incidents/annual mileage). The latter analysis was undertaken by Network Rail and First Group. The fleet ranked '1' is that which experienced the highest number of adhesion incidents.

Rank	Normalised by total number of units in fleet	Normalised by annual mileage
1	314*	458*
2	450	314*
3	508+	508+
4	334	320*
5	357+	450
6	375	334
7	444	357+
8	458*	313*
9	320*	375
10	365*	142^

Key
^Fleets equipped with neither sanders nor WSP
**Fleets not equipped with sanders*
+Fleets partially equipped with sanders (for autumn 2005, majority of Class 508 was equipped, majority of Class 357 was not equipped)

Figure 8: Highest occurence of adhesion-related incidents - normalised by fleet size and by annual mileage.

72 *Electric Multiple Units* (EMU) classes account for the top ten places when expressed on an 'incident per fleet size' basis and nine of the top ten places when expressed on an 'incident per miles operated' basis. Eight of the classes appear in the top ten whether normalised by fleet size or mileage. Classes 365 and 444 appear within the top ten only when normalised by fleet size. Classes 142 and 313 appear within the top ten only when normalised by mileage operated. The Class 142 is the only diesel multiple unit (DMU) that appears on either list.

73 There is no single reason that explains the presence of the fleets that occupy the top ten places, but there are reasons why individual classes appear in the top ten and these are explained below.

74 The Class 314 is ranked at or nearly at the top of both lists. The fleet, comprising 16 units, operates local services around Glasgow with frequent station stops. Although fitted with a WSP system, the Class 314 is not equipped with sanders.

75 The Class 458, which appears either 8th or 1st depending on how performance is ranked, is operated almost exclusively over the Waterloo to Reading route which is characterised by frequent station stops. Every adhesion related incident occurred between Virginia Water and Earley, in the more rural section of the route. During autumn 2005, the Class 458 was fitted with a WSP system but not equipped with sanders.

76 The performance of the Class 508 which appears third on each list was variable. Three TOCs operated the Class 508 (and the similar Class 507) during autumn 2005, Merseyrail, Silverlink and South Eastern Trains. The Class 508 units operated by Merseyrail and South Eastern Trains were equipped with a WSP system and sanding, while the Class 508 fleet operated by Silverlink was equipped with a WSP system only.

77 Merseyrail, the dominant operator of the Class 508, experienced no adhesion-related incidents in autumn 2005, while Silverlink experienced a single incident. Fifteen incidents were attributable to South Eastern Trains's fleet of 12 units.

78 South Eastern Trains conducted its own analysis into performance during autumn 2005 and has concluded that the reasons for the poor performance of the Class 508 were:

- The Class 508 fleet operated predominantly in single unit (three car) formations.
- The vehicles were the lightest of South Eastern Trains's fleet.
- It had a 'one-shot' sanding system, which limited the amount of sand that is available to a driver during prolonged slides.
- The WSP system was a 'first generation' device, lacking the sophistication of the systems fitted to units delivered recently. See paragraph 144 for a description of the characteristics of older WSP systems.
- The Class 508 fleet operates over two routes that have traditionally suffered a high number of overrun incidents during low adhesion conditions (Medway Valley and Tonbridge to Redhill). The former route follows the river Medway, which raises the moisture level and it also runs through areas of lush vegetation. The latter route is straight and level but exposed to the elements.

79 The analysis performed by South Eastern Trains demonstrates the need to treat the information in Figure 8 with caution. There are a range of variables that might explain different levels of performance. The most obvious is stopping pattern; the greater the number of station stops, the greater the exposure to a possible overrun. EMUs operate the majority of services around the major cities that stop frequently and would therefore be more exposed to the hazard of overrunning stations. However, suburban routes around cities have relatively low levels of vegetation alongside the line in comparison with rural areas. The fleets that perform much of this suburban work to the south and south east of London (Classes 455, 456, 465 and 466) do not appear in either top ten.

80 One specific issue that the RAIB's investigation sought to address was whether 'modern' trains are more susceptible to adhesion-related incidents than older trains. In attempting to undertake such an analysis, the principal difficulty was in defining what was meant by 'modern' and 'older'. Some modern trains were not equipped with sanders during autumn 2005 (e.g. Classes 357/0 and 458) while some older trains were (e.g. Classes 159 and 323). Age alone is not a basis for comparison when some older units have been retrospectively equipped with modern systems for dealing with low adhesion conditions.

81 However, the opportunity to compare modern and older trains was available in the South East of England where four operators had modernised their fleets in a relatively short period of time. It was therefore possible to compare adhesion performance in the years 2000, 2004 and 2005 to establish whether there were significant differences that might help to establish whether modern rolling stock was more susceptible to adhesion-related incidents.

82 The fleets considered were those that operate the 'main line' services of SWT, Southern Railway (formerly Connex South Central) and South Eastern Trains (formerly Connex South Eastern) and those operating all services of c2c. See Figure 9

Operator	2000 Fleet	2005 Fleet
South West Trains	Class 411, 412, 421, 423	Class 444, 450, 458
Southern (Connex)	Class 411, 421, 423	Class 377
South Eastern Trains (Connex)	Class 411, 421, 423	Class 375*
c2c	Class 310, 312	Class 357

Figure 9: Classes comprising main line fleets of South West Trains, Southern Railway, South Eastern Trains and c2c in 2000 and 2005.

83 Figure 10 shows the number of adhesion-related incidents involving relevant fleets in 2000 and 2005. Although it would have been possible to normalise the figures by the number of units in each fleet, this would have biased good performance towards the 2000 fleet because of the high levels of utilisation achieved with modern rolling stock. Given that the geographical boundaries for the four operators have not changed in the intervening period, the figures simply represent the number of incidents occurring within their operating area for the two years involving the designated rolling stock.

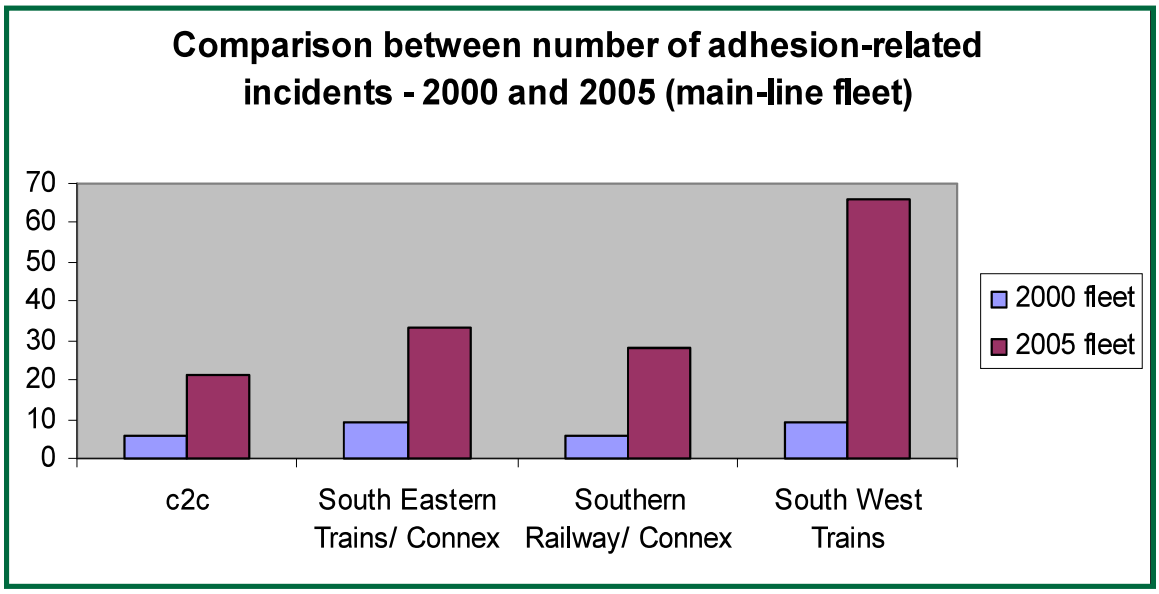


Figure 10: Numbers of adhesion-related incidents affecting main line fleets of four TOCs, 2000 and 2005.

84 A possible explanation of the differences between the two years might be that weather and environmental conditions in the two autumns were not comparable. In order to determine whether this might be the case, a comparison was made between the numbers of adhesion-related incidents in 2000 and 2005 involving the suburban fleets used by South Eastern Trains, Southern Railway and SWT, which did not change significantly in that period. Figure 11 shows that for two of the three operators, there was an improvement in performance between 2000 and 2005, whereas for the third, although there was a deterioration in performance (31% worse), it was not as marked as that experienced by the main line fleet (267% worse). This suggests that any difference in weather and environmental conditions between the two years was not necessarily relevant to performance.

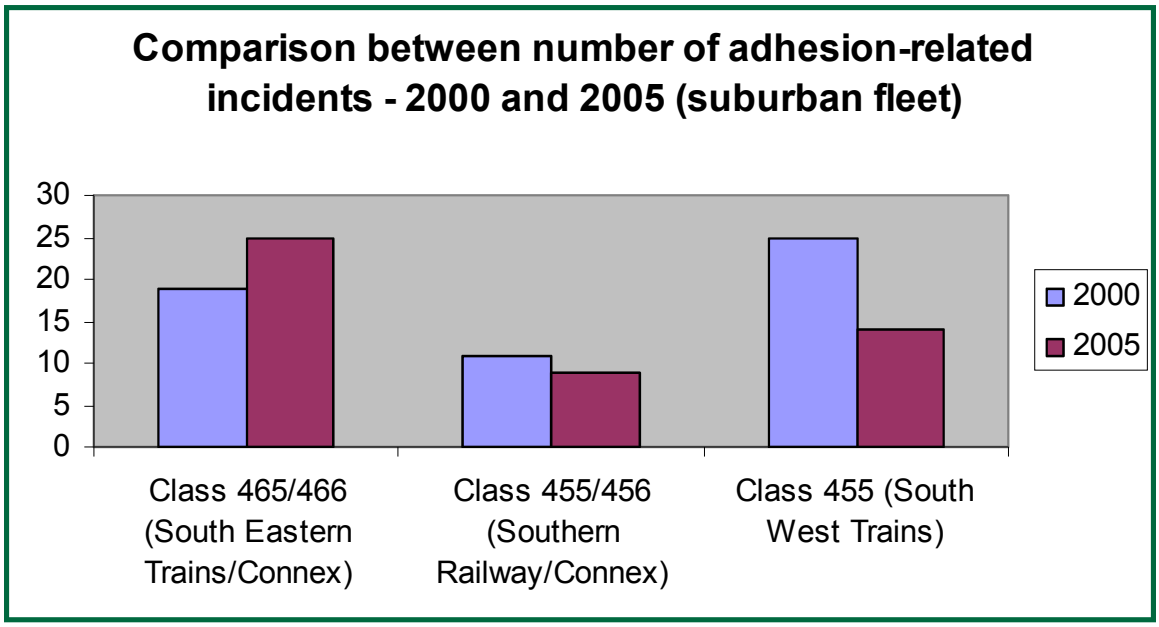
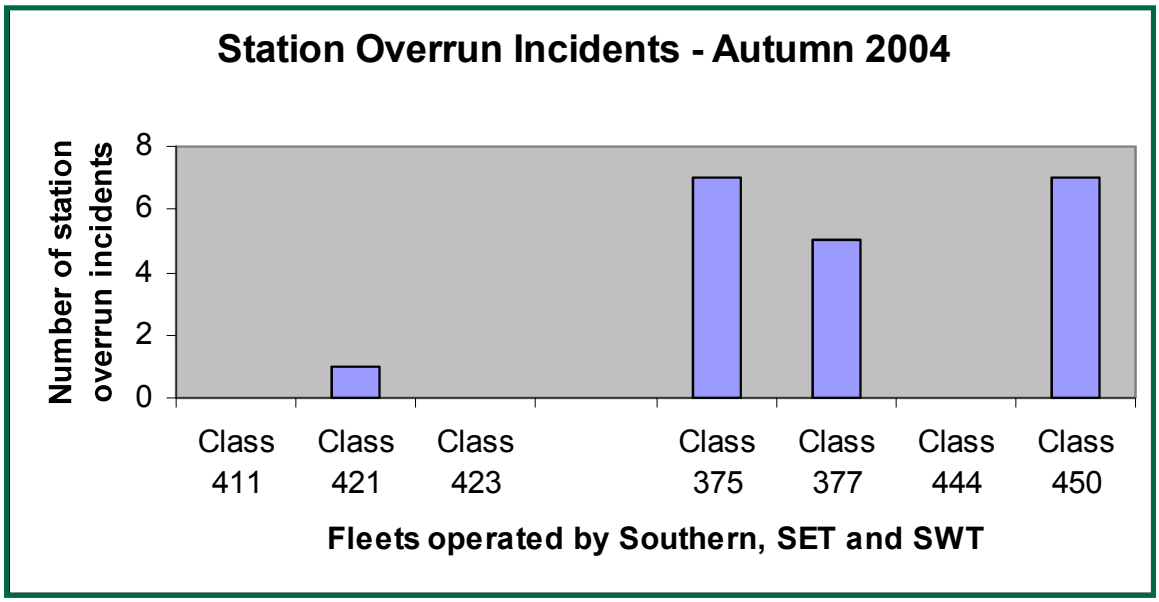


Figure 11: Numbers of adhesion-related incidents affecting suburban fleet of SWT, Southern Railway and South Eastern Trains in 2000 and 2005.

85 One further possible basis for comparing the adhesion-related performance of modern and older rolling stock is to use data from autumn 2004, this being the year when old and new fleets of main line stock used by Southern, South Eastern Trains and SWT were operating alongside each other over the same routes. It has not been possible to obtain exact figures for the amount of old and new stock operated by these three TOCs during autumn 2004 as the proportion of new stock was increasing throughout the period, but it is probable that old stock still accounted for approximately 30%-40% of the main line services operated collectively by the three companies. Figure 12 shows the involvement of each fleet in station overrun incidents during autumn 2004. It indicates that there was a disproportionate involvement of new stock in adhesion-related incidents. Although the Class 444 units operated by SWT appear to run counter to this trend, the fleet was the last to be introduced by SWT and may not have been fully operational throughout autumn 2004.



OLD [Class 411, 421, 423]
NEW [Class 375, 377, 444 and 450]

Figure 12: Occurrence of station overrun incidents during autumn 2004 - comparison of new and old classess.

86 Analysis of figures 9-12 shows that the modern rolling stock operated by South Eastern Trains, Southern and SWT was more susceptible to adhesion-related incidents than the older stock it replaced, despite having sophisticated WSP and sanding systems. However, Figure 13 shows that the number of adhesion-related incidents experienced with the four classes of modern rolling stock increased disproportionately between 2004 and 2005, suggesting that factors additional to those associated with the trains also contributed to the relatively high number of adhesion-related incidents in autumn 2005.

	2004	**2005**
Class 375	7	33
Class 377	5	28
Class 444	0	13
Class 450	7	46

Figure 13: Comparison between numbers of adhesion-related incidents experienced by Classes 375, 377, 444 and 450 - 2004 and 2005.

87 Reference was made in paragraph 76 to the performance of Classes 507/508, which are operated by three TOCs (in Merseyside, North West London and Kent/Sussex) and experienced different numbers of adhesion-related incidents in autumn 2005. The Desiro family of EMUs have similar characteristics and operates in different parts of the country. The number of adhesion-related events affecting each Desiro fleet is summarised below:

- The Class 444 and 450 units are operated by SWT predominantly over the Wessex Route (Surrey, Hampshire, Dorset and Berkshire). In autumn 2005, there were 45 five car Class 444 units in operation and 109 four car class 450 units in operation. There were 59 adhesion-related incidents affecting these units in autumn 2005.
- The Class 350 unit is operated jointly by Silverlink and Central Trains over the West Coast Main Line. In autumn 2005, there were 30 four car units in operation. There were no adhesion-related incidents affecting these units in autumn 2005.
- The Class 360 units are operated by 'One' (21 four car units) on main line services in Essex and Heathrow Express (5 four car units). There were three adhesion-related incidents affecting these units during autumn 2005 (two affecting units operated by 'One' and one affecting units operated by Heathrow Express).

88 The analysis of the Desiro fleets provides further evidence that it is not rolling stock characteristics alone that determine the number of adhesion-related incidents.

89 Improvements in suspension and bogie performance of modern stock give a better ride for passengers and help to reduce impact on the track when compared with the stock that it replaced. Although the ride quality for passengers on older stock might have been lower and resulted in more wear and tear on the track, it may also have cleaned a greater area of the rail surface than is the case with modern stock.

90 There is a degree of similarity in the ride characteristics of modern freight rolling stock and older passenger rolling stock. The Wessex route suffered 89 adhesion-related station overruns in autumn 2005, but there were none on the section of line between Basingstoke and Totton (west of Southampton) where there is a significant flow of container trains to and from the docks at Southampton and other traffic to and from the Fawley branch. There were adhesion-related incidents immediately to the east of Basingstoke and immediately to the west of Totton. Given the rural nature of the majority of this route, this provides tentative support for the theory that trains with more primitive suspension systems

are effective at cleaning contaminant from the rail head, which may provide a partial explanation as to why the modernisation of the passenger fleets operating in the south east has been accompanied by an increase in adhesion-related incidents.

Summary

91 The analysis contained in paragraphs 60 to 90 has shown that there was a different distribution of events throughout the autumn period for the three years (2000, 2004 and 2005). The distribution of events by length of overrun was similar for each of the three years, although there were detailed differences when analysed by time of day.

92 Geographically, there is a concentration of adhesion-related events in the south east, north west and Scotland but the low number of incidents occurring in the Midlands means that there is no correlation between density of traffic and numbers of incidents.

93 The characteristics of different rolling stock fleets operating over the national network vary. WSP and sanders are systems provided to deal with low adhesion conditions, but they are not available on all fleets. Units not equipped with sanders featured prominently in adhesion-related incidents in autumn 2005, but modern fleets equipped with WSP and sanders also experienced a significant number of incidents.

94 A comparison between the performance of modern stock in the south east during the low adhesion period and the stock that it replaces showed that despite the availability of WSP and sanders, modern trains appeared to be more susceptible to adhesion-related events. However, a review of similar fleets operating in different parts of the country showed that performance within fleets also varied, indicating that the characteristics of the rolling stock alone do not account for the high numbers of adhesion-related events experienced by some fleets.

95 The characteristics and distribution of adhesion-related incidents in autumn 2005 were affected by a complex range of factors. The analysis contained in the remainder of this report will show that adhesion performance in 2005 was affected by:

- infrastructure factors, including the identification of sites for rail head treatment and differences in practice with regard to the treatment given;
- rolling stock factors, including the availability and characteristics of WSP and sanding systems and the standards that help to shape those characteristics;
- operational and management factors, including driving policy and practice, briefing of drivers and the procurement and approvals processes for new rolling stock.

Assessment of causal and contributory factors

Infrastructure Factors

Introduction

96 This section contains an analysis of the causal and contributory factors for adhesion-related events associated with the infrastructure. It considers:

- the process used by Network Rail for determining which parts of the railway are subject to railhead treatment;
- different methods for treating the rail head to counter the effects of low adhesion;
- rail head treatment policy for autumn 2005;
- the relationship between different types of rail head treatment and adhesion incident occurrence rates in 2004 and 2005;
- short-term prediction of adhesion problems;
- delivery of rail head treatment;
- other infrastructure issues.

Process for determining railhead treatment

97 The process used by Network Rail to determine which parts of the network receive railhead treatment has been described in paragraph 34. The approach used for autumn 2005 focused primarily on historical performance and feedback from TOCs and infrastructure maintenance staff. It overlooked the fact that low adhesion conditions can remain undetected until a train is required to accelerate or stop and that approaches to junctions and some level crossings where trains do not normally stop do not have the benefit of railhead conditioning.

98 During 2006, Network Rail's Wessex route in conjunction with SWT developed and implemented a risk-based approach to identifying areas of low adhesion that takes account of the potential of low adhesion incidents to cause disproportionate harm at key locations such as junctions and level crossings. This facilitates the identification of potential low adhesion locations that require special attention.

Methods of rail head treatment

99 Paragraph 36 describes the methods employed by Network Rail to treat the rail head. Network Rail and its predecessor organisations performing the role of Infrastructure Manager for the national network have experimented with novel methods of rail head treatment to improve adhesion including surface scrubbing and laser cleaning. However, the methods have proved to be impractical (lasers only work at very low speed and brushes wear out rapidly).

100 The techniques that have been used most widely and consistently are water jetting and the application of Sandite. There is an important distinction between the effect of water jetting and Sandite. The purpose of water jetting is to clean the rail head. The purpose of applying Sandite is to enhance adhesion levels at the wheel/rail interface but there is a risk that if it not applied properly, it can act as a contaminant and prevent trains from operating track circuits.

101 Research and testing to determine the best method for treating the rail head has been carried out over a number of years. Network Rail undertook testing on the Ministry of Defence railway at Bicester in spring 2003 to try to identify the optimum method of treating the rail head. The results of this and subsequent tests are included within the AWG report into low adhesion incidents in autumn 2005. The report states that the tests demonstrated:

- water jetting was effective for cleaning the rail head at the low speeds employed in the tests;
- sandite improves rail head adhesion and is not detrimental to train detection if it is properly spread over the surface of the rail by the MPV.

102 During autumn 2003 Network Rail measured the effectiveness of water jetting and Sandite and concluded that both methods were effective in achieving their purpose 'to some degree'. In spring 2004, trials were undertaken at Bury in order to test the effectiveness of water jetting at 40 mph (65 km/h) (speeds that were not achievable on the MOD site at Bicester). The trials at Bury were also used to test different nozzle configurations for the water jet. The results from the Bury trials showed that:

- water jetting on rail treated with an unmodified nozzle at a speed of 30 mph (50 km/h) gave an improvement of 40% in braking performance when compared with braking on untreated rail;
- the modification to the water jet nozzle gave an improvement in braking performance of 70% at a speed of 30 mph (50 km/h) when compared with braking on untreated rail;
- if MPV speed was increased to 40 mph (65 km/h), the improvement in braking performance when compared with braking on untreated rail was 45% with the modified nozzle;
- the optimum application speed for Sandite was 30 mph (50 km/h) and that it was an effective way of improving braking performance in low adhesion conditions.

103 Taking the effectiveness of water jetting into account and also considering that the slower speed at which Sandite had to be applied represented a disadvantage in terms of finding *train paths* for the MPV, Network Rail concluded that water jetting at 40 mph (65 km/h) was the most effective form of rail head treatment for all but severe low adhesion conditions. On days when low adhesion conditions were expected to be severe, Sandite would be required in addition to water jetting.

Railhead treatment policy for autumn 2005

104 Although Network Rail had the results from the trials at Bury available before autumn 2005 there was no central direction on which methods of rail head treatment should be applied nationally. Network Rail routes made their own decisions about the rail head treatment that would be applied. In 2004, all routes had employed water jetting and Sandite. In 2005, the option was available to employ water jetting alone. The treatment applied to each route is summarised in Figure 14.

Route	Rail head treatment	Comments
Anglia	Water jet	
Chiltern	Water jet/Sandite	The Chiltern TOC treats the infrastructure south of Bicester using its own equipment
Kent	Water jet and water jet/Sandite	Water jet only to mid-November, water jet & Sandite thereafter
London North Eastern	Water jet/Sandite	GN north of Peterborough, Hertfordshire Loop and Cambs Branch daytime water jet only
London North Western	Water jet	Watford DC and Merseyrail water jet/Sandite
Scotland	Water jet and water jet/Sandite	Water jet only to end October, water jet/Sandite thereafter
Sussex	Water jet/Sandite	
Wessex	Water jet	
Western	Water jet and water jet/Sandite	Water jet & Sandite west of Newton Abbot and on main line in Cornwall from 9 November

Figure 14: Methods of rail head treatment during autumn 2005.

Relationship between railhead treatment and incident occurrence rate

105 Figure 15 shows the proportion of adhesion-related incidents attributable to the eight routes plus Chiltern in 2004 and 2005.

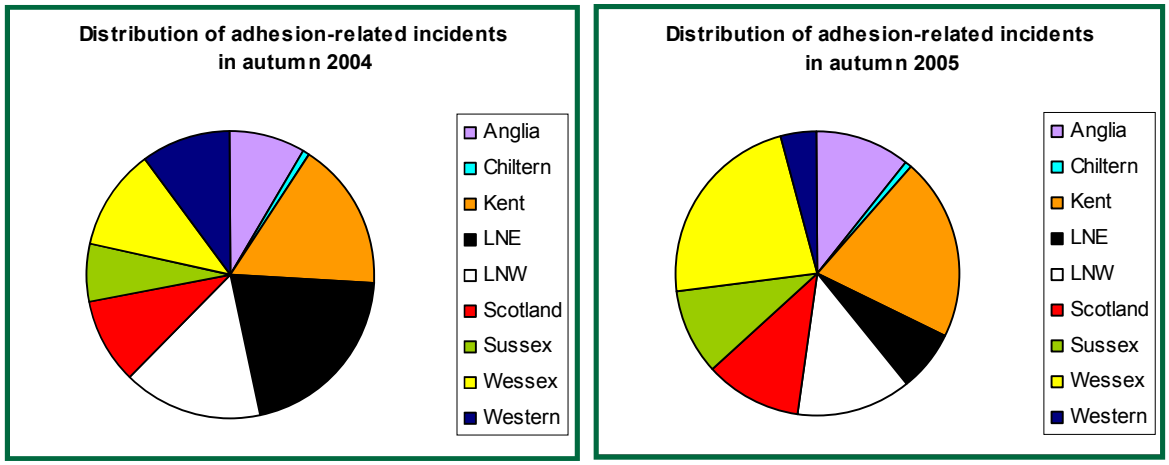


Figure 15: Distribution of adhesion-related incidents in autumn 2004 and autumn 2005.

106 Figure 15 presents a mixed picture. Wessex, a route that changed from water jetting and Sandite in 2004 to water jetting only in 2005, was responsible for a higher proportion of the total number of adhesion-related incidents in 2005 than 2004. However, Sussex, which used water jetting and Sandite both years, also saw an increase in its proportion of adhesion-related events. Conversely LNW, which also moved from water jetting and Sandite in 2004 to predominantly water jetting only in 2005 saw a decrease in its proportion of adhesion-related incidents over the two years. The most dramatic decrease in occurrence rate occurred on LNE route, where there was a reduction in the use of water jetting and Sandite in 2005, but not eradication.

107 In Kent, Scotland and Western, rail head treatment for all or part of the route changed from water jetting only to water jetting and Sandite during the autumn period and this further complicates the analysis. In these three cases, the type of treatment changed because the principal TOC in that area had asked for Sandite to be applied.

108 In Scotland, the change coincided with a reduction in station overruns although this could have been attributable to the fact that in Scotland, autumn tends to start and finish earlier than in the southern half of Britain, and the second half of autumn normally features fewer adhesion-related incidents than the first. However, on the Edinburgh-Glasgow route, it was not possible to use Sandite in the second half of autumn because of lack of train paths. Although there was a reduction in the number of incidents on this route after the reversion to the use of Sandite elsewhere, the reduction was not as dramatic as the reduction on the routes where Sandite application was reinstated. This supports the outcome of the trials conducted by Network Rail (paragraphs 101 and 102) with regard to the effectiveness of Sandite.

109 Overall, because of the contradictory nature of the evidence, it is not possible to be certain about the circumstances under which water jetting alone or water jetting and Sandite in combination is the optimum railhead treatment policy. As the numbers of 'failure to operate track circuit' incidents remained fairly constant between 2004 and 2005, no immediate benefit for the greater use of water jetting can be claimed in this respect. Sandite improves adhesion but the lower operating speed for MPVs applying Sandite in autumn 2005 meant that the extent of railhead treatment over the network would have been lower than was achieved by employing a combination of the two methods.

110 In June 2006, further rail head treatment tests were undertaken at Bury. Network Rail reported that the findings from the tests showed that the effectiveness of water jetting with Sandite was the same for a Sandite flow rate of 4 litres/minute at 30 mph (50 km/h) and 2 litres/minute at 40 mph (65 km/h). Network Rail considered that the trials had shown that Sandite could now be laid effectively at 40mph (65 km/h) providing that it was laid at the lower flow rate. Network Rail also concluded that water jetting and Sandite is a more effective method of rail head treatment than water jetting alone. For autumn 2006, Sandite has been applied at speeds of 40 mph (65 km/h) at the lower flow rate of 2 litres/minute. A small number of MPV circuits employed water jetting alone, in agreement with the relevant TOCs.

111 The effectiveness of Sandite diminishes over time. The speed with which this takes place is directly related to usage, i.e. the number of wheels that pass over the treated rail. Network Rail's own assessment is that Sandite is only effective for the passage of 100 axles (which would equate to three hours for routes over which two four-car trains per hour are operated). Sandite can also be washed off by rain. Water jetting was claimed by Network Rail to be effective for up to eight hours. Although no evidence has been seen to support these assertions, it is likely that the rate at which the effectiveness of Sandite diminishes will be affected by the intensity of train service operating over the route.

112 A number of changes have been made to the rail head treatment regime in the last few years and, as explained in paragraph 110, further changes were made for autumn 2006. While each of the trials helps to advance knowledge on rail head treatment, this can only be validated by operational experience over more than one autumn. Network Rail is committed to the continuation of trials and consultation with TOCs in order to inform future policy decisions on rail head treatment. Changes in rail head treatment technology are likely to bring with them the need for further trials. The optimum method for treating the rail head will change over time. It is important that the rail head treatment strategy for each autumn is based on sound evidence that it constitutes the optimum approach. The outcome from trials is a significant input to that strategy as is experience from previous autumns.

Short-term prediction of adhesion problems

113 Network Rail establishes its rail head treatment policy well in advance of the autumn period, but this is subject to short-term modification depending on forecasts of conditions that could result in poor rail head adhesion. The *ADAS classification system* is used to predict likely adhesion conditions on each specific day in the autumn, a process which starts with a five day forecast and is then refined over the next five days. During autumn 2005 the accuracy of the ADAS system was inconsistent in its prediction of the days when the highest number of adhesion-related incidents would occur. Figure 16 shows a comparison between the worst 5 days for autumn predicted by ADAS and the worst 5 days as actually experienced in autumn 2005:

	Good correlation between ADAS predicted ranking and actual ranking		**Poor correlation between ADAS predicted ranking and actual ranking**	
	ADAS Prediction *	**Actual ***	**ADAS Prediction***	**Actual ***
24 October			5	26
25 October			3	18
28 October			20	4
3 November	1	2		
8 November	4	6		
11 November	2	5		
25 November			14	1
16 December			29	3

* 'ADAS Prediction' refers to the ranking of that day in relation to the 85 days of the autumn period where '1' represents the worst predicted day for adhesion related incidents. 'Actual' refers to the actual ranking of that day in relation to the 85 days of the autumn period where '1' represents the worst actual day for adhesion-related incidents

Figure 16: Comparisons of ADAS predictions with actual experience.

114 The good standard of predictions for 3, 8 and 11 November shows that the ADAS system is capable of producing useful data and a forewarning to the industry of difficult days. The value of good predictions is that they enable Network Rail to take additional measures to cope with severe conditions, as described in paragraph 37. The poor predictions for 28 October, 25 November and 16 December show that there is scope for improvement. There should be ample evidence from last autumn to establish why high numbers of adhesion-related incidents occurred on days when the forecast was relatively benign.

115 In autumn 2005, the ADAS system produced area-specific forecasts for 16 areas across the network, grading the risk as low, medium, high or extreme. This resulted in the application of the forecast to relatively large areas when, conversely, the phenomenon of low adhesion can be localised:

- On 28 October 2005, there were 12 adhesion-related incidents in Scotland, including two within a few minutes of each other at the same location (but involving trains running in opposite directions). The ADAS prediction for this part of the network on 28 October was medium risk.

- Reference was made in the Part 1 report on the SPAD at Esher to the occurrence of 15 other adhesion-related incidents on 25 November 2005 within a 25 mile radius of Esher between 06:00 hrs and 09:00 hrs, with two other incidents occurring within a five mile radius between 06:15 hrs and 07:05 hrs. The ADAS prediction for this part of the network on 25 November was medium risk.
- On 8 December 2005, two adhesion related station overruns affected successive stopping trains at Hook and Fleet within 15 minutes of each other, the stations being located six miles apart. The ADAS prediction for this part of the network on 8 December was low risk.
- On 12 December 2005, three adhesion-related station overruns occurred on the Cobham line at Claygate, Cobham and Effingham Junction within the space of two hours (20:50 hrs – 22:55 hrs), over six route miles of railway. The ADAS prediction for this part of the network on 12 December was low risk.
- On 16 December 2005, the Hertford loop was closed at the end of the morning peak following overruns at the adjacent stations of Grange Park (07:14 hrs) and Winchmore Hill (07:45 hrs and 08:35 hrs) and numerous reports from drivers of adhesion difficulties. It was afternoon before the route could be reopened. The ADAS prediction for this part of the network on 16 December was medium risk.

116 The examples contained in paragraph 115 show that poor adhesion conditions can be prevalent in a localised area for a relatively short period of time. London Underground and Metronet Rail (BCV) have, since 2001, been operating a system on the Central Line that employs a number of sensors to detect changes in humidity at different sites. The system was needed because Central Line trains normally operate in *automatic train operation (ATO) mode* with the braking regime configured for normal adhesion conditions. If low adhesion conditions are present manual driving is employed and it is thus important to have an accurate prediction of adhesion conditions. Using measurements of moisture locally in conjunction with predictions regarding leaf-fall and train speeds in the open sections of the Central Line, the system provides a real time risk ranking, which can be used by Line Controllers to decide whether trains can be allowed to continue to operate in ATO. The system has been refined and consideration is now being given to its extension to other London Underground lines.

117 The AWG has embarked on developing an Adhesion Management System for the national railway network based on the system in place on the Central Line, with the objective of achieving timely and accurate identification and reporting of low adhesion conditions on the main line network. Development testing of the system is taking place on the Chiltern Lines during autumn 2006.

Delivery of rail head treatment

118 The report prepared by AWG on low adhesion events in autumn 2005 makes reference to difficulties in determining an overall picture of the number of occasions when there was a failure to deliver planned treatment of the network by MPVs. As an example (which is not necessarily representative of the nationwide picture), the performance of MPVs in Kent in autumn 2005 showed that a number of factors affected the delivery of railhead treatment. Network Rail's Kent route has five MPV circuits, which are operated twice a day. Two further MPVs are held in reserve for rapid response purposes. In the period between 3 October and 7 December 2005:

- There were only 3 occasions when a complete circuit did not operate because of an MPV not being available, representing a MPV availability rate of 99.5%.

- On 17 occasions, one circuit was cancelled by Network Rail. This, together with the three circuits affected by non-availability of MPVs, was equivalent to 3% of all planned circuits being cancelled.
- On 65 occasions, parts of one circuit were not delivered for various reasons, mainly because of mechanical problems on the MPV or because it ran out of water.
- The overall success rate for the MPVs in Kent in achieving their complete circuits as scheduled was 87%.

119 Network Rail, while endeavouring to operate all rail head treatment trains, also advises TOCs if it has not been possible to treat a particular part of the network. This information is cascaded to drivers via *late notice arrangements*.

Other infrastructure issues

120 The suspension system and ride characteristics of modern rolling stock are superior to older stock (paragraph 90). One consequence of this is that modern stock only makes contact with (and cleans) a narrow strip of the rail head. The rail head in areas where only modern rolling stock operates shows a narrow wheel contact path, i.e. a consistent point of contact. All the forces imparted from the train in normal running are applied to this narrow contact strip. There is no cleaning of the remainder of the rail surface by the passing of trains. However, there is no reason why train wheels should follow a different path in traction, coasting and braking, which means that the narrow contact strip is of no relevance to the causes of incidents in low adhesion conditions.

121 The braking rate achieved by trains using the national network is dependent on the level of adhesion available at the interface between wheel and rail. Modern trains are required by RGS to brake at a rate of at least $0.9m/s^2$ in full service (step 3) braking (higher values apply for some fleets). Braking in steps 1 and 2 results in decelerations at $0.3m/s^2$ and $0.6m/s^2$ respectively. A braking rate of $0.9m/s^2$ will be achievable only if an adhesion level of approximately 0.09 (paragraph 9) is available at the wheel/rail interface. Wheelslide occurs when the required braking rate of the train, as requested by the driver in selecting brake step 1, 2 or 3, cannot be matched by the level of adhesion available at the wheel/rail interface. Some trains are equipped with *stepless brake controllers* which permit a greater degree of control over the brake rate demanded, but the principle of the braking rate demanded being affected by the level of adhesion available remains the same.

122 During autumn, the level of adhesion may drop to below 0.03 as a result of the presence of rail head contamination. If adhesion levels drop below 0.03, a train will experience wheelslide as soon as brake step 1 is selected by the driver.

123 It is possible that sustained lengths of low adhesion are a more common phenomenon now than was the case fifteen years ago. In the early 1990s, a *tribometer train* ran over the national network to establish the prevailing levels of adhesion. At that time, average adhesion levels of 0.04 over significant distances were found, but the train took measurements over a limited part of the network. In the SPADs at Esher and Lewes, and in the case studies included at Figure 3, the average levels of adhesion available were below 0.02 in some areas. Data gathered in the 1990s by the tribometer train is still used to test and optimise WSP systems.

124 Reference was made in paragraph 32 to the problems associated with severe low adhesion conditions and the invisible contamination that was the cause of the SPAD at Esher. This phenomenon is not well understood currently. In particular, there is a need to understand what form this contamination takes, how it attaches itself to the rail head and the circumstances under which it becomes a particular threat to the operation of the railway. Only with this understanding can appropriate strategies for dealing with the causes of severe low adhesion be developed.

Infrastructure factors – key issues

125 The analysis contained in paragraphs 97 - 124 has shown that the following infrastructure factors are relevant to the high number of adhesion-related events experienced during autumn 2005:

- The approach to the identification of high-risk low adhesion areas on the national rail network was biased towards historical data and recent performance rather than risk arising from the configuration of the infrastructure (e.g. junctions and level crossings) (paragraph 97).
- Uncertainty over the optimum method for treating the rail head resulted in different methods of treatment being employed across the network. There is contradictory evidence from autumn 2005 with regard to the optimum strategy for railhead treatment (paragraph 109) and further changes made for autumn 2006 need to be validated (paragraph 112).
- There was variable performance in the prediction of low adhesion conditions. The overall accuracy of rail head condition prediction using the ADAS system throughout autumn 2005 was unreliable (paragraphs 113-115).
- Significant lengths of low adhesion were experienced on a number of occasions during autumn 2005 and it is possible that they are now occurring more frequently than has been previously thought to be the case (paragraph 123).
- There is a lack of understanding regarding the mechanisms that create severe low adhesion conditions including invisible contamination and methods for treating it (paragraph 124).

Rolling Stock Factors

Introduction

126 It was shown in paragraph 80 - 86 and accompanying figures that modern rolling stock in the south east had featured more prominently in adhesion-related incidents in autumn 2004 than older stock. The review of infrastructure issues has shown that variability in the way that the infrastructure was treated may have had an impact on performance but there are issues associated with rolling stock that also need to be considered. Most modern fleets are equipped with software driven WSP systems and sanding, which were not installed on the fleets they replaced. These systems should give modern rolling stock an advantage in stopping in low adhesion conditions. In seeking to understand why modern rolling stock has experienced a high number of adhesion-related incidents and what can be done to improve performance, the following areas have been considered:

- the requirements of RGS and TSI;
- technical characteristics of modern trains, particularly WSP, sanding and braking;
- testing and validation of WSP systems;
- alternative methods for stopping trains in low adhesion conditions.

Standards (Railway Group Standards (RGS) and Technical Specifications for Interoperability (TSI))

127 RGS have traditionally provided a framework to govern the specification, design and operation of infrastructure and rolling stock on the national railway network. However RGS have been or will progressively be superseded by TSIs. TSIs are the consequence of the European Economic Community's (EEC) wish to promote the interoperability of rail services throughout Europe. To implement this aim, the EEC published Interoperability Directives in 1996 for high speed lines and in 2001 for other lines that fall within the scope of the Trans European Network (TEN). They set out a number of 'essential requirements' to be met for interoperability, including safety requirements for products and subsystems (trains, signalling, infrastructure, etc).

128 TSIs define the specifications to satisfy these essential requirements and are also divided into two groups, high speed TSIs covering the high speed lines (Channel Tunnel Rail Link, East Coast Main Line, West Coast Main Line and Great Western Main Line in Britain) and conventional TSIs covering the TEN lines.

129 The high-speed TSIs are already in force. The implementation dates for the conventional TSIs vary. The Control Command and Signalling Conventional TSI is published and in force. The conventional TSIs covering freight wagons will come into force shortly but those for locomotives, traction units and passenger carriages will not be in force until 2010 at the earliest.

130 For multiple units, the high-speed TSIs covers rolling stock designed to operate at speeds above 190 km/h (approximately 120mph). This means that only 4% of the multiple units operating in this country are covered by existing TSIs. The conventional TSI for rolling stock is at an early stage of drafting and the requirements of the rolling stock RGS will therefore remain relevant for some time to come.

131 There are a limited number of requirements in RGS on performance of rolling stock under low adhesion conditions. GM/RT2044, 'Braking System Requirements and Performance for Multiple Units' mandates the provision of WSP systems on new disc braked rolling stock and states:

> 'If disc brakes are fitted to the vehicle, a WSP system shall be fitted that ensures that the braking force is controlled, where applicable on a per axis basis, to minimise the extension of stopping distance due to low adhesion.'

132 GM/RT2045, 'Braking Principles for Rail Vehicles' defines braking performance of trains generally, but states:

> 'The braking performance defined in these documents (which include GM/RT2044) relies on the normal level of adhesion being available that is necessary to sustain the brake retarding force demanded. It is accepted that in conditions of low wheel/rail adhesion the friction force that can be maintained at the wheel/rail interface is reduced and other measures to achieve the required stopping distance are necessary such as reduction in speed, railhead surface conditioning or a means of braking that does not rely on the wheel/rail adhesion.'

133 GM/RT2045 lays down requirements for maximum air consumption by WSP to ensure that the braking system does not run out of air. However, there are no quantified criteria for acceptable stopping distances under low adhesion conditions mandated in any RGS. A draft of the revised high speed TSI for rolling stock includes criteria for maximum stopping distances under low adhesion conditions. As currently drafted, it requires specified braking rates to be achieved at defined speeds, irrespective of available adhesion. The implication is that trains must 'artificially' create any shortfall between the required braking rate and the level of adhesion available, using other means such as WSP systems and sanding to do so.

134 GM/RT2461, 'Sanding Equipment Fitted to Multiple Units and On-Track Machines' mandates the fitting of sanders to all new multiple units of previous uncertified design with a Certificate of Conformance for Vehicle Design signed on or after 4 December 2003. It lays down that sanders must:

- In braking mode, as a minimum, discharge sand during full service and emergency brake applications when the presence of low adhesion is automatically detected.
- Operate when WSP indicates wheel speed at 95% or less than train speed.
- Deliver sand from the leading vehicle only at a location forward of the third axle in direction of travel and there must be at least six axles behind the laying position of the sand.
- Achieve a maximum sanding density of 7.5 grams/metre on the rear most two axles of the train. Guidance is also included that indicates this is equivalent to a maximum dispensing rate of 2kg/minute per rail. In order to convert the sanding density to a sanding rate, a dispensing speed of 10 mph (16 km/h) has been assumed. Thus trains running at 10 mph will lay sand at a density of 7.5 grams/metre if the sanding rate is set at 2kg/minute.

135 The purpose of these requirements is to provide minimum standards for configuration of sanding equipment. They have the effect of limiting the amount of sand that can be dispensed. The requirement for six axles behind the point at which sand is delivered is included to ensure that sand is distributed along the surface of the rail, but also has the effect of preventing the single coach Class 153 units and two axles per vehicle Classes 142-144 units from being equipped with sanders.

136 The restrictions applied in RGS GM/RT 2461 are based on concern that too much sand applied at low speed might result in trains being unable to operate track circuits due to sand acting as an electrical insulator between the wheel and the rail. Track circuits are used, inter alia, to control the aspects displayed by colour light signals. If a stopped train failed to operate a track circuit, it is possible that a signal located immediately behind it could, instead of displaying a red aspect, display a yellow or green aspect.

137 More sophisticated systems are available that link sanding rate to train speed. For these systems, derogation from the requirements of GM/RT2461 has been granted and a higher maximum dispensing rate of 4kg/min is permitted with safeguards in the form of low speed cut-off to ensure that sanding at this rate does not take place when the train is travelling at low speed.

Standards – key issues

138 The review of the requirements of RGS and TSI in paragraphs 127 to 136 has shown that:

- there are no requirements within RGS on maximum braking distances under low adhesion conditions (paragraph 133);
- some units are specifically excluded from being fitted with sanders by RGS (paragraph 135).

Technical characteristics of modern trains (WSP, braking, sanding)

Wheelslide Prevention (WSP) Systems

139 This section addresses WSP systems, looking specifically at how WSP systems work and their characteristics.

140 Around 90% of vehicles operating within passenger multiple units on the national railway network are equipped with a WSP system to control braking on a sliding train. The primary function of the WSP system is to limit the extent of wheelslide in order that effective use is made of the available adhesion on the rail head. A further function of the WSP is to prevent wheels locking up and the consequent damage to the wheel tread. The system works by detecting wheelslide and then regulating the rotational speed of the wheels by means of the controlled release and re-application of the brakes. On trains not fitted with WSP systems drivers are instructed to release and apply brakes when experiencing adhesion difficulties in order to find a braking rate that the available adhesion will support.

141 The controlled slip achieved by a WSP system also facilitates the conditioning of the rail head by the wheels. Conditioning can be beneficial because it improves adhesion for following wheels on the same train, although the effectiveness of conditioning is itself influenced by the level of adhesion available (the lower the level of adhesion, the lower will be the benefit from conditioning). Conditioning is also influenced by train length. There is evidence to suggest that the longer the train, the greater the benefit from conditioning., Analysis of data from the incidents at Esher and Lewes (see the part 1 and 2 reports) showed that there is some limited benefit to be obtained from conditioning even with short (four coach) trains (paragraph 66).

142 The process of applying and releasing brakes is achieved pneumatically, which limits the speed and sensitivity with which the braking system can respond to changes in demand because of the pneumatic time constants of the braking system and factors such as wheel inertia which also influences speed of response.

143 WSP systems have been available for a number of years with the result that there are differences in the level of sophistication offered by the system, depending on its age.

144 Information provided by AEA Technology and Interfleet explains the difference between older and more modern WSP systems. Earlier WSP systems modulated the brake cylinder pressure by energising and de-energising a 'blowdown valve', which had a single port. This meant that brake cylinder pressure was either at maximum or heading to zero. Only through rapid operation and chokes in the port could intermediate pressure be achieved, allowing some primitive modulation of brake pressure. Later trains have what are termed 'two stage valves'. Two solenoid valves are controlled individually by the WSP electronics such that with both de-energised, air can pass freely to the brake cylinder but by selective energisation of the two valves, the pressure in the brake cylinder can be vented and/or held at an intermediate pressure. Thus the braking force of an individual wheelset can be more accurately regulated to the prevailing adhesion. In addition, modern WSP systems can be adjusted to enable a finer level of control to be achieved.

145 A simplified overview of the operating logic of a WSP system during train braking is provided at Figure 17.

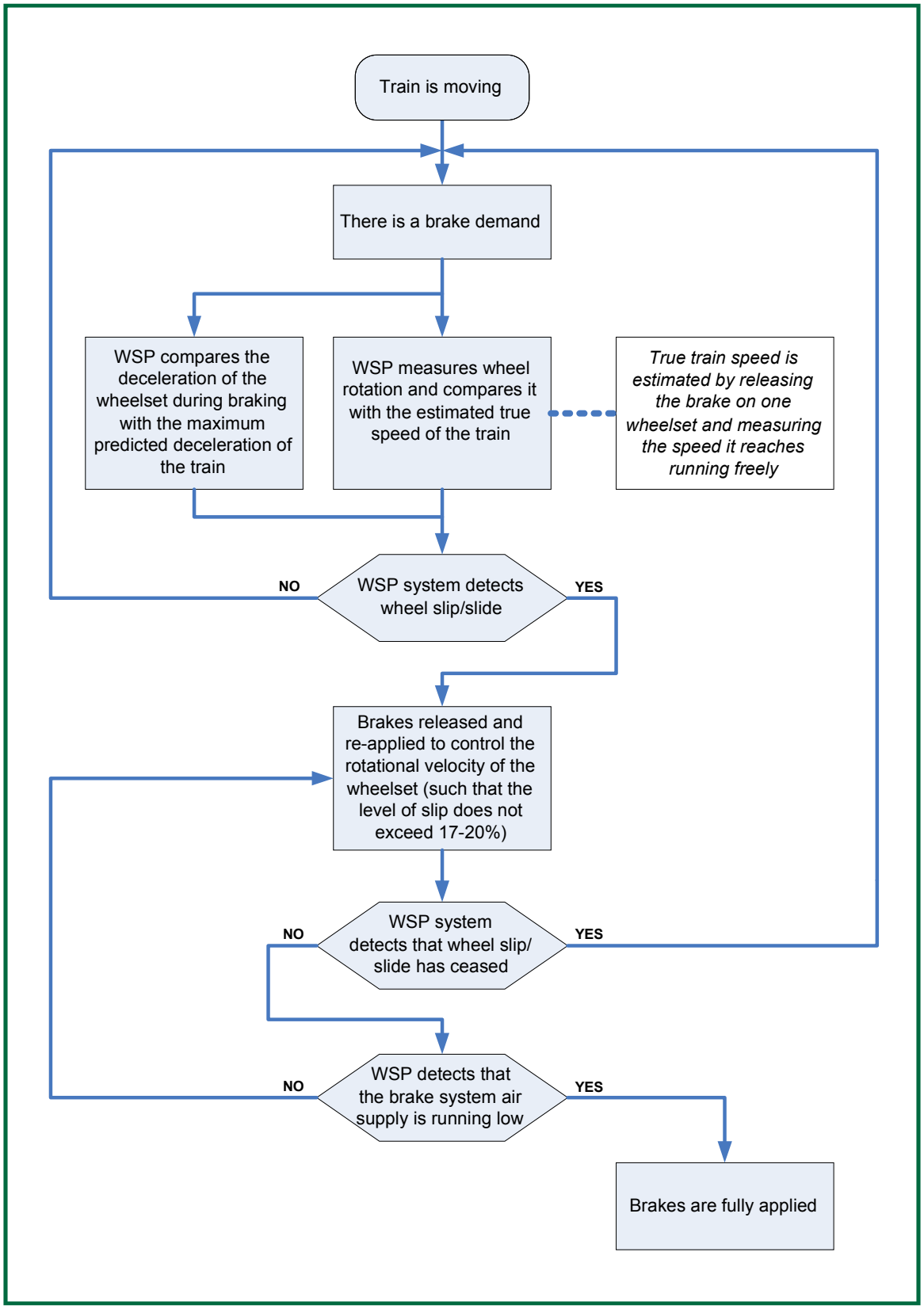


Figure 17: A simplified overview of the logic of a typical modern WSP system when operating during train braking.

146 WSP systems limit the extent to which wheels are allowed to rotate below the real speed of the train. On rolling stock operating over the national rail network, the extent of slip permitted by the WSP system is limited to 17%-20%. A report commissioned by RSSB and prepared by AEA Technology (made available to the RAIB in draft form during the preparation of this investigation report) describes why this level of slip is used on rolling stock operating on the national rail network. It identifies two factors:

- The peak of adhesion occurs at around 1% slip, after which the available adhesion falls away. The control system for WSP requires a linear response to control actions. A slip level in the region of 15%-20% coincides with a linear negative slope that the control system designer can utilise.
- Historically, the testing of WSP systems was undertaken on test tracks with the rails treated with a detergent mixture. This approach resulted in the creation of levels of adhesion at the wheel/rail interface of about 0.06 (see paragraph 9). The best WSP performance at this level of adhesion has been achieved with a slip parameter of 15%-20%, although it may not be optimum for lower levels of adhesion. However, given that trains will encounter variable levels of adhesion, it may not be possible to optimise WSP performance for all conditions encountered.

147 A key issue is whether the slip rate of 17-20% is an appropriate level for meeting the objectives of avoiding damage to wheels and minimising extension of stopping distances. There appears to be no question that it contributes towards the objective of avoiding damage to wheels. TOCs with modern rolling stock equipped with WSP systems report a dramatic reduction in the occurrence of wheel flats, a problem particularly associated with older rolling stock not equipped with WSP. However, the investigation has considered whether there may be an alternative control strategy that would deliver improved stopping distances.

148 There is data available from research in this area[6] Based on information contained within this reference, the advantages and disadvantages of configuring the WSP to control wheel speed to different levels of slip are summarised in Figure 18.

[6] AEA Technology, 'Train Control System Influence on Adhesion Performance', Issue 1, September 2006, Ref AEAT/RAIL/LRIS/LD82057/RP02 Issue 1. This is the most recent research but it also references other work undertaken in this area.

Level of Slip	Designation	Advantage	Disadvantage	Comment
Around 5%	'micro slip'	• Maximises use of the available adhesion	• Degree of control difficult to achieve with pneumatic brake systems because of speed of actuation	May be compatible with hydraulic braking systems
17-20% (currently employed)	'macro slip'	• This degree of control can be achieved with a high degree of reliability while making reasonable use of the available adhesion • Generates sufficient heat/friction to condition the rail head. • Wheel damage will be avoided	• Not as efficient as 'micro slip' in exploiting available adhesion. • Rail head conditioning may not be maximised	This level of slip is currently provided in the WSP systems provided on rolling stock operating over the mainline network
60%+	'deep slip'	• Can maximise benefit of rail head conditioning. • Under certain circumstances the formation of wheel flats can provide further retardation to the train. • Provides shortest stopping distance once better adhesion is encountered	• Inefficient utilisation of the available adhesion • Railhead conditioning dependent on there being sufficient adhesion to generate energy at wheel/rail interface. • Wheel damage is likely to occur.	The additional benefits of rail head conditioning have yet to be measured.

Figure 18: Summary of advantages and disadvantages of different WSP control strategies.

149 Figure 18 shows that there are some significant difficulties with brake control strategies that are different from those currently employed on modern rolling stock (17-20% slip). The ability to improve on stopping distances relates to the brake demand, vehicle dynamic properties and the available adhesion level as well as the level of slip. In a section of line where low adhesion is present the actual level of adhesion throughout the affected section is likely to vary (i.e. there will be peaks and troughs). If the WSP is operating at a reduced level of slip it is able to take more advantage of the available adhesion (i.e. it is working at a value nearer to the peak of adhesion and thus the value of utilisation is effectively higher). Provided there is sufficient brake effort available, the train will stop in a shorter distance.

150 Conversely, it is also possible that the stopping distance of a train in severe low adhesion conditions might be minimised if some or all wheels on the train were allowed a deeper level of slip than the normal 17%-20%. This might improve rail head conditioning. While this is by no means certain, simulation might help to determine if stopping distances could be reduced by employing deeper levels of slip. As increasing the level of slip might cause wheel damage (and damaged wheels can also cause damage to railway infrastructure), deeper levels of slip could only be contemplated for severe low adhesion conditions.

WSP – key issues

151 The analysis contained in paragraphs 140 to 150 has shown that the following is a key issue with regard to WSP systems:

- the longer the train, the greater will be the benefit from rail head conditioning (paragraph 141);
- although the 17-20% slip' parameter for WSP systems is well suited to the reliable stopping of trains in most low adhesion conditions, further consideration of higher and lower levels of slip will help to determine whether an alternative approach is better for severe low adhesion conditions (paragraphs 147-150).

Testing of WSP systems

152 This section addresses the testing of WSP systems. It describes the WSPER® simulator used for testing WSP systems fitted to modern rolling stock operating in this country and compares elements of the WSPER® simulator testing regime with the track-based testing mandated under *International Union of Railways* (UIC) requirements. It also includes some observations on deficiencies within the current WSP testing regime.

153 Testing of WSP systems is required to demonstrate compliance with RGS requirements on air consumption (paragraph 133). Although testing is required, there is no requirement to use a specific test facility or technique. The railway industry in Britain uses AEA Technology's (AEAT) WSPER® simulation and testing facility to test and optimise the performance of WSP systems. The WSPER® consists of a computer control system, a system for emulating the dynamics of the vehicle and its braking system and a transducer. These are connected to a compressor, blowdown valves, pipework and cylinders from (or equivalent to) the system itself. WSPER® is thus a hybrid test rig and simulator. It tests vehicles individually. A normal programme would include simulation of the performance of a single power car and a single trailer car. The data on adhesion conditions within WSPER® is based on the data gathered by the tribometer train in the 1990s (paragraph 123) A validation exercise for the WSPER® was also undertaken in the early 1990's, involving comparisons between braking data from a class 319 EMU on the Midland Main Line and tests on the WSPER®.

154 Paragraphs 131-133 indicate that while WSP systems are mandated on modern disc braked rolling stock there are no quantified stopping criteria contained within RGS against which the performance of WSP systems can be tested.

155 AEAT in conjunction with other railway industry partners including Interfleet and HSBC has developed acceptance criteria for WSP systems tested as part of an approvals programme for new rolling stock. In the first instance, model stopping distances are calculated by WSPER® based on a brake demand that exactly matches the maximum adhesion available at each point along the profile. Acceptance criteria are then developed which permit the WSP system on test to exceed the model stopping distance by a predetermined maximum figure (see paragraph 157). There have been minor revisions to the criteria following reviews of actual performance by WSP systems on test.

156 When WSP systems on new rolling stock are being tested, two types of test are run on WSPER®. The first group of tests simulate 'naturally occurring variable adhesion' conditions, based on adhesion measurements taken across the main line network in the early 1990s. A series of ten simulations are made over a group of adhesion profiles for different load and speed conditions. This value is compared with the actual stopping distance achieved by the WSP to determine how the performance of the WSP system under test compares with the criteria.

157 The results of the ten simulations are considered individually and as a group to establish whether AEAT's criteria have been met:

- individually, the predicted stopping distance of each simulation must not exceed the model value by a percentage that is dependent on the simulated initial speed (eg 90% for an initial speed of 25 mph (40 km/h), 35% for an initial speed of 75 mph (120 km/h));
- collectively, the average predicted stopping distance from the ten simulations must not exceed the model value by a percentage that is dependent on the simulated initial speed (e.g. 27% for an initial speed of 25 mph (40 km/h), 7% for an initial speed of 75 mph (120 km/h)).

158 Other criteria on maximum permissible air consumption and the accuracy of the prediction of speed by the WSP reference wheel also need to be met and there must be no locking up of the wheels above a speed of 6 mph (10 km/h). Performance against these criteria is also assessed using the simulations undertaken on the WSPER® rig.

159 A second set of simulations are undertaken on the WSPER® for sustained low adhesion conditions, defined as 0.02-0.06. For these simulations, the pass or fail criteria with regard to stopping distances described in paragraphs 155 and 157 do not apply. The only criteria used to determine whether a WSP system has passed are air consumption and no locking up of the wheels (as required by RGS GM/RT2044).

160 An alternative test specification for WSP systems is provided by the UIC. A key difference is that the UIC specification (which was first issued in January 1985 and updated in November 2005) requires live testing with levels of adhesion artificially reduced with detergent rather than simulation. Testing of the whole unit takes place rather than simulation of the performance of individual vehicles within the unit. There are differences between the UIC test specification and that used for systems being tested on the WSPER®. Some examples are tabulated in Figure 19:

Parameter	UIC	WSPER®
Permissible extension to stopping distance at 75 mph (120 km/h)	25%	35%
Highest permissible speed for lock up	19 mph (30 km/h)	Below 6 mph (10 km/h)
Locking up time limitation	0.4 seconds	None
Level of adhesion simulated	0.05 -0.08	0.02 – 0.14

Figure 19: Comparison between UIC and WSPER test specification.

161 The UIC specification for testing is not favoured in Britain. Early WSP systems used on trains running over the national rail network were tested using the UIC specification. However, the performance of these systems in this country was considered poor (wheelsets were still being damaged) and this provided the impetus for a method of testing that was based on adhesion conditions in this country and the development of the WSPER®.

162 Another reason that WSPER® is preferred in Britain is because there is scepticism about the method by which low adhesion is generated in live testing, which requires the use of a detergent spray immediately in front of the leading wheels of the train being tested. Detergent's properties are not analogous to those of leaf film and the stopping distances generated under test conditions using detergent may be unrepresentative. The actual conditions generated by this method may vary from test to test, depending on weather and environmental factors. There is also a limit as to how low a level of adhesion can be

generated using detergent (around 0.04), whereas adhesion levels of 0.02 and lower have been experienced on the national network. A Euronorm is currently being drafted which covers WSP equipment testing. This currently advocates the UIC approach involving live testing.

163 Failure to meet the WSPER® criteria does not automatically result in a WSP system failing the test, which then raises the issue as to when a system would be considered to have failed. The inclusion of maximum stopping distances within the appropriate RGS (paragraph 133) would help to regularise this situation. However, the development of such criteria would need to be accompanied by the development of a validated, reliable and repeatable test method for demonstrating compliance. This requirement means that live testing is unlikely to be adequate because of the difficulty of producing test conditions that will be the same from one test to the next. Simulation offers a repeatable test method against defined parameters.

164 A number of observations flow from a review of current practice for testing WSP systems:

- Simulation is a good method for providing consistent and repeatable test conditions, which are more difficult to create in a live environment. Their potential use should be recognised within the draft Euronorm on WSP testing. Simulators need to be properly validated before they can be used with confidence to predict the performance of WSP (and other) systems.
- There are no 'whole train' simulators currently available that have been validated to the level necessary to prove that they can accurately predict performance of modern multiple units. This means that there is no certainty that they provide an accurate estimate of the performance of the WSP systems they are testing (paragraph 153).
- The absence of pass and fail criteria for maximum stopping distances under sustained low adhesion conditions means that there is no way of assessing the acceptability of the stopping distance predicted by WSPER® (one of its key objectives) (paragraph 159).
- The adhesion profiles used within WSPER® are based on those that were present on the network in the early 1990s when a tribometer train was operated (paragraph 123). It is possible that measurements taken now would show different adhesion profiles. Simulation should be based on currently-prevailing conditions.
- The predictions of stopping distance provided by simulation tools are currently pessimistic because they only simulate the performance of a single vehicle (the longer the train, the shorter the stopping distance – all other variables being equal), they only take account of the effects of rail head conditioning on a single vehicle (not the whole train) and they do not take accounts of the effects of sanding (paragraph 153).

Key issues – testing of WSP systems

165 The analysis contained in paragraphs 153 to 164 has identified the following key issue:

- There is currently no validated model for testing WSP systems that can accurately predict the behaviour of a whole train and the effects of systems such as sanding on the overall stopping distance (paragraph 153).

Sanding

166 This section analyses sanding systems on trains operating over the national railway network and addresses the following issues:

- characteristics and distribution of sanding systems on modern fleets;
- the value of sanding in minimising the extent of overruns during low adhesion incidents;

- the impact of RGS in limiting the amount of sand that can be dispensed by modern units;
- the reasons why there are variations in the characteristics and operating parameters of sanding equipment provided on different fleets;
- sand usage.

167 Sanding equipment is provided on a significant proportion of modern rolling stock and has been mandatory on new rolling stock since 2003. Two basic types of sander are found on units operating over the national railway network. 'Automatic' sanders are fitted to the majority of modern trains. They are triggered by the WSP system without intervention from the driver. 'One-shot' sanding devices are fitted to some modern multiple units (e.g. classes 220 and 221). They are triggered, as required, by the driver.

168 Based on information supplied by the rolling stock leasing companies, of the vehicles operating during autumn 2005, 81.6% were marshalled into multiple units that were equipped with sanding for use in train braking. A further 4.1% in Classes 142-144 and Class 153 comprise units that are specifically barred by RGS from having sanding equipment because they do not have six axles behind the point at which sand must be delivered (paragraph 134).

169 This leaves 14.3% of vehicles permitted to carry sanding equipment that were not doing so in autumn 2005. Of the older fleets, those with the highest populations in this category were Classes 150, 156, 313 and 365. Most modern fleets were equipped with sanders, exceptions in autumn 2005 being Classes 357/0, 458 and 460. Since autumn 2005 further fleets have been equipped with sanders including classes 357/0 and 458. The percentage of vehicles operating on the network within units not equipped for sanding has now fallen to 9% (excluding those barred by current RGS).

170 Only 6.1% of vehicles operating on the national network are marshalled into trains with neither WSP for managing wheelslide during braking nor sanding and they are restricted to Classes 142-144 and Class 153 and some Class 150 and 156 units. The Class 142 was the worst performing DMU class for adhesion-related incidents during 2005 (paragraph 72).

171 Since the late 1990s, a significant influx of new rolling stock onto Britain's main line railway network has occurred, with four TOCs operating intensive services in the south east completely replacing their main line fleets. Considerable variation was apparent between the fleets of rolling stock that were delivered in that time, the key differences in autumn 2005 being summarised below:

- Some fleets had no sanding (Classes 357/0 and 458).
- Some fleets had sanding that was only operative when the driver selects full service (75% braking, equivalent to Step 3 braking on units not fitted with stepless brake controllers) or emergency braking and WSP is active (Classes 444 and 450).
- Some fleets had sanding that was operative when the driver selects Step 2 braking (and above) (Classes 357/2 and 377).
- Some fleets featured continuous sanding once the trigger threshold has been reached, providing WSP remains active and there is sand available to deliver (Classes 360 and 450).
- Some fleets imposed a time limit on sanding, e.g. 10 seconds (Classes 175 and 377), 30 seconds (Classes 321 and 322) and the 2005 modification to the Class 377 units allowed 60 seconds sanding.

- Some fleets were equipped with sanding equipment that can vary sanding rate with the speed of the train. The Class 465/466 units are equipped with variable rate sanders. They work on suburban services in SE London and Kent and are thus subject to frequent station stops. They were ranked 16th out of 32 multiple unit classes in autumn 2005 for low adhesion incidents. This represents a good performance under onerous conditions and indicates the value of higher rate sanding.

172 Tests undertaken by Siemens and SWT at Wildenrath in Germany during January and February 2006 confirm the value of sand in minimising the extension of stopping distances under low adhesion (~0.04) conditions:

- with no sanding employed, the stopping distance for a train travelling at 90 mph (144 km/h) was 1280 metres;
- with sanding active when the brake demand reached or exceeded 75% and train speed was above 19 mph (30 km/h), the stopping distance was 1140 metres (10.9% reduction);
- with sanding active when the brake demand reached or exceeded 40% and train speed was above 10 mph (16 km/h), the stopping distance was 940 metres (26.6% reduction).

173 These results also show that the earlier that sanding is initiated, the more effective it is.

174 The benefits of sanding under operational conditions were illustrated during autumn 2005 by c2c's experience. C2c operates trains between Fenchurch Street and Shoeburyness. In the main, their route follows the line of the River Thames. The service is operated by four-car Class 357 units which were ordered and delivered in two separate batches. The Class 357/0 units (forming 46 of the total fleet of 74 units) were delivered without sanders. The Class 357/2 units (commissioned in 2002, two years after the Class 357/0 units) comprising the remainder of the fleet were delivered with fixed rate sanders fitted.

175 Between 19 October and 26 November 2005, c2c had 26 adhesion-related overruns including one of over 1000 metres (three complete signal sections) at Westcliff on 6 November 2005. C2c's analysis indicated that of the 21 incidents involving four car units, 19 (90%) involved Class 357/0 units although they only comprised 62% of the fleet. In the light of this experience, c2c took the decision to issue amended operating instructions such that the non sander fitted units were operated in 8 or 12 car formation trains whenever possible and that four car trains were formed of sander fitted units. Following this change, the only adhesion-related incident that occurred was with an empty train on a heavily contaminated section of line that had not been subject to rail head treatment. It also involved a unit not fitted with sanding equipment.

176 Following the Lewes SPAD, Southern undertook a detailed analysis of data from the train's *Brake Control Unit* (BCU), which demonstrated that for the short time that sand was available (up to ten seconds), there was a discernible reduction in wheel slip and subsequent improvement in train braking. Duration of sanding is thus a key factor in helping to minimise extensions of overruns during periods of low adhesion. During autumn 2005, Southern Railway implemented a programme of increasing sanding duration on its Class 377 fleet from 10 seconds to 60 seconds. Of 26 incidents affecting Class 377 units in autumn 2005, only three involved units with 60 seconds sanding. Southern Railway has now increased the maximum sanding duration on the Class 377 units to 180 seconds. This is equivalent to the time taken to stop a train from 100 mph (160 km/h) using only step 1 braking and assumes that a braking rate no better than $0.3 m/s^2$ can be sustained throughout, even with the benefit of continuous sanding.

177 RGS GM/RT2461 imposes a requirement that the maximum permissible density of sand on which the last two axles of a train can come to a stand should not exceed 7.5 grammes/metre. This is done in order to avoid excessive sand being deposited on the railhead, which could lead to track circuits failing to detect the presence of a train (paragraph 136) and results in guidance that sanding rates should not exceed 2kg/minute. This is a specific risk with two car units, which only have six axles behind the point at which sand is delivered to clean the sand from the rail head. This also explains why units with less than six axles behind the point at which sand is delivered are currently excluded from having sanders fitted.

178 Some units dispense sand at the rate of 2kg/minute and employ a low speed cut off as well. The Class 444 and Class 450 units are an example, with the low speed cut off threshold in the vehicles as delivered being 18mph (30 km/h). This is likely to have contributed to some of the low speed station overruns that occurred with these fleets (e.g. the incident at Wanborough referred to in Figure 4). The low speed cut-off threshold has now been reduced to 10 mph (16 km/h). A low speed cut-off and restricted sanding rate are exercising control over the same hazard. If a low speed cut-off is provided, it might be possible to increase sanding rates.

179 When sand is dispensed at the rate of 2kg/minute at a speed of 90 mph (144 km/h), less than 1 gramme of sand is delivered for each metre length of rail. For each additional 10 mph (16 km/h) above the 10 mph (16 km/h) threshold, it would be possible to increase sanding rates by 2kg/minute, without the 7.5 grammes per metre length of track threshold being exceeded.

180 In August 2006, Southern Railway undertook low adhesion detergent tests between Dorking and Horsham to quantify the benefits of applying sand at a rate of 3kg/minute. Apart from demonstrating the value of sand per se (from a starting speed of 60 mph (96 km/h) stopping distances were improved by about 33% with sanders operational compared with no sand), the effect of increasing sanding rates to 3kg/minute was to reduce stopping distances by approximately 10% when compared with a sanding rate 2kg/minute under equivalent conditions. Southern has now converted its Class 377 fleet to sand at the higher rate.

181 Given that the sanding rate of 2kg/minute within RGS GM/RT2461 is based on the risk associated with two-car units consideration should be given to the circumstances under which relaxation of the requirements within the Group Standard might be appropriate. As indicated in paragraph 180, Southern has already made a successful case for sanding at a higher rate. The risk of failing to operate track circuits may be lower with units formed of three vehicles or more. Interfleet advises that they undertook some tests with a Class 508 EMU on Merseyrail where a much higher sanding rate than 2kg/minute was applied before problems with track circuit operation were encountered. The AWG has indicated that experience shows that some DC third rail EMUs operating on largely modern AC or jointless track circuits have little propensity for failures to activate track circuits, but disc-braked DMUs operating over DC track circuits have a much higher risk of so doing.

182 There has been inconsistency in provision of sanding equipment within the industry since the late 1990s (at the same time as some fleets were being retrospectively equipped with sanders, new units were being procured without sanding equipment). The RGS lays down base sanding requirements that can be safely applied to all units operating in any part of the network, but as these requirements have been in force for a number of years, there is a need to review them in the light of operating experience. This review might identify changes that could be made to the base requirements or circumstances under which the base requirements could be exceeded.

183 There is also a need to consider new approaches to sanding. Such approaches might include higher sanding rates for use in emergencies, sanding from units other than the leading unit and sanding in front of the leading wheel. Consideration should also be given to whether there are other means of mitigating the risk of trains failing to operate track circuits because of sand between the wheel and rail, including the possible use of contact-enhancing additives to sand dispensed by trains.

184 While sanding up to 2kg/minute is permissible under current standards, some units may, in practice, dispense sand at a significantly lower rate. The report into the adhesion-related SPAD at Esher makes reference to the maximum sanding rate on the unit involved being 1.32kg/minute. At a speed of 90 mph (144 km/h), this is equivalent to a dispensing rate of 0.5 grammes of sand per metre length of rail

185 Changes that TOCs have already made to sanding parameters (commencing sanding earlier, for a longer duration and at a faster rate) may affect sand consumption during autumn, as might changes that TOCs make in response to recommendations contained in this investigation report. It is important that maintenance procedures are reviewed and modified as necessary when changes are made to the operating parameters of key systems such as sanding.

186 Some modern multiple units provide a warning to the driver when sand levels are running low. For example, the Class 444 and 450 units are fitted with a low sand level warning light which is illuminated when there is 20% (approx 5 litres) or less sand remaining in any one sand box. Traincrew are instructed to report all instances of low sand warning light illumination to Fleet Control and Fleet Control will arrange for the unit's sand to be replenished at the first available opportunity.

187 The RAIB has considered whether sand dispensed when the train is travelling at high speed actually reaches the point where wheel meets rail. To investigate this further, SWT arranged for a video to be taken of the sanding nozzle and the wheel during the tests referred to in paragraph 172). The tests demonstrated that the sanding equipment on the Class 450 unit used in the test was effective in delivering sand to the point at which wheel meets rail. Even so, it is incumbent on the maintainers of rolling stock to ensure that the equipment is able to maintain this high level of performance and that the initial system set-up has not been disturbed by day-to-day operation.

Sanding – key issues

188 The analysis contained in paragraphs 167 to 187 has identified the following key issues:

- The application of sand improves the level of adhesion available to trains experiencing difficulties on contaminated rails (paragraph 172). However, not all units are equipped with the facility to lay sand (paragraph 168).
- The configuration of sanders on multiple units was not optimised in autumn 2005 to deal with the conditions encountered. Evidence from testing (paragraph 172) and operational experience (paragraph 176) indicates that benefit is gained from laying sand earlier and continuously while the WSP system is active.
- RGS GM/RT2461 contains base requirements for sanding but there is a need to consider whether those requirements should be updated in the light of operating experience and enhanced to provide guidance on the circumstances under which the base requirements can be exceeded (paragraph 182).
- There is a need for new approaches to sanding to be considered for possible inclusion within RGS GM/RT2461 (paragraph 183).

- Until the review of sanding parameters is complete, it is important that the maximum permitted sanding rates currently allowed by RGS (and existing derogations) are achieved by trains (paragraph 184).
- As changes already made by TOCs to sanding parameters in response to the events of autumn 2005 may lead to increased usage of sand during autumn 2006, it is important that maintenance procedures are reviewed and amended as necessary to address the effects of those changes (paragraph 185).
- Maintenance policy and practice for rolling stock sanding systems should include measures necessary to ensure that the equipment continues to deliver sand to the point where wheel meets rail (paragraph 187).

Braking

189 This section includes:

- a review of the key characteristics of braking systems currently available on multiple units operating over the national railway network in the context of their performance during low adhesion incidents;
- consideration of an alternative braking technology that does not rely on the wheel/rail interface to achieve retardation.

190 Modern trains are equipped with *friction braking* and *dynamic braking*. Disc brakes are employed for friction braking. Dynamic braking (braking of the train by turning the traction motors into generators) is employed in the initial stages of braking and the friction brake is blended in at a later stage to assist the dynamic brake when the brake effort required by the driver cannot be met by the dynamic brake alone. The dynamic brake helps to minimise use of friction braking, thereby decreasing wear and tear on discs and pads.

191 Under low adhesion conditions, the use of the dynamic brake may result in a greater probability of wheelslide occurring initially. This is because the required braking effort is achieved only by wheelsets on bogies equipped with traction motors. If a driver makes a Step 1 brake demand, this is equivalent to $0.3m/s^2$ or the need for a level of adhesion of 0.03 (see paragraph 9) at the interface between wheel and rail if brakes are applied on all wheels. If 50% of the wheelsets are equipped with traction motors and a driver makes a Step 1 brake application with retardation being achieved using the dynamic brake alone, this will result in the equivalent of a brake demand of $0.6m/s^2$ at each motored wheelset. An adhesion level of 0.06 would need to be available if wheelslide was to be avoided. In a situation where 0.04 adhesion was available at the wheel/rail interface, WSP activity would commence immediately if dynamic braking was being used but not if friction braking was effective on all wheels. Without dynamic braking, the train could decelerate at $0.3m/s^2$, but with dynamic braking it will initially decelerate at $0.2m/s^2$ (half of the 'available' $0.4m/s^2$).

192 TOCs have sought to alleviate this problem by configuring the braking system to ensure that if WSP activity occurs, the dynamic brake is inhibited within 3-5 seconds and friction braking is used exclusively. WSP will manage train braking during this period, thus ensuring that retardation is achieved, but at a slightly lower rate than would be the case if friction braking alone was employed.

193 The modification of braking systems to inhibit the dynamic brake when WSP is active has helped to reduce any potentially detrimental effects arising from its use under low adhesion conditions. Given the changes to braking technique implemented by some TOCs

for autumn 2006, which will involve the use of a higher brake step initially (paragraph 220), it will be important that inhibiting the dynamic brake when WSP becomes active is achieved reliably as the change makes it more likely that WSP activity will be experienced initially. Evidence from OTMR downloads can be used to establish whether the process of inhibiting the dynamic brake when low adhesion conditions occur is being achieved reliably. The OTMR downloads seen by the RAIB during the course of this investigation indicate that it is.

194 Disc brakes are provided on modern rolling stock whereas the stock they replaced was equipped with tread brakes. Some drivers have suggested that tread brakes are better than disc brakes at stopping trains in low adhesion conditions because they act directly on the wheel, having the effect of cleaning the wheels and improving adhesion accordingly. This may, in part, be attributable to the fact that tread-braked units achieve deceleration rates of $0.7m/s^2$, whereas modern disc braked rolling stock can achieve deceleration rates of $1.0m/s^2$ or greater. Thus the risk of exceeding available adhesion will be greater, although WSP should intervene to ensure that braking rate is matched to available adhesion. It may also be the case that drivers of modern trains are more aware of wheelslide as the display on the driver's desk will indicate if WSP activity is taking place.

195 The AWG low adhesion manual addresses the issue of tread braking and disc braking. Quoting work carried out by British Rail Research in which the relative performance of the two brake types was examined, the AWG Manual makes the following assertions (RAIB comments in brackets):

- Tread braked stock generally has lower operating speeds and lower braking rates than disc braked stock. This can help to create the impression that the brake itself is contributing to better performance.
- When rail conditions are able to support full braking demand, disc brakes are superior to tread brakes (this is borne out by drivers of modern rolling stock who agree that in dry conditions disc braking is more effective).
- When rail conditions are poor (i.e. in drizzle) a good WSP with disc brakes will stop the train in a comparable distance to a tread braked train (this runs counter to the evidence from drivers who have indicated that modern rolling stock was not as effective at stopping under drizzly conditions in autumn 2005 as the tread braked stock that it had replaced).
- When rail conditions are severe a good WSP system will stop the train in a comparable distance to a tread braked train (however, the incident at Lewes on 30 November 2005 described in the Part 2 report suggests that WSP alone is not sufficient when drizzle falls onto a contaminated rail) but will avoid damage to the wheels in so doing, whereas the tread-braked train is likely to suffer wheel damage.

196 Although there may be no evidence to prove that tread braking yields benefits in stopping performance under low adhesion conditions, one advantage of the cleaning effect on wheel treads is to improve electrical contact between the wheel and the rail. For this reason, auxiliary tread brakes (sometimes known as scrubber blocks) were fitted to some disc braked vehicles to aid track circuit operation by cleaning and roughening the wheel treads. There is insufficient evidence to judge whether vehicles equipped with auxiliary tread brakes are less likely to be involved in adhesion-related station overruns because the number of units so equipped is small.

197 One further issue associated with disc braking is the possibility that the lack of cleaning of the wheel surface results in contamination not being cleaned off train wheels, with the attendant hazard that it can be transported around and create adhesion difficulties when the train is required to slow. Currently, wheel swabbing is not systematically undertaken after serious adhesion-related incidents (it was not undertaken after the SPADs at Esher or Lewes) and there is no evidence to evaluate this phenomenon.

198 The friction and dynamic braking systems on rolling stock using the national railway network in Britain are dependent on the level of adhesion available at the interface between wheel and rail. In some European countries (such as Germany and the Netherlands), magnetic braking is employed as an additional means for stopping trains. Magnetic brakes may be used for stopping trains under normal conditions to provide shorter stopping distances with higher speed trains running on lines where signal spacing cannot be adjusted to accommodate higher speeds (and thus it is necessary to shorten stopping distances). They may also be used to minimise stopping distances in emergencies. Similar systems are employed on vehicles operating on some light rail systems in England. A short description of magnetic braking is included in Appendix D highlighting that some forms of magnetic brake require contact between the brake and the track (referred to as magnetic track brakes (MTB), while other forms of magnetic braking are achieved without contact.

199 Research recently conducted for the AWG[7] into the implications of adopting MTBs as a means of stopping trains in an emergency on the national railway network has demonstrated that although there are still some technical issues to be resolved, it is feasible to fit existing units with MTBs. The recommendations in that report include fitting MTBs to a small number of units in order to establish the technical implications and evaluate the costs and benefits.

200 The attraction of magnetic braking is that it offers a potential step change in emergency braking performance. Optimisation of WSP and sanding parameters are worthwhile initiatives and may yield significant benefits in reducing stopping distances. But the incidents at Esher and Lewes both demonstrated that in emergency situations, the length of overrun from a normal stopping point under low adhesion conditions can exceed 1000 metres. For those emergency situations, the ability to utilise a different form of braking (in conjunction with WSP and sanding) has the potential to achieve further significant reductions in stopping distances.

Braking – key issues

201 The analysis of braking systems in the context of low adhesion incidents contained in paragraphs 190 to 200 has revealed the following key issue:

- The experiences of autumn 2005 show that there is scope for further action to address the risk from the most severe adhesion-related incidents. Although the changes made by train operators to sanding and professional driving policies may yield benefits, it may be several years before a final judgement on their effectiveness can be made. In the meantime, there is a need to consider alternative systems that do not rely solely on the wheel/rail interface such as magnetic braking as a means for improving stopping performance in low adhesion conditions (paragraphs 198 - 200).

[7] Interfleet Technology. 'Outline feasibility of fitting magnetic track brakes to UK rolling stock', Report No. ITLR-T17544-001, Issue 1A, 3 April 2006

Summary – rolling stock

202 Paragraph 85 raises the issue of the apparent greater susceptibility of modern rolling stock to adhesion-related incidents based on evidence from recent autumns. There are a number of technical explanations for the apparent greater susceptibility of modern rolling stock to adhesion-related incidents and these have been identified in the summary of key points in the sections on RGS, WSP, sanding and braking. The configuration of sanding equipment can be resolved quickly, but issues such as achieving best use of WSP under sustained low adhesion conditions will require a programme of work to evaluate and resolve.

Operational and Management Factors

Introduction

203 This section considers operational and management factors that influenced adhesion performance during autumn 2005. It considers the following factors:

- procurement and approvals process for new rolling stock;
- TOCs understanding of new rolling stock;
- driving policy and practice;
- driver training and briefing.

Procurement and approvals process for new rolling stock

204 Paragraph 171 highlighted the significant variety in sanding parameters on fleets operating over the national railway network in recent years. Despite this variety, all of the fleets are, compliant with RGS GM/RT2461 (paragraph 134), evidence of the variations permitted by the RGS. It is also indicative of the flexibility in the provisions of the standard that was inherent at the time the fleets were being designed. When procuring new fleets, TOCs prepare a specification. The specification includes, inter alia, performance criteria. However, two recent specifications for new fleets did not contain any clauses on performance criteria for sanding. Decisions on the operating parameters of the equipment were taken by the manufacturers, influenced by the limited performance requirements contained within the RGS.

205 Following the events of autumn 2005, it is apparent that if some TOCs had been more involved in the specification of sanding parameters when new stock was being procured, not only would they have been more aware of the performance characteristics of the system, but they could also have influenced those characteristics and developed their professional driving policies to match the performance of the units (paragraph 216). When procuring new rolling stock, TOCs have general responsibilities under health & safety law to ensure the safety of those affected by their operation (staff, passengers and members of the public). One method of complying is to prepare a specification for new rolling stock and to participate in the development of the design to ensure that the operational risk is reduced to a level that is as low as reasonably practicable.

206 In practice, the input provided by TOCs to this process was inconsistent. A number of TOCs have stated to the RAIB that they now recognise the need for their input into the configuration and operation of sanding systems in the future, utilising the experience that they can bring to the subject. Reference has already been made in paragraph 182 to the need for the RGS on sanding to be reviewed and/or supplemented with guidance. Input from the TOCs to that process will help to ensure that recent experience is reflected in its provisions.

207 The RGS states certain minimum threshold conditions for sanding (e.g. sand must be dispensed in full service and emergency braking). Unless an alternative specification is provided by the TOC or owner of the rolling stock, there would be no reason for the manufacturer to provide sanding that was initiated at a lower brake step. Similarly, the RGS does not specify any requirements for duration of sanding. This has resulted in some manufacturers supplying units with sanding duration limited to 10 seconds. During the late 1990s, the concern to avoid excessive sand being deposited on the rail head (and avoid sand boxes being emptied in a single application) resulted in at least one manufacturer imposing a time limitation on sanding as one way of minimising the risk.

208 In the absence of additional requirements in a specification, a rolling stock manufacturer has only RGS for guidance. A manufacturer offering equipment which dispenses sand in full service and emergency braking only is compliant with RGS GM/RT2461. But there is nothing in RGS GM/RT2461 which prevents a manufacturer from equipping a train with a sander that is operative in Step 2 braking. The only way in which additional provision might be made is if the train owner or operator specified different sanding parameters or the manufacturer supplied them. In all cases, this would require agreement between all relevant parties regarding the value of so doing.

209 The approvals process for new rolling stock requires the use of a VAB to verify compliance with standards. VABs are accredited to perform this role. Given the flexibility of the RGS on sanding, the same VAB could review the design and performance of new fleets with significantly different sanding parameters and conclude that all of them were compliant. Under these circumstances, the VAB has no justification for raising an objection to the design or performance.

210 The same issue relates to stopping distances predicted by WSPER®. WSPER® is used to demonstrate that the standards for air consumption and no wheel lock-up have been met and also that the manufacturer has optimised the WSP equipment to the vehicle. However, it also estimates stopping distances for trains under low adhesion conditions. Paragraph 154 describes how performance criteria have been developed by AEAT and railway industry partners for stopping distances of trains under naturally occurring variable adhesion conditions. As these criteria are not contained within RGS, there is no basis for a VAB to challenge performance of WSP systems. One example was seen of a stopping distance for a new fleet of rolling stock that exceeded the criteria. AEAT argued that because the simulation produced pessimistic estimates of stopping distance (one vehicle only tested, no sanding assumed), the result was still acceptable. The VAB could raise no formal objection to this exceedence as in doing so they would have stepped outside their formal role of reviewing compliance against standards. But it would have been possible for them to comment on this issue, although they did not do so.

TOC understanding of new rolling stock

211 The events of autumn 2005 were affected by some TOCs having an incomplete understanding of the characteristics of their newly- delivered fleet. In one specific example, different views were held by members of the same department on the conditions under which sand was dispensed. In another case, a light on the driver's desk had been labelled 'sanding' and the company believed that when it was illuminated, it indicated that sand was being dispensed. In fact, when illuminated, it indicated that WSP was active; sand would only be dispensed if the appropriate brake step had been selected. In another case, there was confusion among drivers as to how long sanding would be available and whether placing the brake controller into the emergency position would result in sanding being stopped.

212 In the absence of a clear understanding on the part of some TOCs regarding key characteristics of their new rolling stock, it is inevitable that the briefing given to drivers would be affected. Drivers must know when sand is being dispensed during a low adhesion wheelslide incident because sand acts as an adhesion modifier. On all modern rolling stock, the effect of holding a train in the lowest brake step during a wheel slide incident will be that that sand is not dispensed, thereby lengthening the stopping distance of the train.

213 Of equal importance is a driver's understanding of time limits on sanding. If the duration of sanding is limited, drivers need to be able to make a judgement on the value of releasing the brake and reapplying it when the time limit has been reached, which would at least ensure that a second period of sanding becomes available.

Driving Policy and Practice

214 The professional driving polices of TOCs for autumn 2005 emphasised the need for drivers to respond quickly to situations where they may be required to stop their train by braking early but in a low brake step. Many TOCs have encouraged drivers to use brake steps 1 and 2 only during 'normal' driving, with brake step 3 being used as a 'last resort'. When TOCs review driver performance via OTMR downloads, significant use of step 3 braking could be seen as non-compliance with the TOC's professional driving policy.

215 For autumn 2005, the philosophy of 'light and early' was endorsed by most TOCs as appropriate for low adhesion conditions, together with a progressive move through the brake steps if more retardation was required. This technique was correctly used by the drivers involved in the Esher and Lewes SPADs; it can be seen from the OTMR downloads that each brake step was being held for a few seconds before a higher brake step was selected.

216 However, it is also the case that sand is only dispensed in higher brake steps (step 2 or step 3 depending on the fleet). Therefore, the justification for holding a train in a lower brake step when it is sliding is not apparent. A further advantage of moving to a higher brake step quickly is that should the train encounter an area of better adhesion, it will slow more rapidly than would be the case if it were held in a lower brake step. This may help to compensate for the early stages of braking when the train was sliding.

217 Merseyrail has experienced a significant improvement in adhesion performance between autumn 2000 and autumn 2005, in contrast to the deterioration experienced by some other TOCs. In autumn 2000, Merseyrail had 67 adhesion-related station overruns and SPAD incidents. This represented 21.9% of the 306 events recorded that year. In autumn 2005, the worst for adhesion-related in recent history, Merseyrail experienced no station overruns or SPADs attributable to poor adhesion.

218 Merseyrail's driving policy for low adhesion conditions is consistent with the 'light and early' approach adopted by other TOCs. However, they advise their drivers that if they experience adhesion difficulties when step 1 braking is selected, they should immediately place the controller into brake step 3. This ensures that sand is dispensed and that the brakes can take advantage of any improvements in adhesion that become available either through WSP activity, sanding or better rail head conditions.

219 Not all of the dramatic improvement in adhesion performance at Merseyrail can be attributed to the different driving policy (their units have been equipped with sanders since 2000 and they work closely with Network Rail who have made improvements to rail head treatment over the Merseyrail network in the last few years), but the driving policy may have made a contribution.

220 In the first few months of 2006, South Eastern Trains, Southern Railway and SWT worked closely together on methods for improving performance during low adhesion conditions. The three TOCs have now decided that during the autumn low adhesion period, they will adopt a policy of using brake step 2 (40% braking for fleets with stepless brake controllers) rather than brake step 1 initially (a fundamental departure from previous practice). This policy has the advantage that it will allow sand to be dispensed immediately if WSP becomes active on the initial brake application. This policy may be appropriate for adoption by all operators with modern WSP systems.

221 Drivers have expressed the view that the braking characteristics of modern rolling stock were superior to those of older stock during dry conditions. Although the braking policy of TOCs was 'light and early', the possibility that some drivers had become so accustomed to the superior braking performance of modern units during the summer that they were braking much later during autumn was considered. Comparing autumn 2004 and autumn 2005, adhesion-related station overruns increased by more than 150%, but adhesion related SPADs increased by less than 30% possibly indicating a greater reliance by drivers on the capability of the brakes when approaching stations.

222 RAIB reviewed downloads from OTMR equipment to establish whether drivers were complying with the 'light and early' policy. The downloads showed that most, but not all, drivers complied.

223 There is insufficient evidence to estimate the extent of the impact of driving practice on the number of station overruns in autumn 2005, but it is possible that it may have made a contribution.

Driver training and briefing

224 Driver training and briefing practices were described in paragraphs 41 and 42. During the period 2000-2005, a number of TOCs replaced a significant part of their fleet with modern stock. In some cases, this led to a 'cascade' process whereby rolling stock displaced by the introduction of new rolling stock in turn displaced other stock within the same TOC's operation. The net effect of this was to expose a high proportion of drivers within the TOC concerned to rolling stock they had not operated before, with the attendant need for each driver to become accustomed to its characteristics.

225 However, there is no evidence that this was a specific causal or contributory factor to the high number of station overruns in autumn 2005. The introduction of new fleets was complete or well advanced (depending on the TOC) by 2004 and had this been a significant issue, the expectation might have been that performance in 2004 would have been poor, but this was not the case. The issue of driver experience was examined by the AWG in their report into the events of autumn 2005 and they concluded that there was no evidence that driver inexperience had contributed to poor performance in 2005.

Other factors

Operational and Management Factors – Key Issues

226 The analysis contained in paragraphs 204 to 225 has highlighted the following key issues:

- Some train operators had little involvement with the specification of sanding parameters on new rolling stock and this contributed to their variability and suboptimal performance during autumn 2005 (paragraph 204).

- The extensive introduction of new rolling stock and the TOCs' understanding of its characteristics affected the way in which drivers were briefed about handling trains in low adhesion conditions. The professional driving policies employed by TOCs for low adhesion conditions during autumn 2005 were, in some cases, imperfectly aligned with the braking and sanding characteristics of the rolling stock (paragraphs 215 and 216). There is evidence that a strategy of moving to a higher braking step if adhesion problems are encountered is a better way of responding to low adhesion conditions (paragraphs 216-220).

Other factors for consideration

Low adhesion incident investigation

227 There were 331 station overrun and SPAD incidents reported in autumn 2005 that included initial information from Network Rail staff attending on site regarding the presence or otherwise of contaminants. Contamination was observed in 181 (55%) of cases. While this may seem to indicate that contamination is not present in 45% of the incidents recorded, in practice, it points to inconsistency in the way that information is captured after an adhesion-related incident.

228 Currently, there is no standard response to serious incidents caused by low adhesion. A Network Rail MOM attends adhesion-related station overruns and decides on the basis of a visual inspection whether contamination is present. If it is seen to be present, rail head swabs are taken. Rail head swabbing is always undertaken when adhesion-related SPADs have occurred, but there is inconsistency over how many swabs are taken, where they are taken and when they are taken. In the case of the Esher SPAD, some railhead swabbing was not undertaken until 6 hours after the event. Given the transient nature of low adhesion conditions and the fact that many trains had passed over the affected line in the interim, swabbing at this stage would not have yielded meaningful results.

229 There is limited value to be obtained from swabbing, but this is not to say that it is valueless. Occasionally, it can help to identify the source of contamination, distinguishing for example between hydrocarbons such as diesel and mineral oils. But the current swabbing regime relies on a visual examination as an input to the decision on whether to swab or not and this means that if invisible contamination is present, the rail head will not be swabbed even though it is possible that analysis might have been able to reveal something significant.

230 Wheel swabbing is rarely undertaken after adhesion-related incidents. A possible source of evidence is therefore being overlooked. It is unusual to find any reference in industry investigation reports to even a visual inspection of wheels for contamination. In Network Rail's Sussex Route, their MOMs will not undertake wheel swabbing because of concerns over residual current being present. No specific constraint of this nature has been advised by TOCs.

231 When swabbing is undertaken, the results are sent to Scientifics Ltd in Derby for analysis. The process is described in paragraph 48. Although this can help to identify the source of the contamination, there is no way of linking the contamination found with the level of adhesion experienced. Furthermore, as the swabbing test involves the application of distilled water to a pad in order to facilitate removal of solid contaminants, it cannot shed any light on whether the effect of the contamination present had been exacerbated by moisture, such as drizzle.

232 Overall, there is no reliable method for measuring adhesion at sites where incidents have occurred. Data on WSP activity and braking from the OTMR yield valuable information on train speed and stopping distance that enables a train's braking rate to be calculated. However, the OTMR can only give an average value for the level of adhesion rather than an absolute value. In addition, if sanders are working properly the actual level of adhesion available to the train will have improved (use of OTMR data may overestimate the base level of adhesion present). Data from the BCU provides more information about the braking performance of the train including brake cylinder pressures on individual wheels.

233 Procedures governing post-incident investigation of adhesion-related incidents in 2005 were insufficiently detailed to permit a consistent approach to the gathering and processing of information. Procedures did not address the following factors:

- the circumstances under which it is mandatory to gather data;
- what data will be gathered;
- who will be responsible for gathering the data;
- how the data will be gathered, including any conditions to be imposed on train operations over the affected line until the required data has been gathered;
- how data will be processed and by whom;
- how the results will be reported and by whom;
- how the report will be disseminated, to whom and the nature of the follow-up required,
- responsibilities with regard to reviewing the reports and taking appropriate actions.

234 Although there needs to be more thorough investigation of serious adhesion-related incidents, there would be major implications if operations were suspended every time that an overrun occurs. The decision on the depth to which an investigation into an overrun is undertaken should be based on the circumstances and the potential for harm. Any overrun which under slightly different circumstances could have resulted in an accident and overruns of a significant length should be subject to a full investigation. In autumn 2005, there were six station overruns of 1000 metres or more and a further 18 station overruns of 250-999 metres. An investigation regime encompassing all of these incidents would yield very useful data to help in the industry's understanding of adhesion-related events, without having a major impact on operational performance.

Low adhesion data capture

235 Modern trains gather information that is potentially useful in providing key data regarding adhesion-related incidents. Data available from OTMRs, BCUs and Traction Control Units can provide valuable information to enable the actual level of adhesion experienced by the train (as modified by WSP and sanding) to be calculated as well as providing information on how the train's systems performed during the incident. The data can also help to establish the impact of WSP and sanding systems, as was illustrated in the work undertaken by Southern Railway after the Lewes SPAD (see the Part 2 report).

236 Modern rolling stock has the potential to provide current information to the Infrastructure Manager and TOCs about the adhesion status of the railway. The Low Adhesion Warning System (LAWS) is fitted to a small number of units operating over parts of the national railway network (e.g. Central Trains has the equipment fitted to three of its Class 323 units). LAWS can provide current data on adhesion and help to inform rail head treatment policy in the future.

237 If the data gathered by modern trains can be processed and fed back in real time, the enhancement in knowledge for operators is potentially worthwhile. It would enable Network Rail to warn drivers about adhesion problems in specific areas and enable drivers to control their trains accordingly. It would enable rapid deployment of staff or equipment to implement measures to improve adhesion and could also be used to inform the process of determining rail head treatment policy for each of the Network Rail routes. It may be that LAWS can form the basis of such a system, but this remains to be evaluated.

238 A further benefit may be that data from modern trains could be used to provide input to WSP simulator tools (paragraph 164). Data used in simulations must reflect current conditions and there may have been changes from the previously collected data due to the introduction of modern disc braked rolling stock and differences in rail head treatment practice. The data recording capability of modern trains means that it is now possible to quantify levels of adhesion experienced on a daily basis over virtually the whole network.

239 During the investigation, reference was made to the data contained in a recent study into low adhesion conditions that was carried out for the European Rail Traffic Management System (ERTMS) development project. This data was also based on adhesion profiles from the tests undertaken during the 1990s, which may not reflect current conditions.

Conclusions

240 There is no single immediate cause of the high number of adhesion-related SPAD and station overrun incidents that occurred in autumn 2005. There are, however, a significant number of causal and contributory factors.

Causal Factors

241 Significant lengths of low adhesion were experienced on a number of occasions during autumn 2005 and it is possible that they are now occurring more frequently than has been previously thought to be the case (paragraph 123). See Recommendation 18.

242 The approach to the identification of high-risk low adhesion areas on the national rail network was biased towards historical data and recent performance rather than risk arising from the configuration of the infrastructure (e.g. layout of junctions and level crossings) (paragraph 97). See Recommendation 4.

243 Uncertainty over the optimum method for treating the rail head resulted in different methods of treatment being employed across the network. There is contradictory evidence from autumn 2005 with regard to the optimum strategy for railhead treatment (paragraphs 105-109) and further changes made for autumn 2006 need to be validated in terms of their effectiveness (paragraph 112). See Recommendation 5.

244 There was variable performance in the prediction of low adhesion conditions. The overall accuracy of rail head condition prediction using the ADAS system throughout autumn 2005 was unreliable (paragraphs 113 to 115). See Recommendation 6.

245 The application of sand improves the level of adhesion available to trains experiencing difficulties on contaminated rails (paragraph 172). However, not all multiple units are equipped with the facility to lay sand (paragraph 168). See Recommendation 9.

246 Some multiple units are specifically barred from being able to lay sand (paragraph 135). See Recommendation 11.

247 The configuration of sanders on multiple units was not optimised in autumn 2005 to deal with the conditions encountered. Evidence from testing and operational experience indicates that benefit is gained from laying sand earlier (paragraph 172) and continuously while the WSP system is active (paragraphs 172 to 176). See Recommendation 1.

248 RGS GM/RT2461 contains base requirements for sanding but there is a need to consider whether they should be updated in the light of operating experience and enhanced to provide guidance on the circumstances under which the base requirements can be exceeded (paragraph 182) See Recommendation 11.

249 Some train operators had little involvement with the specification of sanding parameters on new rolling stock and this contributed to their variability and suboptimal performance during autumn 2005 (paragraph 204) See Recommendation 13.

250 The extensive introduction of new rolling stock and the TOCs' understanding of its characteristics affected the way in which drivers were briefed about handling trains in low adhesion conditions. The professional driving policies employed by TOCs for low adhesion conditions during autumn 2005 were, in some cases, imperfectly aligned with the braking and sanding characteristics of the rolling stock (paragraphs 215 and 216). There is evidence that a strategy of moving to a higher braking step if adhesion problems are encountered is a better way of responding to low adhesion conditions (paragraphs 216-220). See Recommendation 2.

Contributory Factors

251 There are no criteria within RGS on maximum braking distances under low adhesion conditions (paragraph 133). See Recommendation 10.

Other Issues

252 Further research is required into the mechanisms that create severe low adhesion conditions (including the phenomenon of invisible contamination) and how it can be treated (paragraph 124). See Recommendation 8.

253 As changes already made by TOCs to sanding parameters in response to the events of autumn 2005 may lead to increased usage of sand during autumn 2006, it is important that maintenance procedures are reviewed and amended as necessary to address the effects of those changes (paragraph 185). See Recommendation 1.

254 Maintenance policy and practice for rolling stock sanding systems should include measures necessary to ensure that the equipment continues to deliver sand to the point where wheel meets rail (paragraph 187).

255 There is a need for new approaches to sanding to be considered for possible inclusion within RGS GM/RT2461 (paragraph 183). See recommendation 12.

256 It is important that maximum permitted sanding rates are achieved by trains (paragraph 184). See Recommendation 14.

257 Although the17-20% slip' parameter for WSP systems is well suited to the reliable stopping of trains in most low adhesion conditions, further consideration of higher and lower levels of slip will help to determine whether an alternative approach is better for severe low adhesion conditions (paragraphs 147-150). See Recommendation 16.

258 Longer trains are more likely to be able to benefit from rail head conditioning and thereby reduce stopping distances (paragraph 141). See Recommendation 3.

259 There is currently no validated model for testing WSP systems that can accurately predict the behaviour of a whole train and the effects of systems such as sanding on the overall stopping distance). Simulation offers advantages over live testing and there is a need for the draft Euronorm on WSP testing to recognise the role that simulation can play (paragraph 164). See Recommendation 15.

260 The experiences of autumn 2005 show that there is scope for further action to address the risk from the most severe adhesion-related incidents. Although the changes made by train operators to sanding and professional driving policies may yield benefits, it may be several years before a final judgement on their effectiveness can be made. In the meantime, there is a need to consider alternative systems that do not rely solely on the wheel/rail interface such as magnetic braking as a means for improving stopping performance in low adhesion conditions (paragraphs 198 - 200). See Recommendation 17.

261 Incident investigation is not performed in a consistent or systematic manner, with the result that potential intelligence on adhesion-related incidents is lost (paragraph 233 and 234). See Recommendation 7.

262 Accurate information about real levels of adhesion is increasingly available from modern trains, but is not being exploited to its full potential by the railway industry (paragraphs 235-238). Possible uses of such data include providing real time information to drivers regarding low adhesion conditions and providing data to enable more accurate data regarding rail head conditions to be used in simulation tools for WSP systems. See Recommendation 18.

Observations

263 A recent study into low adhesion conditions was carried out for the European Rail Traffic Management System (ERTMS) development project (paragraph 239). This study refers to data obtained by the tribometer train in the 1990s. This data has not been updated since. See Recommendation 19.

Actions already taken or in progress

264 The industry, through the auspices of the National Task Force commissioned the AWG to undertake an investigation into the events of autumn 2005. The AWG issued its report in April 2006 (known as 'the Goff report'), containing a series of recommendations that are designed to assist in the improvement of performance in autumn 2006. The industry is responding to the recommendations from AWG.

265 Network Rail appointed an individual to assist with the coordination of the industry's response to the recommendations from all investigations into the events of autumn 2005. Appendix E contains a comparison between the recommendations of the Goff report and the recommendations from this RAIB investigation.

266 Individual TOCs (e.g. First ScotRail, First Great Western, c2c) have undertaken reviews into their own performance during autumn 2005 and have identified and implemented their own action plans for autumn 2006. Network Rail and First Group also conducted a joint review of experiences in autumn 2005.

267 Individual TOCs have provided sanding on units that were not equipped last autumn, e.g. c2c on the Class 357/0 units, First ScotRail on the Class 320 units and SWT on the Class 458 units.

268 Individual TOCs have changed the sanding parameters on their fleets to enable initiation of sanding in brake step 2 (or equivalent), e.g. SWT on classes 444 and 450, First ScotRail on Classes 170 and 318.

269 Individual TOCs (e.g. SWT, Southern, Souteastern) have made a fundamental change to the braking policy that will be briefed to drivers. Their drivers will now be instructed to make their initial braking action during autumn in step 2 (40%) rather than step 1.

270 Individual TOCs have undertaken full scale testing of their rolling stock under low adhesion conditions to test various braking, WSP and sanding parameters. SWT conducted trials at Wildenrath in January/February 2006 and Southern Railway undertook tests in August 2006 between Dorking and Horsham. As a result of these tests, changes have been made to sanding parameters on some fleets, for example:

- Southern Railway's Class 377 units and Southeastern's Class 375 units, having initially been converted from 10 seconds to 60 seconds sanding, have now been converted again to permit 180 seconds sanding;
- SWT has converted its Desiro fleet to permit sanding at 40% braking and above, as compared with 75% which applied last autumn;
- Southern Railway and Southeastern have converted their stock to dispense sand at a rate of 3kg/minute, as compared with a rate of 2kg/minute, which applied last autumn.

271 Network Rail has conducted further trials of water jetting and Sandite and, as a result of these trials, will dispense Sandite from their MPV fleet at a higher speed of 40 mph (65 km/h), using a lower concentration of gel. Network Rail has also invested in more than 130 new Traction Gel Applicators for autumn 2005.

272 Network Rail in conjunction with Southern has implemented a programme of trials between Dorking and Horsham during autumn 2006 to assess different rail head treatment strategies. The advantage in using Network Rail infrastructure (as opposed to preserved railways, which have been used for such tests in the past) is that evaluation of effectiveness can be achieved with trains operating at higher (and therefore more realistic) speeds.

273 Network Rail (Wessex route) and SWT have developed a risk-based approach to identifying sites for rail head treatment (or enhanced rail head treatment), that takes account of the consequences of low adhesion incidents at specific locations such as junctions and level crossings as well as their probability. It has been implemented in time to inform rail treatment policy in Wessex, Sussex and Kent routes during autumn 2006 and will be used to inform policy nationally during autumn 2007.

274 Network Rail has worked with ADAS to improve the accuracy of its leaf-fall prediction model. New leaf fall areas have been created to align with Kent, Sussex and Wessex routes and a new area created for the Welsh valleys.

275 Network Rail is funding the trial of a high resolution leaf fall model for the London to Brighton route that will consider tree type, tree density and local topography to a spatial resolution of ¼ mile (400 metres). The accuracy and benefit of the model will be assessed during autumn 2006.

276 Trials are taking place on the Chiltern lines during autumn 2006 of a system that permits local monitoring of rail head conditions as a means of detecting changes that are specific to small areas and alerting Network Rail to specific problem areas that might otherwise go undetected.

277 ATOC has issued a guidance note on the investigation of station overrun and 'failed to call' incidents. Network Rail is aligning its procedures with this guidance note. The guidance indicates that all such incidents should be investigated and that steps such as obtaining BCU downloads can be taken, depending on the seriousness of the incident (paragraph 234).

278 Network Rail is equipping its MOMs' vehicles with an eddy current measuring device to allow immediate measurement of the thickness of leaf fall contamination following an incident.

279 Some TOCs are operating longer train formations where their own analysis shows that it is a reasonably practicable response to the risk associated with low adhesion conditions.

280 Network Rail at route level and individual TOCs have been working together to agree aspects of the autumn adhesion strategy, including locations of static equipment and a vegetation control plan.

Recommendations

281 The RAIB sent the recommendations 1-7 to the railway industry on 6 July 2006 to enable relevant parties to consider their contents and take action that they considered to be appropriate for autumn 2006. Some modification has been made to the wording of recommendations 2, 4, 6 and 7 to take account of action taken in the interim, clarify intent or facilitate the logical grouping of related issues.

282 The recommendations affect the railway as a system and many parties within the railway industry. The RAIB considers that:

- Network Rail and train operators should coordinate their activities with each other and with parts of the railway industry affected by the recommendations to ensure the optimum response;
- where it has been recommended that the implications of changes are assessed and implemented if appropriate, the assessment should consider the effect on systems and interfaces;
- where recommendations affect subjects that are currently addressed by existing or emerging TSIs and Euronorms, the findings from work performed in response to the recommendation should be fed into the appropriate European drafting committees.

283 The following safety recommendations are made[8].

Short Term

1. Train operators to:

   - make modifications to multiple units already fitted with sanding equipment to permit application of sand in brake step 2 and above (or the equivalent of brake step 2 and above on multiple units fitted with step-less brake controllers) for the duration of the period when the WSP system is active on the leading vehicle (paragraph 247);
   - adjust, as appropriate, rolling stock maintenance activities during the autumn low adhesion period to include enhanced monitoring of sand hoppers to ensure that sand is always available (paragraph 253);
   - review their maintenance polices and practices for sanding systems to check that they are targeted at ensuring that the system continues to deliver sand to the point where wheel meets rail (paragraph 254).

continued

[8] Responsibilities in respect of these recommendations are set out in the Railways (Accident Investigation and Reporting) Regulations 2005 and the accompanying guidance notes, which can be found on RAIB's web site at www.raib.gov.uk

2. Train operators to:

   - Modify as appropriate their instructions to drivers regarding the braking of trains equipped with a WSP system in low adhesion conditions to ensure that if the expected level of retardation is not achieved during the initial stage of braking, the optimum position of the brake controller is immediately selected to maximise braking efficiency. This may involve selecting a full service brake application or, where appropriate, an emergency brake application.
   - Brief any revised instructions to drivers (paragraph 250).

3. Train operators of multiple units operating in single unit formations to consider increasing the length of train consists during the autumn low adhesion season where reasonably practicable, e.g.:

   - where rolling stock is available;
   - where platforms can accommodate longer trains;
   - where, based on the train operator's review of low adhesion events and knowledge of problem areas for adhesion, there is a demonstrable benefit in so doing on specific routes and/or at specific times of day (paragraph 258).

4. Network Rail to develop and implement a risk-based strategy for rail head treatment and vegetation control in consultation with train operators. The strategy should be based on a review of recent data and take particular account of locations such as the approaches to junctions and level crossings where the consequences of an overrun could be severe. At high risk locations such as junctions, level crossings and steep gradients, consideration should be given to one or more of the following solutions:

   - the targeted application of Sandite;
   - application of Sandite using strategically placed fixed applicators;
   - temporary restrictions in operational use (e.g. avoiding the use of a junction);
   - temporary modification of signalling controls to extend effective overlaps beyond signals;
   - instructions to selected trains to perform running brake tests in order to assess the state of adhesion;
   - other effective measures defined by parties involved in managing the risk from low adhesion (paragraph 242).

5. Network Rail to:

   - plan and execute trials in conjunction with train operators to validate changes made to rail head treatment for autumn 2006 and assess potential adjustments for autumn 2007 (paragraph 243);
   - develop a strategy for rail head treatment in consultation with TOCs, based on the outcome of the trials (paragraph 243).

continued

6. Network Rail to conduct a review with ADAS to determine the scope for improving the accuracy of low adhesion prediction (paragraph 244).

7. Network Rail and train operators to develop a joint strategy for investigating adhesion related overrun and SPAD incidents that addresses:

   - Which low adhesion incidents are investigated;
     - criteria for undertaking an investigation (e.g. length of overrun, potential severity of outcome);
     - whether different levels of investigation are appropriate and if so, the criteria that apply to each one.
   - What data is gathered, when, how and by whom;
     - justification for gathering each item of data;
     - when wheel swabbing is appropriate and clear guidance on the extent and number of rail swabs to be undertaken;
     - train data recorders;
     - brake Control Unit;
     - traction Control Unit;
     - Network Rail and TOC staff responsibilities.
   - Whether enhancements can be made to existing swabbing techniques to improve the value gained from swabbing;
   - Management of investigations;
   - Use of alternative approaches or technology to estimate levels of contamination and/or adhesion available (paragraph 261).

Medium/Long Term

8. RSSB to extend research and testing into how severe low adhesion conditions occur with particular reference to the phenomenon of micro layers of contamination on rail surfaces, invisible to the eye. The research will seek to establish the nature of the contaminant, how it reaches the rail and bonds with it, the circumstances under which the contaminant poses a particular threat to train braking (e.g. the factors that exacerbate its impact), the factors that determine how long it endures, possible methods for identifying its presence and methods for preventing its formation and dispersing it (paragraph 252).

9. Train operators to fit automatic sanding equipment to those multiple units of five cars or less that are not currently so equipped, unless they are specifically excluded from doing so by GM/RT2461 (paragraph 245).

continued

10. RSSB to lead research into ways of deriving quantitative criteria for braking performance under low adhesion conditions and the implications of each identified approach (including the potential impact on railway infrastructure). The research should include a consideration of the levels of adhesion against which performance (e.g. stopping distances or deceleration rates) should be demonstrated (paragraph 251). The implications of adopting the approach proposed in the draft second issue of the high speed rolling stock TSI should be considered. The results from the research should be incorporated into the relevant RGS as appropriate and disseminated to those who are revising the high-speed rolling stock TSI.

11. RSSB to review the relevance of existing sanding parameters within GM/RT 2461 (paragraph 248) and amend, enhance or supplement them with additional guidance where appropriate. The review is to encompass:

    - implications (cost, benefits and disbenefits) of increasing the guide value of 2kg/minute for maximum sanding rate (taking account of the trials undertaken during August 2006 by Southern Railway);
    - the current sanding initiation threshold (full service and emergency braking) and the effect of reducing it to Step 1 or equivalent value for trains equipped with stepless brake controllers;
    - the need for criteria covering minimum sanding duration;
    - the need for criteria on sanding at low speeds including the implications of permitting sanding until the train has come to a stand;
    - identification of ways in which currently excluded vehicles (e.g. Classes 142-144, 153) can be equipped with sanders (paragraph 246).

12. RSSB to carry out research in conjunction with Network Rail and train operators into the implications, (cost, benefits and disbenefits) of:

    - adopting enhanced sanding rates under emergency conditions above a defined speed threshold (either activated manually by the driver or automatically activated by the placing of the brake controller into the emergency position when WSP is active);
    - allowing leading wheel sanding for high speed emergency braking;
    - permitting units other than the leading unit to dispense sand under emergency conditions;
    - methods of avoiding the problem of excessive sand causing failures to operate track circuits (e.g. use of different materials or additives) (paragraph 255).

13. Train operators to ensure that until RGS GM/RT2461 has been reissued, clauses on sanding are contained within specifications for new rolling stock. TOCS should specify, as a minimum, the requirement for continuous sanding while WSP is active in Brake Step 2 (or equivalent for trains equipped with stepless brake controllers) and above and a sanding rate of 2kg/minute (paragraph 249).

continued

14. Train operators to check the sand dispensing rate of each train within their fleets and ensure that it is set to the RGS GM/RT2461 guidance value of 2kg/minute except where a higher value has been permitted (paragraph 256).

15. RSSB to establish a project to:

    - Measure the accuracy of existing WSP simulation rigs that could be used to support rolling stock approvals. This validation should include reference to records obtained from train data recorders following actual incidents and full-scale testing as appropriate. The latter should include a direct comparison between UIC detergent test data and a simulation of the same (paragraph 259).

    - Examine the feasibility of extending the capability of an existing WSP simulation tool in order to predict more accurately the behaviour of an entire train in low adhesion conditions (e.g. allowing for rail head conditioning, the effect of sanding and more than one vehicle) (paragraph 259).

    The results from the project should be used to inform the developing Euronorm on WSP equipment testing (paragraph 259)

16. Subject to the successful development of the simulation tool described in Recommendation 15, RSSB to undertake a programme of modelling to evaluate the impact of different control strategies for minimising stopping distances under various low adhesion conditions. The simulation should specifically address potential alternative strategies for extreme circumstances including:

    - changing WSP control algorithms for the level of slip permitted from the current value of 17-20%;

    - permitting different levels of slip on wheels on the same train to optimise overall braking during low adhesion conditions.

    All the simulations should be designed to evaluate the effect of different strategies on braking performance and rail head conditioning and should include simulations with sanding operative (paragraph 257). The results from the programme should be shared with those responsible for drafting relevant high-speed and conventional TSIs for possible inclusion in new or revised versions of those documents.

17. RSSB to initiate a project to evaluate the costs and benefits of equipping multiple units operating over the British mainline network with magnetic track brakes for use in emergencies under low adhesion conditions. The project will:

    - Address and resolve the outstanding issues identified in Interfleet report ITLR-T17544-001.

    - Subject to successful resolution of outstanding issues, specify and procure magnetic track brake (MTB) equipment and fit it to a small number of units. The units chosen should represent different traction types with different operating regimes and operate in different geographical areas.

continued

- Develop and implement trials of these units, incorporating in-service experience and specific comparative tests with a similar unit not equipped with MTB.

The project will aim to determine whether MTBs are a cost effective solution for new-build rolling stock and/or retrofitting to existing rolling stock (paragraph 260).

18. RSSB to establish a study into the potential uses of systems on modern rolling stock to:

    - automatically sample adhesion conditions, e.g. by the controlled braking/release of a single wheel-set on service trains (other than during train braking) (paragraph 235);
    - establish the profile, nature and distribution of low adhesion conditions on the national rail network currently and provide input to WSP simulation packages (paragraph 241);
    - improve intelligence about adhesion conditions in real time, e.g. use of wireless data transmission to feed details of low adhesion conditions encountered during braking to a monitoring system. (paragraph 262).

    The study should take into account operating experience with the Low Adhesion Warning System (LAWS) and consider the lessons learnt in relation to the development of a network wide solution for monitoring low adhesion conditions. The study should be developed in the context of the work currently being undertaken by RSSB in research project T540, 'Scoping and Development of the Adhesion Management System'. The output from this study must include consideration of how the information can be used by the railway industry including the need for signallers and drivers to be made aware of low adhesion conditions in real time.

19. Network Rail to review ERTMS low adhesion assumptions in the light of the findings of this report and consider whether any changes are needed to ERTMS design or operating parameters in the light of the review (paragraph 263).

Appendices

Glossary of abbreviations and acronyms — Appendix A

AEAT	AEA Technology
AHBC	Automatic Half Barrier Crossing
ATO	Automatic Train Operation
AWG	Adhesion Working Group
BCU	Brake Control Unit
DMU	Diesel Multiple Unit
EEC	European Economic Community
EMU	Electric Multiple Unit
ERTMS	European Rail Traffic Management System
LAWS	Low Adhesion Warning System
MOM	Mobile Operations Manager
MPV	Multi Purpose Vehicle
MTB	Magnetic Track Brakes
OTMR equipment	On Train Monitoring and Recording equipment
RAIB	Rail Accident Investigation Branch
RGS	Railway Group Standard
RSSB	Rail Safety & Standards Board
SMIS	Safety Management Information System
SPAD(s)	Signal(s) Passed At Danger
SWT	South West Trains
TEN	Trans European Network
TOC	Train Operating Company
TSI	Technical Specification for Interoperability
UIC	International Union of Railways
VAB	Vehicle Acceptance Body
WSP system	Wheelslide Prevention system
WSPER®	WSP Simulator Rig

ADAS Classification System	System developed by ADAS UK Ltd and used by Network Rail to classify the risk from leaf-fall on each day during the autumn for discrete geographical areas of the national railway network.
Adhesion Working	Cross-railway-industry focus group with the sole objective of researching and developing initiatives to combat the effects of low wheel/rail adhesion and promoting awareness of the low adhesion issue within the industry and its key stakeholders.
Automatic Train Operation (ATO) mode	A system of train control that involves communication between the train and track-based equipment to initiate acceleration, coasting and braking as appropriate and maintains safe separation between all trains operating on the route.
Blowdown valves (also known as dump valves)	Valves provided to regulate air pressure for the purposes of rapidly applying and releasing brakes during WSP activity.
Brake Control Unit	Interface between the driver's brake controller and the train brakes, WSP equipment and sanding, converting brake demands from the driver into brake cylinder pressures (via an analogue control unit). The BCU also contains a microprocessor which manages the brake blending process and logs any faults that have occurred within the braking, WSP and sanding systems.
Braking (step 1, step 2, step 3)	Different positions on the driver's brake controller representing progressively greater brake demands, e.g. brake step 1 is analogous to a retardation rate of $0.3m/s^2$, brake step 2 to a retardation rate of $0.6m/s^2$ and brake step 3 to a retardation rate of $0.9m/s^2$.
Company Procedure (Network Rail)	A document that provides details of the procedure to be followed by Network Rail staff in order to comply with the requirements of a Railway Group Standard.
Conditioning (the rail head)	The process by which a contaminated railhead may be cleaned by the friction caused by train wheels passing over.
Diesel Multiple Unit	A self-contained diesel-powered train comprising one or more vehicles that can be coupled to other compatible diesel multiple units to form longer trains.
Dynamic brake/braking	A brake which operates by using the traction motors as electrical generators to slow down a train.
Electric Multiple Unit	A self-contained train powered by electricity gathered from overhead line equipment or conductor rails comprising one or more vehicles that can be coupled to other compatible electric multiple units to form longer trains.
Friction brake	A brake which operates by using friction to slow down a train, e.g. tread brakes which involve a metal block making contact with the tread of the wheel or disc brakes which involve contact between a pad and a disc located on the axle.

International Union of Railways	An international railway union comprising various railway companies and administrations to agree common standards and practices.
Late notice arrangements	A means of providing train drivers with information of a short-term or emergency nature at the time they commence their driving shift.
Mobile Operations Manager	A member of Network Rail's staff whose duties include rapid deployment to incidents and accidents to assist in the process of restoring the railway to normal operations and investigating the cause of the incident/accident.
Multi-Purpose Vehicle	Two power units placed at either end of a fixed formation train conveying, for example, containers or tanks. For the purposes of railhead treatment in Sussex during autumn 2005, they conveyed two containers, one with water which is jetted at high pressure onto the rails to clean the railhead and one with Sandite which is applied to the rails to improve adhesion.
On Train Monitoring and Recording Equipment	An on-board computer that records the status of different items of equipment in real time and enables a plot of train performance and driver actions to be downloaded.
Professional driving policy	A policy prepared by TOCs that describes, inter alia, train driving practices that the company expects its drivers to adopt in order to ensure safe and efficient train operations.
Railway Group Standards	Mandatory technical or operational document which sets out what is required to meet system safety responsibilities on Network Rail's infrastructure.
Rail Safety & Standards Board	A body established on 1 April 2003 with the objective of coordinating the railway industry's work in achieving continuous improvement in the safety performance of the national rail network.
Rule Book	A book which incorporates most of the rules to be observed by general railway staff for the safe operation of the railway.
Safety Management Information System	A database maintained by the RSSB which includes details of incidents and accidents occurring on the national rail network.
Sandite	A suspension of sand and steel particles in a gel applied to the railhead by MPVs and Rail Head Treatment Trains during the autumn leaf-fall season to improve adhesion conditions for trains.
Sectional appendices	Network Rail document containing local rules and instructions and details of the railway for a given part of the network.
Stepless brake controller	A brake controller that allows the driver to make fine adjustments (from 1% to 100%) in the amount of braking demanded.
Technical Specifications for Interoperability	European legislation which mandates certain minimum common standards across the European Union to facilitate inter-working of trains between member countries.

Track circuit	An electrical device using rails in an electric circuit which detects the absence of trains on a defined section of line.
Train detection	A means for detecting the presence of a train on a specific part of a route. Track circuits are one means of train detection, as are axle counters.
Train path	The planned schedule over the network for a train
Train Operating	A company that is franchised to run train services over a designated area of the national rail network.
Trap points	A set of points designed to derail a train that has passed the protecting signal at danger rather than allowing it to proceed onto a running line where it could collide with another train.
Tribometer train	A train that with specialised equipment on board to measure the adhesion available between wheel and rail.
Vehicle Acceptance Body	An accredited body that, inter alia, reviews the design of new rolling stock and confirms that it complies with standards.
Wheelslide prevention system	A system which, when active during braking, identifies when train wheels have started to slide and releases and reapplies brakes to: ● optimise braking rate to the level of adhesion available; ● condition the rail head (see separate definition).
WSPER®	A simulator operated by AEA Technology which is used to test and optimise the performance of WSP systems.

Key standards current at the time — Appendix C

GE/RT8000	Rule Book
GE/RT8040	Low adhesion between the wheel and the rail – managing the risk
GM/RT2461	Sanding equipment fitted to multiple units and on-track machines
GM/RT2044	Braking system requirements and performance for multiple units
GM/RT2045	Braking principles for rail vehicles
GO/RT3252	Signals passed at danger

An overview of magnetic brakes[9] Appendix D

Magnetic brakes are used extensively on light rail systems but there are also significant uses of the technology in heavy rail applications and high speed operations in Europe. Magnetic brakes can be divided into two types, those that achieve retardation by physical contact between brake and rail (this type is used extensively in Germany and the Netherlands) and those that work without contact between brake and rail (this type is less widely used but is provided on the ICE3 high speed inter-city trains in Germany).

Magnetic track brakes using physical contact between brake and rail

There are two types of magnetic track brake (MTB) that work by establishing physical contact between the brake and the rail head, the difference being the use of either an electromagnet or a permanent magnet.

- The electromagnetic type uses an energised coil to create a magnetic attraction force to bring pole shoes into contact with the rail.
- The permanent magnet type uses electrical, hydraulic or pneumatic switching of the magnetic field to bring pole shoes into contact with the rail.

For main line applications, the MTB is normally suspended from the bogie frame, with the contacting shoes positioned 60-130mm above the rail. The frame that supports the magnet is held to the bogie frame by springs within the brake actuators. When the brake is demanded, the actuators lower the frame at the same time as the magnets are energised or switched, depending on magnet type.

The retardation achieved is dependent on the attraction strength of the magnet and the coefficient of friction between the contacting shoes and the rail head. The coefficient of friction is determined by a number of factors, including the condition of the rail surface, speed and contact pressure. For emergency braking use, the magnetic strength would normally be as high as possible commensurate with stopping the train as quickly as possible without injuring passengers in the process, and assuming that the strength was compatible with other lineside systems and services. MTBs could also be used to condition the railhead during normal service braking, but the magnetic strength would then be reduced in order to achieve the objective without causing passenger discomfort.

Magnetic brakes that do not use physical contact between brake and rail

The eddy current brake works without physical contact with the rail. An energised coil located in close proximity to the track creates eddy currents which provide a retardation force without any contact. This makes the eddy current brake able to function irrespective of the surface condition of the rail. The eddy currents induced do, however, cause the temperature of the rail to rise. In extreme circumstances, this could result in buckling of the rail. Any use of an eddy current brake should be based on the need to ensure that rail temperatures are not raised to a critical level. The issue of rail heating is not insurmountable as the eddy current brake is used in Germany for service braking on high speed trains.

[9] This overview is based on the contents of a document prepared by Interfleet Technology Ltd for the Rail Safety and Standards Board (RSSB) titled 'Outline feasibility of fitting magnetic track brakes to UK rolling stock', Report No. ITLR-T17544-001, Issue 1A, 3 April 2006.

Reasons for preferring magnetic track brakes for trials on the national railway network

ECBs will perform consistently irrespective of rail head contamination, and this is a major advantage over MTBs. However, the contact that MTBs make with the rail head, although affected by the extent of contamination, will provide some additional benefit through conditioning of the rail head which improves adhesion for following wheels.

The performance of ECBs is highly sensitive to the extent and integrity of the maintenance they receive. It is critical that the correct airgap is maintained between the ECB and the surface of the rail. This means that readjustment of the airgap is necessary for wheel wear and wheel turning for example. The dimensions of the airgap must be monitored constantly as the wrong values could compromise the performance of the system

A supplier of ECBs also advises that:

- ECBs require a significantly greater power supply than MTBs. MTBs require about 1kW per magnet (vehicle batteries can provide this even in the face of total traction power supply loss) while ECBs require about 40 kW per magnet. For ECBs a major strengthening of the vehicle auxiliary power supply would be required.
- It is possible that ECBs will increase axleloads significantly when they are active, unlike MTBs which have no such influence. This is due to the fact that in creating the stopping electro motive force a large attractive force is produced between pole shoes and the rail. The train's suspension is used to resist this and maintain a typical airgap of 6-7 mm between pole shoe and rail. This must be taken into account when designing wheelsets and bogie frames.

In addition to the possible concerns regarding ECBs indicated above, the RAIB believes that MTBs are a more suitable choice for testing on the main line railway network because:

- There is greater experience of their use internationally than is the case for ECBs and this helps to provide confidence in the technology;
- The assessment of the implications of their use on the national railway network is more advanced than is the case for ECBs

Comparison between recommendations in the AWG and RAIB investigations into low adhesion events during autumn 2005

Appendix E

The table below provides a comparison between the recommendations contained in the AWG's investigation into low adhesion events during autumn 2005 (the 'Goff report') and the recommendations contained in this report.

AWG Recommendation	RAIB Recommendation
1 NR should develop a rail treatment strategy that is consistent with its own research and that optimizes the advantages of available methods of treatment as well as the versatility of its equipment.	**5** **Network Rail** to: • plan and execute trials in conjunction with train operators to validate changes made to rail head treatment for autumn 2006 and assess potential adjustments for autumn 2007 • develop a strategy for rail head treatment in consultation with TOCs, based on the outcome of the trials
2 NR should construct a rail treatment programme that is consistent, capable of delivery, and not compromised by conflict with engineering possessions.	Implicit in recommendation 5
3 NR should ensure that its own and its contractors' resources are sufficient to deliver the programme as planned.	No equivalent RAIB recommendation
4 NR should share with TOCs the results of its research into methods of rail treatment, and the logic of its strategy.	Implicit in recommendation 5
5 NR should undertake further research into the nature of residual contamination following water jetting.	No equivalent RAIB recommendation
6 NR should, in conjunction with TOCs, monitor the delivery of rail treatment on a local basis.	Implicit in recommendation 5

AWG Recommendation	RAIB Recommendation
7 NR should review systematically with TOCs the location of rail treatment sites to ensure that they reflect the needs of modern rolling stock, and that the sites of poor adhesion shown in the Sectional Appendix reflect the present situation.	4 **Network Rail** to develop and implement a risk-based strategy for rail head treatment and vegetation control in consultation with train operators. The strategy should be based on a review of recent data and take particular account of locations such as the approaches to junctions and level crossings where the consequences of an overrun could be severe. At high risk locations such as junctions, level crossings and steep gradients, consideration should be given to one or more of the following solutions: • - the targeted application of Sandite; • - application of Sandite using strategically placed fixed applicators; • - temporary restrictions in operational use (e.g. avoiding the use of a junction); • - temporary modification of signalling controls to extend effective overlaps beyond signals; • - instructions to selected trains to perform running brake tests in order to assess the state of adhesion • - other effective measures defined by parties involved in managing the risk from low adhesion
8 NR should carry out, in conjunction with TOCs, a systematic review of lineside vegetation, and develop local, prioritized, programmes for treatment.	Covered by recommendation 4

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AWG Recommendation	RAIB Recommendation
9 NR should review the effectiveness of swab testing as a realistic means of providing post incident information, and if necessary develop a procedure that specifies how and when swabs should be taken and how the results should be interpreted	**7** **Network Rail and train operators** to develop a joint strategy for investigating adhesion-related overrun and SPAD incidents that addresses: • Which low adhesion incidents are investigated: ○ criteria for undertaking an investigation (e.g. length of overrun, potential severity of outcome); ○ whether different levels of investigation are appropriate and if so, the criteria that apply to each one. • What data is gathered, when, how and by whom: ○ Justification for gathering each item of data; ○ When wheel swabbing is appropriate and clear guidance on the extent and number of rail swabs to be undertaken; ○ Train data recorders; ○ Brake Control Unit; ○ Traction Control Unit; ○ Network Rail and TOC staff responsibilities. • Whether enhancements can be made to existing swabbing techniques to improve the value gained from swabbing; • Management of investigations; • Use of alternative approaches or technology to estimate levels of contamination and/or adhesion available.
10 TOCs operating fleets not equipped with sanders should develop business cases for their fitment, where permitted by Railway Group Standard GM/RT2461.	**9** **Train operators** to fit automatic sanding equipment to those multiple units of five cars or less that are not currently so equipped, unless they are specifically excluded from doing so by GM/RT2461

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AWG Recommendation	RAIB Recommendation
11 TOCs operating fleets with sanders should ensure that the equipment fully exploits the scope allowed by Railway Group Standard GM/RT2461.	**1 Train operators to:** • make modifications to multiple units already fitted with sanding equipment to permit application of sand in brake step 2 and above (or the equivalent of brake step 2 and above on multiple units fitted with step-less brake controllers) for the duration of the period when the WSP system is active on the leading vehicle • adjust, as appropriate, rolling stock maintenance activities during the autumn low adhesion period to include enhanced monitoring of sand hoppers to ensure that sand is always available • review their maintenance policies and practices for sanding systems to check that they are aimed at ensuring that they system continues to deliver sand to the point where wheel meets rail 12 **RSSB** to carry out research in conjunction with Network Rail and train operators into the implications, (cost, benefits and disbenefits) of: • adopting enhanced sanding rates under emergency conditions above a defined speed threshold (either activated manually by the driver or automatically activated by the placing of the brake controller into the emergency position when WSP is active) • allowing leading wheel sanding for high speed emergency braking • permitting units other than the leading unit to dispense sand under emergency conditions • methods of avoiding the problem of excessive sand causing failures to operate track circuits (e.g. use of different materials or additives) 11 **RSSB** to review the relevance of existing sanding parameters within GM/RT 2461 and amend, enhance or supplement them with additional guidance where appropriate. The review is to encompass: • Implications (cost, benefits and disbenefits) of increasing the guide value of 2kg/minute for maximum sanding rate (taking account of the trials undertaken during August 2006 by Southern Railway) • The current sanding initiation threshold (full service and emergency braking) and the effect of reducing it to Step 1 or equivalent value for trains equipped with stepless brake controllers; • The need for criteria covering minimum sanding duration; • The need for criteria on sanding at low speeds including the implications of permitting sanding until the train has come to a stand; • Identification of ways in which currently excluded vehicles (e.g. Classes 142-144, 153) can be equipped with sanders **14 Train operators** to check the sand dispensing rate of each train within their fleets and ensure that it is set to the RGS GM/RT2461 guidance value of 2kg/minute except where a higher value has been permitted

AWG Recommendation	RAIB Recommendation
12 ATOC Engineering Council, together with TOCs operating Class 170 fleets, should identify and resolve any problem with WSP performance.	No equivalent RAIB recommendation
13 ATOC Engineering Council should consider the establishment of performance criteria for train braking systems in low adhesion conditions for use when specifying new and modified rolling stock.	10 **RSSB to** lead research into ways of deriving quantitative criteria for braking performance under low adhesion conditions and the implications of each identified approach (including the potential impact on railway infrastructure). The research should include a consideration of the levels of adhesion against which performance (e.g. stopping distances or deceleration rates) should be demonstrated. The implications of adopting the approach proposed in the draft second issue of the high speed rolling stock TSI should be considered. The results from the research should be incorporated into the relevant RGS as appropriate and disseminated to those who are revising the high-speed rolling stock TSI
14 Where dynamic brakes are used, TOCs should ensure that driver training and briefing fully address their characteristics in poor adhesion conditions	No equivalent RAIB recommendation
15 TOCs should ensure that, where appropriate, driver instructions provide guidance on class-specific characteristics, including the behaviour of single unit formations.	No equivalent RAIB recommendation
16 ATOC Operations Council should review the appropriateness of clause 5.4 in Guidance Note 007 in relation to braking techniques when stopping at through stations.	No equivalent RAIB recommendation
17 ATOC Operations Council should review the appropriateness of the initial use by drivers of brake step 1 in conditions of poor adhesion. .	2 Train operators to: • Modify as appropriate their instructions to drivers regarding the braking of trains equipped with a WSP system in low adhesion conditions to ensure that if the expected level of retardation is not achieved during the initial stage of braking, the optimum position of the brake controller is immediately selected to maximize braking efficiency. This may involve selecting a full service brake application or, where appropriate, an emergency brake application. • Brief any revised instructions to drivers.

AWG Recommendation	RAIB Recommendation
18 TOCs should review their autumn plans to increase the length of train formations where appropriate	3 **Train operators** of multiple units operating in single unit formations to consider increasing the length of train consists during the autumn low adhesion season where reasonably practicable, e.g.: • where rolling stock is available • where platforms can accommodate longer trains • where, based on the train operator's review of low adhesion events and knowledge of problem areas for adhesion, there is a demonstrable benefit in so doing on specific routes and/or at specific times of day
19 TOCs should develop procedures for post incident investigation of station overruns, ensuring that both operating and fleet expertise, as well as drivers, is routinely involved.	Addressed by RAIB recommendation 7
20 If the industry considers that station overruns are a major safety risk, it should institute a procedure for the reporting and investigation of such events, to assist monitoring and understanding of underlying causes. A definition of station overrun should be agreed.	Addressed by RAIB recommendation 7
21 The industry should commission research designed to provide an understanding of the "wet rail" phenomenon	8 **RSSB** to extend research and testing into how severe low adhesion conditions occur with particular reference to the phenomenon of micro layers of contamination on rail surfaces, invisible to the eye. The research will seek to establish the nature of the contaminant, how it reaches the rail and bonds with it, the circumstances under which the contaminant poses a particular threat to train braking (e.g. the factors that exacerbate its impact), the factors that determine how long it endures, possible methods for identifying its presence and methods for preventing its formation and dispersing it
22 The industry should commission work to establish the extent to which wheel contamination is a problem.	No equivalent RAIB recommendation

AWG Recommendation	RAIB Recommendation
23 The industry should continue to develop ways of providing location specific adhesion forecasts that are relevant to the needs of infrastructure maintainers and drivers.	**7** **Network Rail** to conduct a review with ADAS to determine the scope for improving the accuracy of low adhesion prediction **18** **RSSB** to establish a study into the potential uses of systems on modern rolling stock to: • automatically sample adhesion conditions, e.g. by the controlled braking/release of a single wheel-set on service trains (other than during train braking) • establish the profile, nature and distribution of low adhesion conditions on the national rail network currently and provide input to WSP simulation packages • improve intelligence about adhesion conditions in real time, e.g. use of wireless data transmission to feed details of low adhesion conditions encountered during braking to a monitoring system. The study should take into account operating experience with the Low Adhesion Warning System (LAWS) and consider the lessons learnt in relation to the development of a network wide solution for monitoring low adhesion conditions. The study should be developed in the context of the work currently being undertaken by RSSB in research project T540, 'Scoping and Development of the Adhesion Management System'. The output from this study must include consideration of how the information can be used by the railway industry including the need for signallers and drivers to be made aware of low adhesion conditions in real time
24 The industry should consider what adhesion-improving remedies can be applied to rolling stock that is currently outside the scope of Railway Group Standard GM/RT2461 (e.g. 14X and 153).	Addressed by RAIB Recommendation 11
No equivalent AWG recommendation	**13** **Train operators** to ensure that until RGS GM/RT2461 has been reissued, clauses on sanding are contained within specifications for new rolling stock. TOCS should specify, as a minimum, the requirement for continuous sanding while WSP is active in Brake Step 2 (or equivalent for trains equipped with stepless brake controllers) and above and a sanding rate of 2kg/minute

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AWG Recommendation	RAIB Recommendation
No equivalent AWG recommendation	**13** **Train operators** to ensure that until RGS GM/RT2461 has been reissued, clauses on sanding are contained within specifications for new rolling stock. TOCS should specify, as a minimum, the requirement for continuous sanding while WSP is active in Brake Step 2 (or equivalent for trains equipped with stepless brake controllers) and above and a sanding rate of 2kg/minute
No equivalent AWG recommendation	**15** **RSSB** to establish a project to: • measure the accuracy of existing WSP simulation rigs that could be used to support rolling stock approvals. This validation should include reference to records obtained from train data recorders following actual incidents and full-scale testing as appropriate. The latter should include a direct comparison between UIC detergent test data and a simulation of the same... • examine the feasibility of extending the capability of an existing WSP simulation tool in order to predict more accurately the behaviour of an entire train in low adhesion conditions (e.g. allowing for rail head conditioning, the effect of sanding and more than one vehicle). The results from the project should be used to inform the developing Euronorm on WSP equipment testing
No equivalent AWG recommendation	**16** Subject to the successful development of the simulation tool described in Recommendation 15, **RSSB** to undertake a programme of modelling to evaluate the impact of different control strategies for minimising stopping distances under various low adhesion conditions. The simulation should specifically address potential alternative strategies for extreme circumstances including: • Changing WSP control algorithms for the level of slip permitted from the current value of 17-20%. • permitting different levels of slip on wheels on the same train to optimise overall braking during low adhesion conditions. All the simulations should be designed to evaluate the effect of different strategies on braking performance and rail head conditioning and should include simulations with sanding operative. The results from the programme should be shared with those responsible for drafting relevant high-speed and conventional TSIs for possible inclusion in new or revised versions of those documents

AWG Recommendation	RAIB Recommendation
No equivalent AWG recommendation	**17** **RSSB** to initiate a project to evaluate the costs and benefits of equipping multiple units operating over the British mainline network with magnetic track brakes for use in emergencies under low adhesion conditions. The project will: • Address and resolve the outstanding issues identified in Interfleet report ITLR-T17544-001 • Subject to successful resolution of outstanding issues, specify and procure magnetic track brake (MTB) equipment and fit it to a small number of units. The units chosen should represent different traction types with different operating regimes and operate in different geographical areas. • Develop and implement trials of these units, incorporating in-service experience and specific comparative tests with a similar unit not equipped with MTB The project will aim to determine whether MTBs are a cost effective solution for new-build rolling stock and/or retrofitting to existing rolling stock
No equivalent AWG recommendation	**19** **Network Rail** to review ERTMS low adhesion assumptions in the light of the findings of this report and consider whether any changes are needed to ERTMS design or operating parameters in the light of the review.

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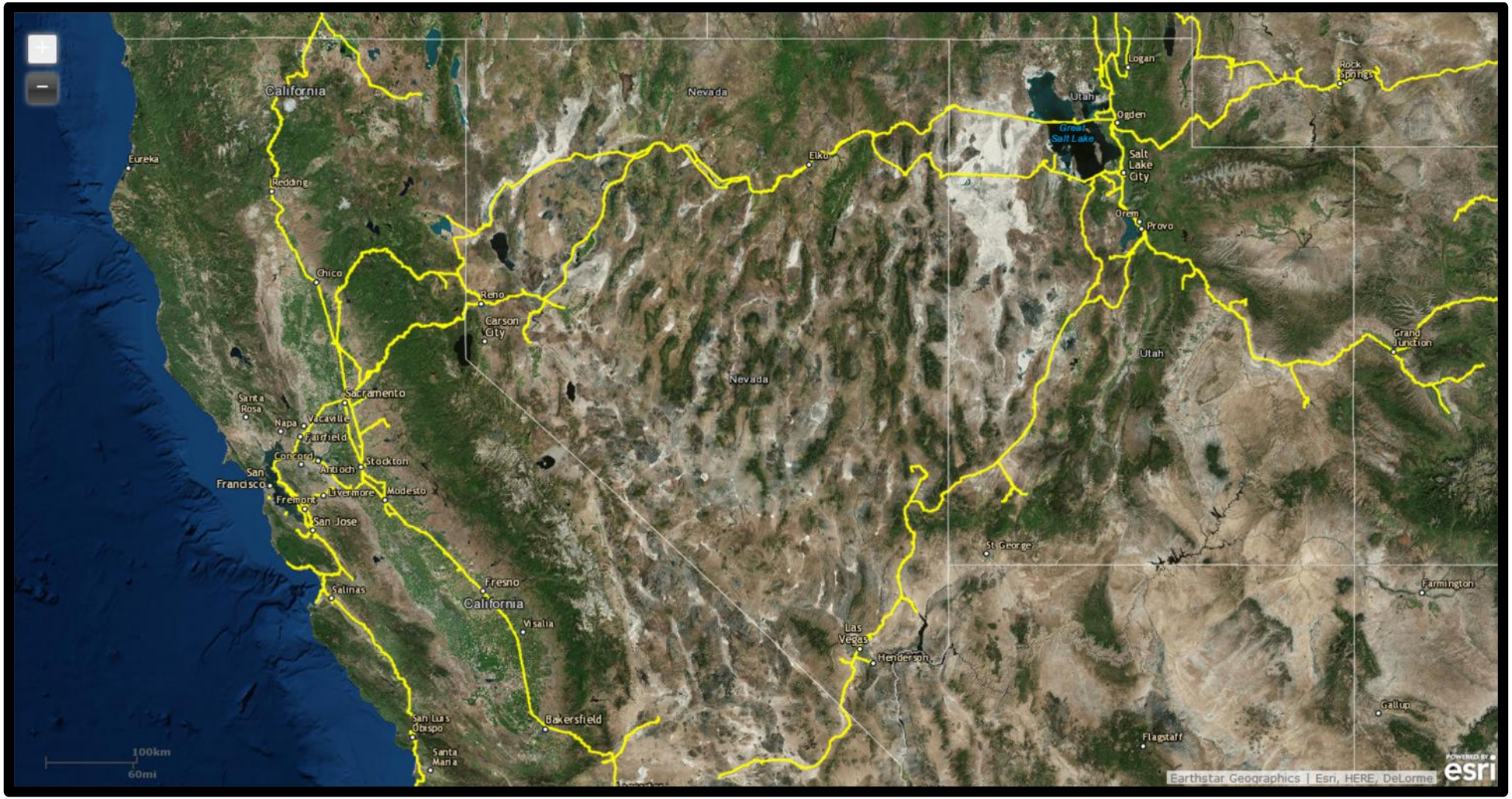
Aberdeen Carolina & Western Railway Company, System Map of BNSF Railway
http://www.acwr.com/economic-development/rail-maps/bnsf

The image below is a screenshot of the interactive map above (captured May 6, 2016):



Centers for Disease Control and Prevention
CDC 24/7: Saving Lives, Protecting People™

Providing National and World Leadership to Prevent Workplace Illnesses and Injuries NIOSH

Coal dust

Synonyms & Trade Names

Anthracite coal dust, Bituminous coal dust, Coal mine dust, Lignite coal dust

CAS No.

RTECS No.

GF8281000

DOT ID & Guide

1361 133

Formula

Conversion

IDLH

N.D.
See: IDLH INDEX

Exposure Limits

NIOSH REL

TWA 1 mg/m? [measured according to MSHA method (CPSU)]
TWA 0.9 mg/m? [measured according to ISO/CEN/ACGIH criteria]
See Appendix C (nengapdxc.html) (Coal Dust and Coal Mine Dust)

OSHA PEL

TWA 2.4 mg/m? [respirable, < 5% SiO_2]
TWA (10 mg/m?)/(%SiO_2 + 2) [respirable, > 5% SiO_2]
See Appendix C (nengapdxc.html) (Mineral Dusts)
[Note: The Mine Safety and Health Administration (MSHA) PEL for respirable coal mine dust with < 5% silica is 2.0 mg/m?, or (10 mg/m?) / (% respirable quartz + 2) for coal dust with > 5% silica.] See Appendix G (nengapdxg.html)

Measurement Methods

NIOSH 0600 , 7500
See: NMAM or OSHA Methods

Physical Description

Dark-brown to black solid dispersed in air.

Molecular Weight

Properties vary depending upon the specific coal type.

Personal Protection/Sanitation

(See protection codes (protect.html))
Skin: No recommendation
Eyes: No recommendation
Wash skin: No recommendation
Remove: No recommendation
Change: No recommendation

First Aid

(See procedures (firstaid.html))

Breathing: Fresh air

Combustible Solid; slightly explosive when exposed to flame.

Incompatibilities & Reactivities

None reported

Exposure Routes

inhalation

Symptoms

Chronic bronchitis, decreased pulmonary function, emphysema

Target Organs

respiratory system

Respirator Recommendations

Not available.

Important additional information about respirator selection (pgintrod.html#mustread)

See also

INTRODUCTION MEDICAL TESTS: 0053

File Formats Help:

How do I view different file formats (PDF, DOC, PPT, MPEG) on this site? (http://www.cdc.gov/Other/plugins/)

(http://www.cdc.gov/Other/plugins/#pdf)

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An Assessment of the Health and Safety Implications of Coal Transport through Oakland

Public Health Advisory Panel on Coal in Oakland
Oakland, California
June 14, 2016

Panelists

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And, for their outstanding contributions as technical reviewers on this project, we also would like to thank:

- Brendan DeCenso, MPH, Public Health Analyst and medical student, University of Pittsburgh School of Medicine
- Elizabeth J Fuller, DrPH, Health Policy Consultant

Endorsements

More endorsements will come in. A final list will be made available prior to the June 27, 2016 meeting.

John Balmes MD	Professor of Medicine, Division of Occupational and Environmental Medicine, University of California, San Francisco
Wendel Brunner MD, PhD, MPH	former Director of Public Health, Contra Costa Health Services
Arthur M. Chen MD	former Public Health Officer, Alameda County; President of Alameda-Contra Costa Medical Association
Larry Cohen	Executive Director, Prevention Institute
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Anthony Iton MD, MPH, JD	Former Director, Alameda County Public Health Department
Richard J Jackson MD, MPH	Professor, UCLA, Former Director, CDC National Center for Environmental Health
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UCSF Benioff Children's Hospital - Oakland

James Feusner MD	Medical Director of Oncology, Children's Hospital & Research Center Oakland; Professor of Pediatrics, UCSF
Celeste Allen MD	Attending physician
Lisa Arcilla MD	Pediatric Cardiology
Rachna Wadia MD	Pediatric Pulmonology
Noemi Alice Spinazzi MD	Chief Resident, Oakland Fellow of the American Academy of Pediatrics

Executive Summary:

An Assessment of the Health and Safety Implications of Coal Transport through Oakland

Public Health Panel on Coal in Oakland, California
June 13, 2016

A panel of public health experts considered the health and safety implications related to the potential transport, storage and handling of coal at the Oakland Bulk and Oversized Terminal (OBOT) proposed to be constructed on the former Oakland Army Base.
The panel reviewed evidence submitted to the Oakland City Council in conjunction with a public hearing held on September 21, 2015 and identified and considered additional sources including scientific articles in peer-reviewed journals, professional reports, press reports, and government data. The panel also conducted original calculations.
This review was conducted in the context of the Oakland City Council's upcoming decision concerning the proposed transport, storage, and handling of coal, which will be informed by public health and safety considerations for current and future Oakland workers and residents.
Based on its review, the panel offers the following summary of its findings.

Transporting coal by rail through the City of Oakland and transferring it through the OBOT facility will increase exposures to air pollutants with known adverse health effects including deaths

- Coal trains significantly increase concentrations of fine particulate matter (PM2.5) in the local community due to emissions of both coal dust and diesel exhaust.
- PM2.5, at levels currently experienced in Oakland, is definitively associated with premature death and increases in lung cancer, hospitalization for heart and lung disease, emergency room visits, asthma attacks, adverse birth outcomes, school and work loss and respiratory symptoms. Introduction of a new PM2.5 source will increase the risks of these poor health outcomes. Even brief spikes from the passing trains may increase health risks.
- Increased emissions of coal and diesel pollutants will likely push current outdoor air concentrations above state, federal, and international air quality standards. However, the U.S. EPA and the World Health Organization (WHO) have determined there is no clear safe level of PM2.5 exposure and effects have been clearly documented below the standards.
- Coal dust typically contains toxics such as mercury, lead, arsenic, cadmium, and crystalline silica. These substances are of high health concern if inhaled or ingested and are known to cause cancer, fetal defects and neurological damage, even at very low doses. There are no known safe levels of exposure to these toxics.

  Atmospheric transport of pollutants generated from coal combustion in Asia back to the Bay Area has increased levels of PM2.5 and air toxics in Oakland.

There are no proven methods to eliminate or reduce the emission of these pollutants to a safe level

- Use of covers for coal cars has been asserted to prevent emissions of coal dust, but this approach is largely experimental and has not been demonstrated in the field to be safe, reliable or effective. Since the panel could find no evidence that covers for coal train cars are currently in use in the U.S., it is impossible to vouch for their safety regarding the possibility of combustion due to the confinement of coal.
- Use of surface sprays to coal for transport has been asserted to achieve partial emission control but such chemicals degrade over time. Through travel from Utah, the surfactants will degrade and will not significantly reduce coal dust emissions locally.

There are inherent hazards in transporting and handling coal, including the risk of catastrophic explosion

- Since coal is inherently combustible, each step in its handling creates hazards for workers and nearby communities.
- Project proponents assert that all inherent hazards can be managed by use of a closed facility that will enable transfers and storage to be completed in a confined space. We have not identified evidence of safety of these designs in comparable urban settings. Transporting and managing coal in confined spaces creates potential for suspension of coal dust in the air, which can be explosive. Coal dust also poses a hazard for workers if inhaled. Further, we are concerned that the Basis of Design documents do not actually indicate a truly closed system, meaning issues of fugitive dust typical to coal terminal facilities would apply In Oakland.
- If the design plans were to be implemented, the City of Oakland would need to assure vigilance in monitoring, operation, oversight, and prompt remediation to ensure protection of workers, residents, and the environment. This would require active engagement throughout the duration of the facility's operations. The level of oversight required, given the myriad opportunities for violation of safety and environmental protection, would be very difficult to enforce and is unlikely a reliable strategy for protecting health and safety.

The combustion of coal exported from OBOT will contribute to global climate change, resulting in additional adverse health risks to Oakland residents

- If climate change continues to progress, it will cause significant impacts on the health of Oakland residents. These impacts include increased heat and ground level ozone-related mortality and morbidity, displacement and economic insecurity due to storm surges, and sea level rise, and flooding, especially in West Oakland, increased respiratory and cardiovascular illnesses caused by air pollution from more frequent wildfires, food insecurity resulting in worsened nutrition, and migration of disease vectors into the Oakland area as environmental conditions change.

- West Oakland residents are particularly vulnerable to the health impacts of climate change, including increased respiratory and cardiovascular disease, heat-induced illness and death, and food and water insecurity.
- There is a narrow window during which actions around the world can be taken to prevent catastrophic climate change by limiting the overall average temperature on Earth to no more than 1.5°C. On a cumulative basis, combustion of OBOT coal produces a significant fraction of the total amount of CO_2 remaining for the whole world to burn over the next millennium while staying within this limit.
- Exporting coal through OBOT will undermine the local, regional, state and international climate initiatives that will protect public health everywhere—including here in Oakland. In contrast, this investigation finds that coal slated for OBOT is likely to stay in the ground absent availability of this facility, making prohibition of coal a reasonable and effective method for Oakland to contribute to the effort to protect public health globally and in Oakland.

Impacts of coal transport and handling will be greatest in West Oakland, a neighborhood already burdened by significant and inequitable environmental hazards

- Those who live, work and play near the rail lines and terminal will experience more significant exposures than those farther away are less likely to experience.
- High prevalence of poverty, coexisting chronic diseases, and reduced access to health care or coping resources, will make those experiencing these exposures less resilient to disease and disability.
- The transportation and handling of coal in Oakland introduces unique risks and challenges for West Oakland residents, and the implications of exposures are more complex. For example, coal trains in Oakland will add to noise exposures, which would reach levels that increase risk for disrupted sleep and reduced work and academic performance for residents living and working nearby. For vulnerable children, subsequent behavioral problems and reduced educational attainment can have far-reaching consequences.

Together, these findings span hundreds of sources that point in the same direction: If coal is transported, stored, and handled in Oakland, we can reasonably conclude that Oakland residents, in West Oakland in particular, will face increased exposure to several known hazards. It is highly likely that there will be increases in adverse health outcomes along with possible adverse safety outcomes.

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Chapter 1: Resiliency, Vulnerability, and West Oakland

Key Points

We start this assessment of the health and safety implications of coal export with a focus on West Oakland,[1] not only because it is the neighborhood closest to the Oakland Bulk and Oversized Terminal (OBOT) site and likely rail route, but also because this health assessment is ultimately about people and where they live. We also frame this assessment with the definition of health, established in 1948 by the World Health Organization and unchanged since then:

> Health is a state of complete physical, mental and social well-being and not merely the absence of disease or infirmity. (World Health Organization, 1948)

From that perspective, there are many ways that West Oakland is a healthy community. Many of its residents are engaged agents of their lives, embedded in strong social networks and active in transforming the environmental injustices impacting them. This strength and vibrancy is seen in myriad community-based projects that pursue justice and health, such as West Oakland Environmental Indicators Project's 100 x 100 citizen air monitoring project, their near-roadway monitoring project, and their upcoming social cohesion study. The faith community is active in West Oakland, along with many community-based organizations that foster positive cultural identity and service. West Oakland is a powerful community, with numerous organizations and individuals who are engaged for social, economic, environmental and health equity.

This dynamism and resiliency is necessary but insufficient for achieving the full state of health defined by the WHO. Underlying vulnerabilities must also be resolved to do so. In West Oakland, high levels of the following factors make residents exceptionally susceptible to the adverse health effects of harmful environmental exposures:

- chronic disease
- disadvantaged demographics
- low income, low educational attainment, and poverty
- insufficient health-supporting infrastructure

For example, compared to other parts of Oakland such as North Oakland and the hills, residents of West Oakland have disproportionately high exposure to:

- Air pollution
- Noise
- Flooding

This brief focuses on how some populations and communities in Oakland – primarily West Oakland – will be more exposed and susceptible to the health risks of OBOT's coal export.[2]

---

[1] This chapter focuses on West Oakland for its proximity to the terminal and because the most likely route for coal

[2] This write-up about West Oakland was neither co-created with its members nor authentically vetted by them. These are shortcomings. At a minimum though, the findings are likely to be familiar – unfortunately – to any West

In the remainder of this assessment document, each chapter will speak to the particular vulnerabilities associated with its topic. This chapter here, with a focus on vulnerability, is overarching.

Summary of Submitted Evidence

There were several submissions to the City Council that provided evidence that the proposed coal export would disproportionately burden West Oakland. The contributors included Communities for a Better Environment, Earth Justice, Forests Forever, Paul English of the California Department of Public Health, Deborah Niemeier, Professor of Civil and Environmental Engineering at UC Davis, and the report from Multnomah Health Department (Oregon) on the impact of passing coal trains. These sources largely relied upon published journal articles and government data from the state, Alameda County, and BAAQMD.

Three main points were made in the submitted evidence (The Multnomah County report supports these points at the thematic level, with similar findings for its own population):

1. Residents in West Oakland face levels of exposure to environmental health hazards that are already high – and higher than many other residents of the city.
2. Many in West Oakland are more susceptible to a greater number and severity of adverse health outcomes due to poor existing environmental conditions and greater sensitivity to the exposures per baseline health and socio-demographic standing.
3. Many residents of West Oakland have limited financial resources and live in low resource settings, limiting their capacity to adapt to adverse environmental conditions.

The submissions converged on the following conclusion:

Given West Oakland residents have 1) high likelihood of exposure to coal trains and coal operations at the terminal, 2) high sensitivity to environmental hazards, and 3) low adaptive capacity due to economic and structural inequity, **any increase in exposure to environmental hazards related to the coal exports will likely have an adverse health impact on the West Oakland population, possibly with greater severity than for others in Oakland were they to face a similar exposure.**

Findings

Assessment of vulnerability to coal transport and handling in Oakland

Vulnerability, per Crimmins et al. (2016) and Turner et al. (2003), can be defined as follows: "whether or not a person is exposed to a health threat or suffers… adverse health outcomes from that exposure depends on a complex set of vulnerability factors," including

---

Oakland resident, and the spirit with which it is submitted – in the pursuit of health equity – is likely to be supported.

exposure, sensitivity or susceptibility to harm, and the capacity to adapt or to cope. (See Figure 1) Working definitions of these terms are listed below.

- ***Exposure*** is contact between a person and one or more biological, psychosocial, chemical, or physical stressors. Contact may occur in a single instance or repeatedly, in one location or over a wider geographic area.
- ***Sensitivity* or susceptibility** is the degree to which people or communities are affected, either adversely or beneficially, by the exposure.
- ***Adaptive capacity*** is the ability of communities, institutions, or people to adjust to potential hazards. A related term, *resilience*, is the ability to prepare and plan for, absorb, recover from, and more successfully adapt to adverse events.

  (US GCRP, 2016, Ch. 9 as adapted from Intergovernmental Panel on Climate Change, 2014 and National Research Council, 2012)

Figure 1 Determinants of Vulnerability

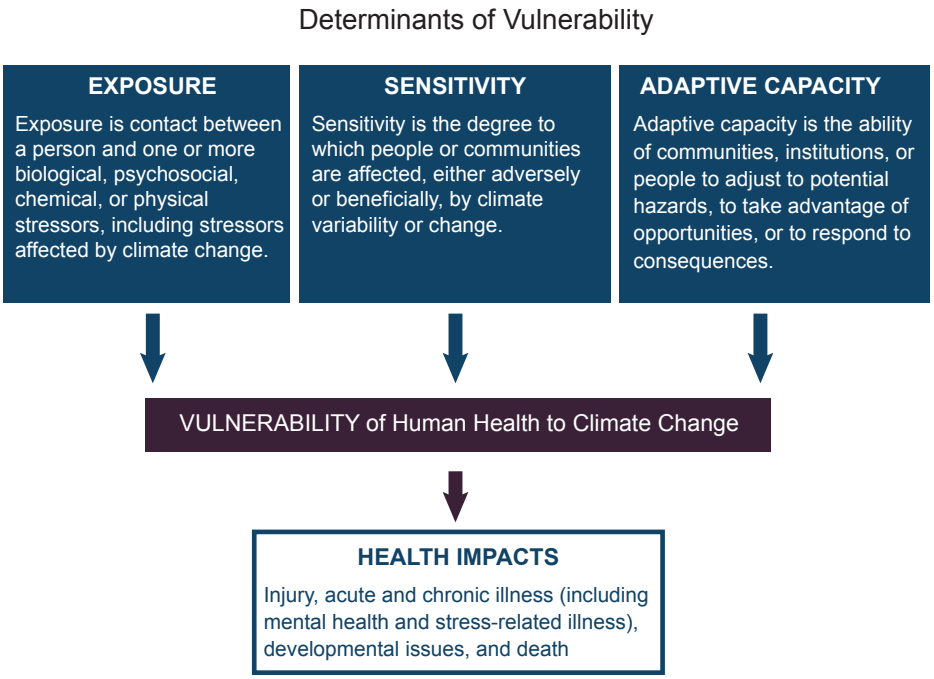


Figure 1: Defining the determinants of vulnerability to health impacts associated with climate change, including exposure, sensitivity, and adaptive capacity. (Figure source: adapted from Turner et al. 2003)[4]

Source, US GCRP, 2016 Chapter 9, referencing Turner, 2003

Exposure

1. **West Oakland residents are in closest proximity to the rails and the OBOT site. Based upon this proximity, West Oakland residents have higher levels of exposures to**

environmental health hazards, including higher exposure (more days of exposure and at higher levels) to:[3]

1.1. air pollution (especially particulate matter and ozone) from trains, ship, coal handling operations, and coal dust

1.1.1. The Oakland Army Base (OAB) EIR finds the project as a whole will have <u>significant and unavoidable air quality impacts</u> (LSA Associates 2012). It states that the project would substantially increase diesel emissions, increasing nearby residents' exposure to toxic air contaminants. The impacts would be concentrated in West Oakland. Emissions would come from ship and rail operations, passenger and transport trucks, and space and water heating (Cambridge Systematics, Inc. 2015).

1.1.2. In a health assessment of the Oakland Army Base conversion to export facilities, the Alameda County Public Health Department calculated the degree to which residents in Alameda county, by census tract, were "freight-impacted."[4] They found that those areas most freight-impacted included West and East Oakland which are adjacent to the tracks, and that, compared to those who were least freight impacted, they were exposed to 2.6 times more diesel particulate matter per day (41.26 kg/day versus 15.83 kg /day; see Figure 2) (Garzón-Galvis et al. 2016).

1.2. noise from the passing trains and terminal operations

1.2.1. (See Chapter 9)

1.3. storm surges and flooding related to climate change

1.3.1. (See Chapter 8)

2. Exposure Inequities: The potential burdens of coal export would fall on the same populations who are already exposed to the highest levels of air pollution, industrial noise, and the worst baseline health conditions. (Multnomah County Health Department 2013)

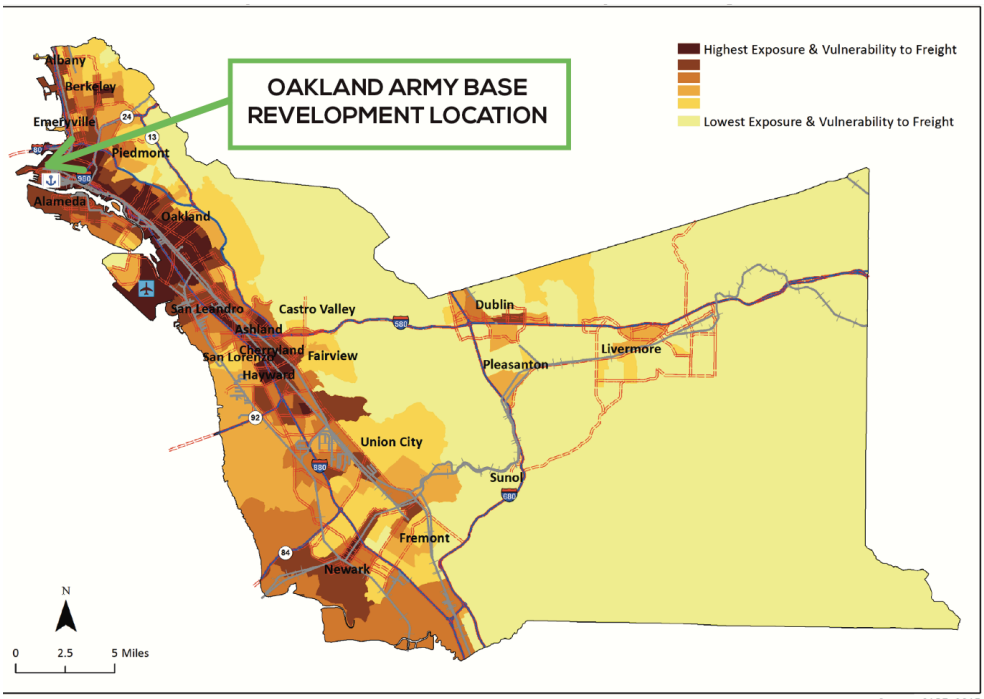
2.1. Rail yards disproportionately impact communities of color. People of color make up a larger proportion of the population near the rail lines and terminal and as a result, people of color may be disproportionately exposed to the effects of coal transportation (Communities for a Better Environment 2010). Data from the

[3] (See other sections of this document for topical exposure details)

[4] Degree of impact from freight combines 1) Proximity to truck routes, rail lines, the Port of Oakland, and Oakland airport, 2) freight-related environmental exposures, such as diesel PM, and concentration of vulnerable populations (those in poverty, young children, seniors, people of color, freight workers)

Figure 2 Vulnerability and proximity to railways, Alameda County

Location of OAB Redevelopment with Exposure and Vulnerability to Freight in Alameda County



Source: CAPE, 2015

2.2. Alameda County Public Health Department (Table 1) shows that the Oakland population living within one mile of rail lines is markedly different demographically than that living outside, with a higher percentage of nonwhites, children and adolescents, as well as a higher percentage living in poverty (ACPHD 2016). These geographic differences have the potential to differentially impact health – for instance, according to a Health Impact Assessment of rail transport in Alameda County: "In 17 out of 18 rail yards in California, a significantly higher proportion of people of color reside within high-risk cancer zones near rail yards than within other areas of the county. In Oakland, 64% of residents within the highest risk cancer zone surrounding the Union Pacific rail yard are African American, compared with 14% of residents in Alameda County as a whole" (Garzón-Galvis et al., 2016).

2.3. One study found that transporting freight by rail may expose a greater number of people living in "environmental justice communities"[5] (Communities for a Better Environment 2010). See Figure 3.

[5] Environmental justice communities, in this analysis, are census block groups that meet one or more of three criteria: more than 25% of residents are people of color (non-white); median household income is less than 65% of

Table 1 Demographic characteristics in relation to rail line proximity

	Between rail lines & 500 ft	Between 500 ft and 0.5 miles	Between 0.5 & 1.0 miles	Other Oakland
Population	9455	73632	102751	219231
% in Poverty	23.4%	30.0%	28.5%	13.7%
% Hisp/Lat	47.9%	43.3%	34.5%	16.2%
% White	12.4%	8.4%	11.4%	37.4%
% AA/Black	24.7%	22.2%	28.4%	24.7%
% AmerInd	0.3%	0.3%	0.3%	0.3%
% Asian	11.2%	22.7%	21.0%	15.7%
% PacIsl	0.7%	0.5%	0.9%	0.4%
% Multirace	2.6%	2.4%	3.2%	4.9%
% Other	0.2%	0.2%	0.3%	0.4%
% <18 Years	25.8%	24.4%	22.8%	19.4%
% 65+ Years	7.1%	9.9%	11.1%	14.9%
% Male	50.9%	51.3%	49.5%	47.3%
% Female	49.1%	48.7%	50.5%	52.7%

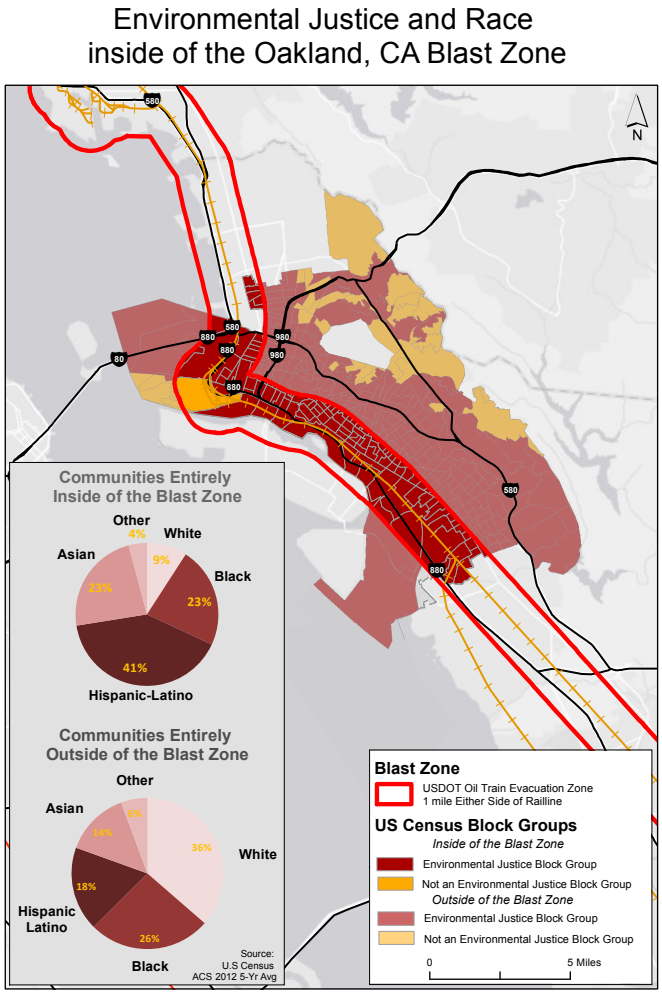
Source: ACPHD 2016

2.4. The Alameda County Goods Movement Plan noted that West Oakland is currently exposed to diesel particulate matter (DPM) ambient concentrations about three times as high as average concentrations within the Bay Area. (Cambridge Systematics, Inc. 2015)

2.5. The California Environmental Protection Agency rated parts of West Oakland as some of the highest census tracts in the State burdened by pollution. For example, some tracts are as high as the 78th percentile for overall pollution burden and in the top percentile for clean-up sites compared to all other CA census tracts (English, 2015).

statewide median household income; more than 25% of households are linguistically isolated (no English speaker older than 14).

Figure 3 Environmental Justice and Race inside the Oakland blast zone



Source: Crude injustice on the rails, Communities for a Better Environment

Susceptibility

3. Living near rails and terminal operations is associated with heightened susceptibility to adverse morbidity and mortality outcomes.

3.1. The Alameda County Public Health Department states that "Any additional sources of air pollution will have a significantly greater impact in an area already disproportionately burdened by multiple sources of air pollution and with high rates of emergency room visits and hospitalization for asthma and cancer risk from existing pollution." (ACPHD, 2015)

3.2. Areas of West Oakland had some of the highest rates of emergency room visits for asthma for children in Alameda County (Garzón-Galvis et al., 2016). Data provided by the Alameda County Public Health Department indicate that West Oakland, relative to Alameda county as a whole, experiences roughly twice the rate of asthma Emergency Department (ED) visits, under-5 asthma ED visits, asthma hospitalization, and under-5

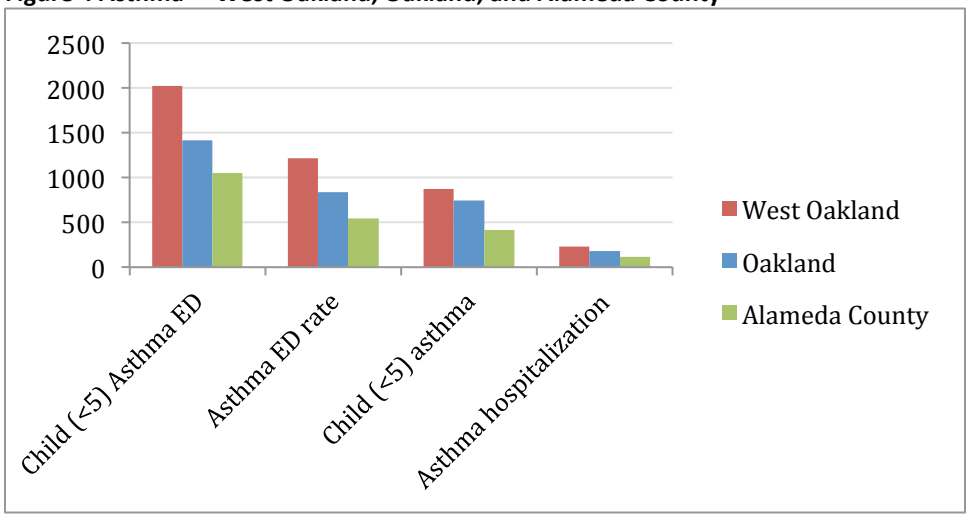
asthma hospitalizations (see Table 2 and Figure 4) (ACPHD 2016). These disparities are all the more profound considering that Alameda County historically ranks among the California counties with the highest asthma hospitalization rates (Roberts et al. 2006).

Table 2 Rates for asthma-related ED visits and hospitalizations in Alameda county (2012-2014)

	West Oakland (zip 94607) Age-adjusted rate (95% LCL-UCL)	Oakland Age-adjusted rate (95% LCL-UCL)	Alameda county Age-adjusted rate (95% LCL-UCL)
Asthma ED rate	1218.4 (1138.3-1298.5)	838.8 (822.6-855.1)	545.8 (539-552.6)
Child (<5) Asthma ED rate	2026.2 (1635.4-2482.2)	1416.4 (1334.2-1498.6)	1053.3 (1016-1090.5)
Asthma hospitalization rate	229.3 (193.2-265.3)	178.9 (171.2-186.5)	112.2 (109.1-115.4)
Child (<5) asthma hospitalization rate	871.5 (622.6-1186.7)	747.3 (687.6-807)	415.4 (392-438.8)

Source: ACPHD 2016

Figure 4 Asthma – West Oakland, Oakland, and Alameda County



Source: ACPHD 2016

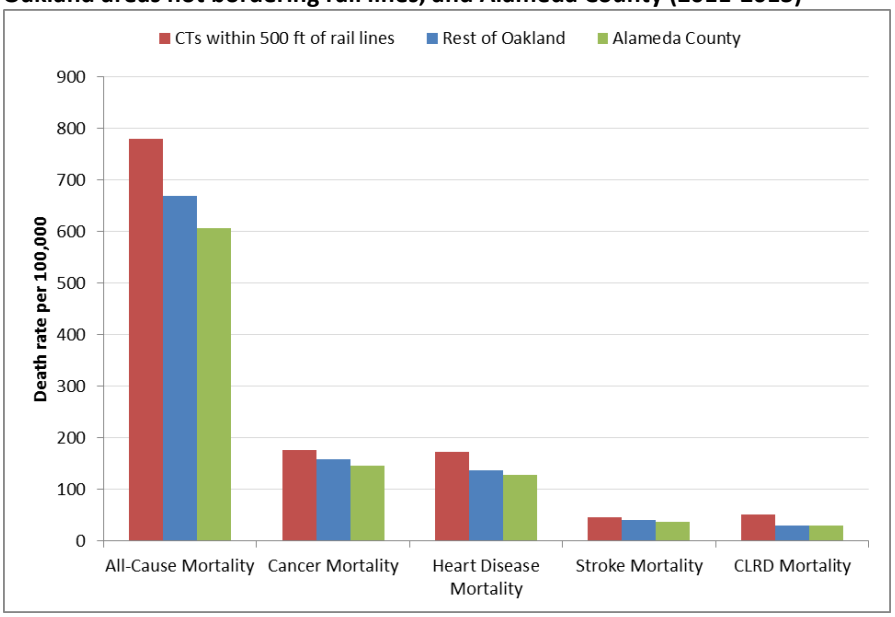
3.3. Oakland furthermore suffers from higher mortality rates than Alameda County as a whole, particularly in areas near rail lines. As displayed in Table 3 and Figure 5, Oakland census tracts within 500 feet of rail lines – compared to Alameda County – have statistically significant higher rates of mortality from all causes, cancer, heart disease, stroke, and chronic lower respiratory disease. (ACPHD, 2016). These higher mortality rates translate to life expectancies 14 years and 12 years shorter for African Americans in East Oakland and West Oakland, respectively, relative to Whites in Oakland Hills (ACPHD, 2015).

Table 3 Mortality by distance from rail system

	CTs within 500 ft of rail lines	Rest of Oakland	Rate Ratio (*=significantly higher)		Alameda County	Rate Ratio (*=significantly higher)	
All-Cause Mortality	780.7	668.3	*	1.2	607.5	*	1.3
Cancer Mortality	176.1	157.7		1.1	145.6	*	1.2
Heart Disease Mortality	172.5	136.6	*	1.3	128.2	*	1.3
Stroke Mortality	46.4	40.8		1.1	37.5	*	1.2
CLRD Mortality	50.6	29.0	*	1.7	29.1	*	1.7

Source: ACPHD 2016

Figure 5 Mortality rates for Oakland census tracts bordering rail lines, Oakland areas not bordering rail lines, and Alameda County (2011-2013)



Source: ACPHD 2016

3.4. BAAQMD's Community Air Risk Evaluation (CARE) Program considers East and West Oakland to suffer most from poor health outcomes due to air pollution, relative to other Bay Area communities (ACPHD, 2015). BAAQMD found that West Oakland's Pollution Vulnerability Index (PVI, a score based upon level of health risk from air pollution) was among the highest quintile of PVI (80 – 100 percentile). Those with the highest PVI score live three fewer years. See Figure 6 (Garzón-Galvis et al. 2016).

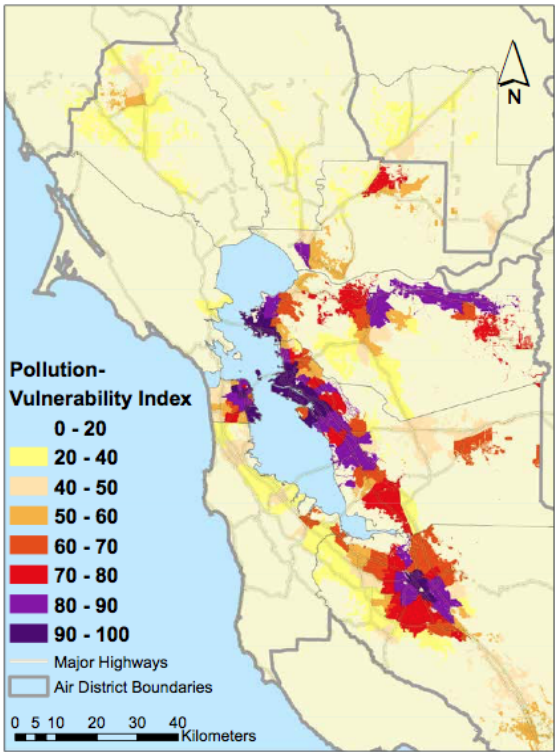
3.5. The 2012 OAB EIR quantified the increase in cancer risk associated with the projected increase in diesel emissions and toxic air contaminants in proximity to the OAB redevelopment, finding maximum cancer risk from the project at 96 cases per million. (Garzón-Galvis et al. 2016)

3.6. Other health hazards disproportionately faced by residents of Oakland redevelopment areas include diabetes and premature or low birth weight infants (Gutierrez 2015a,

Communities for a Better Environment 2010). African Americans in West Oakland are 1.5 times more likely to be born premature or of low birth weight, and 5 times more likely to be hospitalized for diabetes, compared to Whites in Oakland Hills (Alameda County Public Health Department 2008).

3.7. Rates of pedestrian injuries and deaths are seven times higher in the county's most freight-impacted areas (See footnote [4] for definition). (Garzón-Galvis et al. 2016)

Figure 6 the pollution-vulnerability index by zip code



Source: BAAQMD 2014b

"The figure displays the accentuated vulnerability of West Oakland and East Oakland, using the BAAQMD's Pollution Vulnerability Index (PVI), whereby low and high values of the PVI correspond to low and high health impacts, respectively. Vulnerability is constructed to combine existing rates of mortality and illnesses together with exposure to PM and ozone when determining health impacts related to air quality. "Thus the highest PVI values occur where TAC and PM concentrations are high and where health records indicate higher rates of illness associated with air pollutants." (BAAQMD, 2014b)

4. Lower socio-economic standing can increase susceptibility to adverse health impacts of the coal export.

4.1. The BAAQMD analysis found that, on average, compared to areas with the lowest PVI scores, those with the highest PVI score (Garzón-Galvis et al. 2016):

4.1.1. have average annual household income that is more than $40,000 lower

4.1.2. average a year and a half less education

4.1.3. have a five times higher percentage of Black residents

5. **Underlying health conditions increase susceptibility to adverse health impacts of the coal export.**

   5.1. The disproportionately high number of children suffering from asthma in West Oakland would likely experience a further loss of lung function from inhaling even low levels of coal dust (especially those particles of coal dust < 10 microns). (English, 2015)

   5.2. Adults are also subject to increased harm from air pollution due to underlying conditions, such as diabetes, cardiovascular disease, and obesity. (Morello-Frosch et al., 2011; Niemeier, 2015)

6. **Being a person of color, especially being Black is associated with susceptibility to adverse health impacts of coal export.**

   6.1. For instance, in West Oakland from 2011-14, Black children had roughly twice the rate of child (5 – 19yr) emergency department visits for asthma (206.4 per 10,000, 95% CI 176.1-239.7) as did Whites (115.1 per 10,000, 95% CI 62.9-188.0) or Hispanics (92.5 per 10,000, 95% CI 60.9-132.5). See Table 4 (California Department of Public Health 2016)

Table 4 Emergency Department Visits due to Heart Attacks, 2011-2014

		West Oakland (94607)			Alameda County		
		Age Adjusted Rate per 10,000	Lower CI 95%	Upper CI 95%	**Age Adjusted Rate per 10,000**	Lower CI 95%	Upper CI 95%
Overall (All Races/All Ages)		**29.68**	25.43	34.35	**22.01**	21.51	22.53
Adults 35yrs+	**Black**	**36.33**	27.56	46.66	**28.86**	27.24	30.55
	Hispanic	**N/A**	N/A	N/A	**14.39**	13.41	15.42
	White	**107.82**	75.38	147.16	**24.64**	23.8	25.51
	Asian/PI	**13.54**	9.68	18.37	**16.44**	15.63	17.29

N/A= Data not available for counts under 12.

California Environmental Health Tracking Program, Asthma and Heart Attack emergency room visit age-adjusted rates by race/ethnicity, 2011-2014.

7. **In neighborhoods where disadvantaged socio-demographic characteristics interact with environmental exposures, susceptibility from health disparities emerges.** [6]

   7.1. Black children in West Oakland, from 2011-14, had 5 times the rate of hospital admissions as did White children from the rest of Alameda County. (ACPHD, 2015)

   7.2. West Oakland zip code 94607 will likely experience an increase in cancer risk from the OBOT project, even though it already has the highest cancer risk from air pollution in the County, at 689.2 cases per million. West Oakland's diesel cancer risk is three times that of the Bay Area. (Garzón-Galvis et al., 2016)

[6] HHS defines a racial or ethnic health disparity as ''a particular type of health difference that is closely linked with social, economic, and/or environmental disadvantage. Health disparities adversely affect groups of people who have systematically experienced greater obstacles to health based on their racial or ethnic group.'' (U.S. Department of Health and Human Services 2008)

7.3. West Oakland is exposed to multiple sources of diesel pollution, leading to cumulative adverse health impacts of rail yards.

Adaptive capacity

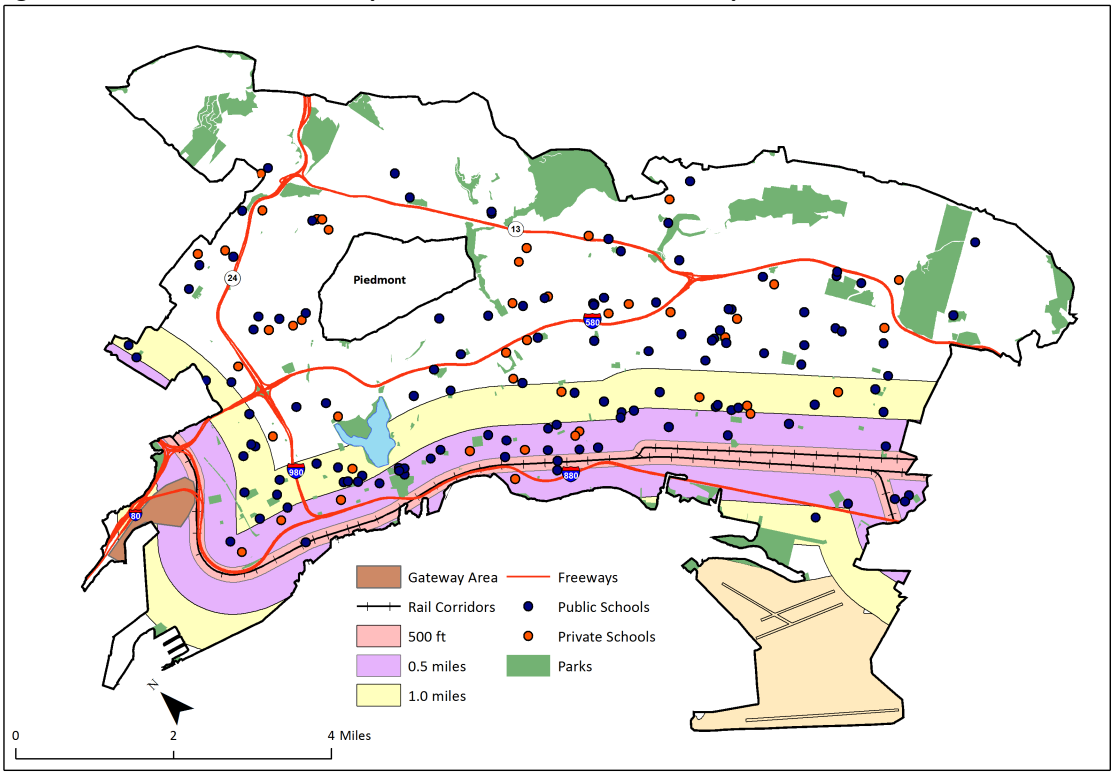
8. Not only do West Oakland residents face higher levels of harmful exposure and adverse outcomes, but due to financial constraints they also have less ability to adapt to and recover from those obstacles relative to residents of surrounding communities.

8.1. West Oakland has an average household income roughly half that of Alameda County as a whole (Rubenstein 2014). An African-American child born in West Oakland is seven times as likely to be born into poverty than a White child born in Oakland Hills (Alameda County Public Health Department 2008).

8.2. Even within Oakland, areas with higher levels of exposure have higher poverty rates – the population living within one mile of rail lines is more than twice as likely to be living in poverty (as shown in Table 1). (ACPHD 2016)

8.3. As illustrated in Figure 7, many important community resources and sensitive sites (schools, parks, community services) are located near the rails and terminal, thereby structurally locking in higher exposures for more vulnerable populations.

Figure 7 Oakland rail corridors, exposure bands, and sensitive receptor sites



Source: CAPE, with rail data from CalTrans, parks data from CPAD 2015b, Gateway area from Oakland Redevelopment Agency, schools from CDE.

Chapter 2: Coal and Diesel-Related Particulate Matter

Key Points

Particulate Matter from diesel engines and coal dust is one of the most important air-pollution-related causes of death and disease. After extensive review of submitted and supplemental literature we found that **transporting coal by rail through the City of Oakland and transferring it through the OBOT facility will increase exposures to air pollutants with known adverse health effects including deaths.**

1. There is documented evidence that coal trains will increase exposure to both diesel particles and coal dust. Both are emitted as fine particles (PM2.5) that will be inhaled into the deep lung. Coal dust also contains larger particles where are known to impact asthmatics.
2. Exposure to these pollutants have been linked in hundreds of peer-reviewed studies, including several conducted in California, with severe health outcomes. These outcomes include premature death, hospitalization for cardiovascular and respiratory disease, emergency room visits, asthma, adverse birth outcomes and school absenteeism. Diesel particles also have a documented effect on lung cancer.
3. These adverse health outcomes are associated with both short-term exposures (from one-hour to one-day) and with exposures over a longer term period (one-month to several years).
4. Increased emissions of coal and diesel pollutants will likely push current outdoor air concentrations above state, federal, and international air quality standards. However, the U.S. EPA and the World Health Organization (WHO) have determined there is no clear safe level of PM2.5 exposure and effects have been clearly documented below the standards.
5. Introduction of a new PM2.5 source will increase the risks of these poor health outcomes. Even brief spikes from the passing trains may increase health risks.

Findings on level of exposure

With the risks of PM2.5 clearly established, the question to answer is: What sort of exposure will Oakland residents have to this pollutant as a result of coal transport through the city? Because Oakland is a major urban center with extensive goods movement activity, it is relevant to first establish baseline exposure. If baseline concentrations of particulate matter are high, then any contribution from coal dust and coal train engines is likely to cause health effects.

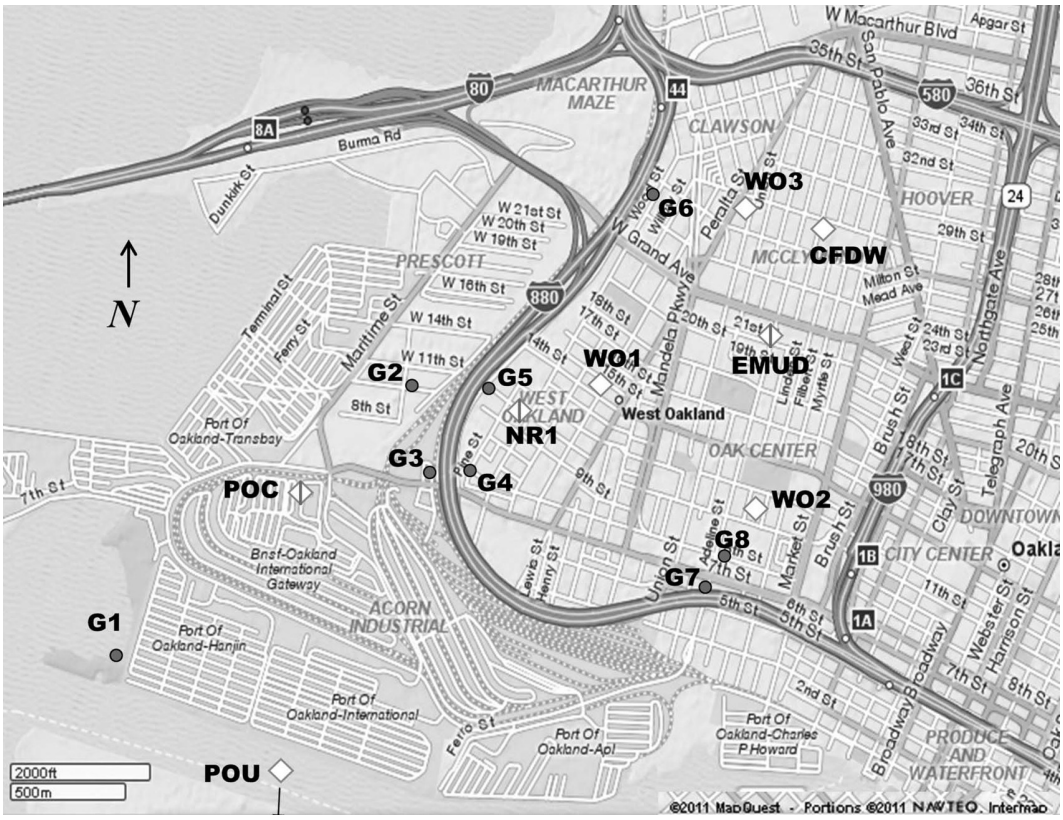
What is the current level of particulate air pollution (PM2.5) in West Oakland?

In 2008, the Bay Area Air Quality Management District (BAAQMD) conducted a special study in West Oakland and several air pollution monitors were placed throughout the area (see Figure 1, below for location of monitors). Among the aims of the study were to measure particulate concentrations near the Port of Oakland. As a result, concentrations of fine particle (PM2.5) were measured for one-month periods in the summer and winter. In addition, there were two

existing monitors already in place as part of separate studies (labeled as EBMUD and CFDW in Figure 1). One was located further downwind from the Port and another at an upwind site in Alameda (POU).

Study results were published in a peer-reviewed journal (Fujita et al. 2013). For the winter month, the average concentration of PM2.5 across all of the monitors was 14.5 micrograms per cubic meter (µg/m^3, which is the standard way to describe PM2.5 concentrations in the air) and 7.4 µg/m^3 in the summer month. However, if we isolate the three monitors downwind and closest to the proposed Oakland Air Base (OAB) project (monitors labeled NR1, WO1, WO3, all of which are on or west of Peralta St.; see Figure 1 below) we can obtain a clearer picture of the pollution levels in the potentially impacted community.

Figure 1 Location of PM monitors in West Oakland



There is a clear gradient as you move further downwind and away from the port (Fujita et al. 2013). **The winter and summer month averages for these three monitors are 15.2 and 7.75 µg/m^3, respectively, with a combined average of 11.5 µg/m^3.** This average of the two months provide a reasonable approximation of the annual average. **To put this average of 11.5 µg/m^3 in perspective, the State of California and Federal annual air pollution standards for PM2.5 are both 12 µg/m^3, and the World Health Organization (WHO) standard is 10 µg/m^3**. The agencies responsible for promulgating these standards -- the California EPA, the U.S. EPA and the WHO -- all clearly stated that the standards **do not represent thresholds** or an absolutely safe level of exposure and that PM2.5-associated death and disease effects definitely occur below these levels. Regardless, the concentrations from 2008 clearly indicate that the citizens

of West Oakland who live within approximately 1500 feet of the proposed OAB project already experience levels of PM2.5 that are close to the existing state and federal standards and above the WHO health-based standard. Additional PM2.5 from diesel combustion and coal dust emissions would likely push air quality in the area over the state and federal standards (see the next section for calculations). West Oakland demographic data indicate there are about 83,000 people residing within 2500 feet of the rail line with a poverty rate of 27%. This renders this population more susceptible to pollution effects due to risk factors associated with poverty including lack of regular medical care and less access to healthy food.

The 2008 BAAQMD study is supported by more recent data collected from a monitor located at 21st and Chestnut, roughly 4000 feet from the proposed OAB site (and therefore much further downwind from the OAB proposed location). At this monitoring site, the three-year annual average ending in 2015 for PM2.5 is 10.8 $\mu g/m^3$. In other words, though this monitor was located more than three-quarters of a mile downwind of the OAB site, the air quality at this monitor still violated the WHO annual PM2.5 standard.

What is the expected increment to particulate air pollution in West Oakland?

Trains that carry coal in uncovered rail cars emit both diesel particles from fuel combustion and blowing coal. Both pollutants can add significantly to the ambient levels of PM2.5. The proposed project as described is expected to bring in up to 10 million tons of coal per year by train to the Port of Oakland. Each train would be more than a mile long with more than 100 uncovered cars. Based on BNSF railway's own statements, each car could lose up to 600 pounds of coal dust between the Utah mines and West Oakland. Specifically, they stated the following: "The amount of coal dust that escapes from PRB [Powder River Basin] is surprisingly large. While the amount of coal dust that escapes from a particular coal car depends on a number of factors, including the weather, BNSF has done studies indicating that from 500 lbs. to a ton of coal can escape from a single loaded coal car. Other reports have indicated that as much as 3% of the coal loaded into a coal car can be lost in transit. In many areas, a thick layer of black coal dust can be observed along the railroad right of way and in between the tracks." If 3% of the projected 10 million tons of year end up being emitted from the coal trains, this amounts to about 620 tons per year that would be emitted into West Oakland (see below for assumptions and calculations).[7] **Thus based on BNSF's own statements and using simple assumptions, approximately 620 tons of coal dust could be blown into West Oakland every year**. Even with a potential reduction of 85% through the use of surfactants, there still would be a significant emission of coal of 90 tons per year. However, an 85% effectiveness is unlikely given the length of the trip and the known degradation of the surfactants over time and space. This is why the Powder River coal shipments necessitated a re-application of the surfactants about halfway through the trip to the coast. In addition, the 85% effectiveness required specific coal load profiles for each car. In their assessment of the literature regarding the impact of coal trains, the Multnomah County Health Department (2013) determined that coal

[7] Calculations for expected increase in coal dust in West Oakland. Assumptions: 1) The distance from Utah mines to Oakland = 800 miles; 2) North-south distance along the track in West Oakland is 1.65 miles; 3) An equal rate of dust leakage per mile during the trip. 4) Proposed 10 million tons per year and 3% lost during the trip. Thus, we 10 million x 0.03 x (1.65/800) = 618.8 tons/year of coal dust emitted on the local community.

dust may travel approximately 500 m to 2 km (1/3 to 1 ¼ miles) from the train tracks, depending on weather conditions and train speed.

It would be useful to translate this increase in coal emissions into a subsequent increase in air pollution concentrations but due to data limitations, it is difficult to estimate the exact increment in PM2.5 expected at the site. We do know, however, that PM2.5 levels will increase from coal dust blowing from the trains and from the increases in diesel fuel combustion needed to haul coal trains which are likely to be heavier than a non-coal bearing freight trains. Moreover, PM2.5 emissions from coal rail cars have been investigated in Washington State. In recent studies of 367 trains in the Columbia River Gorge and other routes in the Seattle area Jaffe et al. (2014; 2015) reported the average peak in PM2.5 concentrations near coal trains was twice that of trains carrying other freight -- specifically 21 versus 11 $\mu g/m^3$, respectively over the background PM2.5 concentrations. In addition, in several cases the enhancement to PM2.5 from coal trains was **over 75 $\mu g/m^3$ with concentrations observed as high as 230 µg/m3**. The BNSF railway requires that a surfactant be applied over the top of coal being transported by rail; therefore, **these high PM2.5 peaks occurred despite existing dust mitigation measures. These extreme short term peaks are of concern given the extensive scientific evidence (as discussed below) of significant adverse health effects, including the possibility of heart attacks, after exposures to PM2.5 as short as one hour.**

We can provide only a general estimate of the additional contribution to PM2.5 from the coal cars versus non-coal freight. Data from Jaffe et al. (2015) indicates the PM2.5 enhancement at different effective wind speeds (train speed plus wind speed at 180 degrees to the train movement). In developing the estimates below, we are assuming a 30 MPH train speed through Oakland based on the CCIG report. Wind analysis from the Bay Area Air Quality Management District shows that 100% of the winds in the summer, when people spend the greatest amount of time outdoors, are from the west. This means that dust from rail operations, including train fuel combustion, will blow directly into Oakland's residential areas, particularly West Oakland. In the winter the wind is from the West about 70% of the time. In addition, on many days wind speeds exceed 10 mph. (Eric Fujita and Campbell, West Oakland Monitoring Report, DRI, 2010). Therefore the effective wind speed under these conditions would exceed 40 MPH or 64 kilometers per hour. With an effective wind speed of this intensity, data from Jaffe et al. (2015, Fig. 4) show short-term PM2.5 enhancements of approximately 20 $\mu g/m^3$ over background with some enhancements of 45 $\mu g/m^3$. Three trains per day passing for 6 minutes every day for a year, would ultimately add 0.25 $\mu g/m^3$ to the annual average concentration of PM2.5. A short-term enhancement of 45 $\mu g/m^3$ would add 0.625 $\mu g/m^3$ to the annual average for the local population. Thus, under these reasonable assumptions, the annual average of PM2.5 would be near to or exceed the federal and state standards for PM2.5 and would clearly exceed the WHO guidelines of 10 $\mu g/m^3$.

The effects from coal-loaded trains on nearby residents bears some resemblance to the effects of road traffic on populations within 100 to 500 feet (and sometimes further) from major roadways. The range reflects local conditions including meteorology, season and background concentrations. Traffic will generate both fine and smaller sized particles and nitrogen dioxide (all emitted from diesel fuel combustion) as well as other pollutants. In their the review of the scientific literature on traffic, the Health Effects Institute (HEI 2010) (an independent non-profit

jointly funded by the motor vehicle industry and U.S. EPA and specializing in research on the health effects of air pollution) concluded that there was a causal relationship between exposure to traffic and exacerbation of asthma with additional evidence of effects on respiratory symptoms, impaired lung function and cardiovascular mortality and morbidity.

It is particularly concerning that these increases in concentrations of PM2.5 will occur in the vicinity of Raimondi Park, where, annually, over 27,000 person-visits are made by mostly youth but also adult athletes and their coaches to engage in soccer and football. These intensive exercises increase respiration rates and the total amount of pollution dose.

These increment to the annual averages calculated above do not include several other sources of PM2.5 from the hauling of coal which could add to the problem including re-entrained coal dust (dust sitting on and around the tracks that will ultimately be stirred up by other trains and wind) and blowing coal stored at the railroad spur or as a result of loading the coal onto the ships for export. In addition, as demonstrated by Jaffe et al. (2014, Figures 6 and 7), measurements from Washington indicate that coal trains produce a substantial amount of coal dust in the form of larger particles between 2.5 and 10 microns in diameter, called "coarse particles". As documented below, coarse particles have strong associations with both mortality and exacerbation of asthma.

To reiterate, these air quality standards and guidelines do not represent a bright line below which exposed individuals face no health risks. Studies from around the world and published in **the scientific literature have clearly documented significant adverse health effects, including both premature death and hospitalization for heart and lung disease, at levels below these standards** (U.S. EPA, 2009). Thus, the data suggest that every increment in PM2.5 is related to negative health outcomes. Specifically, according to both the U.S. EPA and the WHO, a one $\mu g/m^3$ increase in PM2.5 is associated with a 1.6% increase in death from cardiovascular disease. There are similar impacts on hospitalization and emergency room visits and even larger impacts per $\mu g/m^3$ on asthma attacks, work and school loss and adverse birth outcomes including low birth weight and premature births (Fleischer et al. 2014). When you multiply these percent increases times the large number of people exposed, it results in very large impacts. For example, the WHO and others have estimated over 3 million deaths per year worldwide from exposure to PM2.5, making it the largest environmental hazard in the world (Lim et al. 2014; Anenberg et al. (2010).

Findings of health effects associated with PM2.5 exposure

- Fine particles, also called PM2.5 or particles below 2.5 microns (compared to the width of a human hair which is around 70 microns) are a well-documented health hazard. PM2.5 is inhaled into the deep lung and causes systemic inflammation, a known cause of subsequent heart and lung diseases. Air pollution standards for PM2.5 were established over 15 years ago by the World Health Organization, the U.S. EPA and the CalEPA.
- Studies from around the world and from California demonstrate important associations between daily exposure to PM2.5 and a wide range of health impacts including respiratory symptoms, school and work loss, asthma exacerbation, emergency room visits, non-fatal heart attacks, adverse birth outcomes (including low birth weight and premature births),

hospital admissions, and death from cardiovascular disease. (A complete review of the evidence can be found in U.S. EPA 2009; Brook et al. 2009 (Official statement from the American Heart Association); Pope et al. 2009).

- Recent estimates by WHO and others indicate that PM2.5 is responsible for over three million deaths per year worldwide (Lim et al. 2012, Annenberg et al. 2010).
- Current state and federal standards exist based on either a 24-hour or annual average. However, studies show that exposures as short as one- or two-hours are associated with significant cardiovascular health outcomes including heart attacks (e.g. Peters et al. 2001; Mar 2005; Urch et al. 2005; Ljungman 2008; Link et al. 2013).
- The populations at greatest risk (though other groups are also susceptible) include infants and children, asthmatics and older individuals with pre-existing cardiovascular or respiratory disease and the elderly (EPA 2009). In addition Bell et al. (2013) found evidence that those with lower education, income, or employment status have higher risk of death from PM2.5 exposure.
- Studies specifically in California demonstrate that daily exposure to PM2.5 and larger particles can lead to early death, increases in hospitalization and emergency room visits for heart and lung disease, asthma and adverse birth outcomes (Ostro et al. 2006, 2009; Malig and Ostro 2009; Malig et al. 2013; Basu et al. 2004; McConnell 1999).
- While specific ambient standards have been established for PM2.5, institutions including California EPA and WHO, have specified there is no clear-cut safe level for these effects. This indicates that every exposure adds to the likelihood of an adverse health outcome (EPA 2009; WHO 2005; CalEPA 2002).
- Diesel engines emit a complex mixture of air pollutants, including both gaseous and solid material. The solid material in diesel exhaust is known as diesel particulate matter (DPM). More than 90% of DPM is less than 1 micron in diameter (about 1/70th the diameter of a human hair), and thus is a subset of particulate matter less than PM2.5. DPM is typically composed of carbon particles ("soot", also called black carbon, or BC) and numerous organic compounds, including over 40 known cancer-causing organic substances including polycyclic aromatic hydrocarbons, benzene and formaldehyde. Diesel exhaust also contains gaseous pollutants, including volatile organic compounds and nitrogen dioxide (NO2). NO2 is important for two reasons: (1) after chemical reactions in the atmosphere, emissions will lead to formation of PM2.5 and ozone and (2) there are documented health effects from NO2 including premature mortality and respiratory disease (Adapted from ARB website, Overview: Diesel Exhaust and Health)
- In 1998, the California Air Resources Board (ARB) identified DPM as a toxic air contaminant based on the published evidence of a relationship between diesel exhaust exposure and lung cancer and other adverse health effects. In 2012, additional studies on the cancer-causing potential of diesel exhaust published since ARB's determination led the International Agency for Research on Cancer (IARC, a division of the World Health Organization) to list diesel engine exhaust as "carcinogenic to humans".

- Because it is part of PM2.5, DPM also contributes to the same non-cancer health effects as PM2.5 exposure. These effects include premature death, hospitalizations and emergency department visits for exacerbated chronic heart and lung disease, including asthma, increased respiratory symptoms, and decreased lung function in children. Several studies suggest that exposure to DPM may also facilitate development of new allergies. Those most vulnerable to non-cancer health effects are children whose lungs are still developing and the elderly who often have chronic health problems.
- Coal dust is also emitted as "coarse" particles which are between 2.5 and 10 microns in diameter. In studies in California, coarse particles have been associated with premature death and various diseases including asthma (Malig and Ostro 2009; Malig et al. 2013

Further support for our assessment of the likelihood of adverse health effects from coal dust and diesel exhaust is provided by the attached letter from Dr. John Balmes and Dr. Michael Lipsett. Together these physician-researchers have over 50 years of experience investigating the clinical effects of PM2.5 on health.

They state the following:

> *In other words, since diesel particles and a significant portion of coal dust fall within the PM2.5 and PM10 size ranges, the health effects consistently linked with ambient PM are also likely to result from exposure to these two coal train-associated pollutants. Hundreds of peer-reviewed scientific articles link PM10 and PM2.5 exposure with premature mortality and with the occurrence of many serious health outcomes, including heart attacks and strokes, lung cancer, as well as hospital admissions and emergency room visits for a variety of cardiovascular and respiratory conditions (including asthma, chronic obstructive lung disease, and respiratory infections).*

Summary of Submitted Evidence

In conjunction with its 9/21/2015 hearing on the Army Base Gateway Redevelopment Project, the city received evidentiary submissions extensively detailing the harmful levels of air pollution and negative health effects that would result from shipping coal through Oakland. The documents included peer-reviewed literature, expert opinions, reviews of literature from environmental health organizations, as well as a government report from another community in which coal shipping had been debated and subsequently prohibited. Submitted documents are listed below:

- Letter 9/2/15 - Irene Gutierrez for Earthjustice ("EJ")
- Letter 7/30/15 - Adrienne Alvord for Union of Concerned Scientists ("Alv")
- Environmental, Health and Safety Impacts of the Proposed Oakland Bulk and Oversized Terminal by Phyllis Fox, PhD for Sierra Club ("Fox")

- Technical Memorandum Air Quality, Climate Change, and Environmental Justice Issues from Oakland Trade and Global Logistics Center by Sustainable Systems Research, LLC for Earthjustice ("SSR")
- Testimony to City Council 9/21/15 - Dr. Jasmin Ansar, Economics Professor at Mills College ("Ans")
- Manuscript - Dr. Daniel Jaffe et al., "Diesel Particulate Matter and Coal Dust from Trains in the Columbia River Gorge" ("Jaf")
- Letter 9/21/15 - Dr. Bart Ostro ("Ost")
- Critique of Health & Safety Assessment by Bart Ostro and Lora Jo Foo (draft) ("OC")
- The Human Health Effects of Rail Transport of Coal Through Multnomah County, Oregon ("Mul")
- Letter 9/18/15 - No Coal in Oakland ("NCIO")
- News Article - Ashley Ahearn, "What Coal-Train Dust Means for Human Health" ("Ahe")

Because the body of evidence surrounding particulate matter is so vast, the above documents had to summarize large number of primary sources that each focus on individual health effects arising from exposure. In our subsequent analysis, we identified roughly 80 unique primary sources that directly speak to the dangers faced by West Oakland with respect to coal dust and increased diesel emissions due to coal shipping -- over one-half of the references came from the peer-reviewed literature, and one-fifth from government reports or the WHO. We also reviewed those submissions to the City Council that support coal shipments and touched on coal dust and diesel emissions ("SB", "JH", "Bur", "HDR"). Table 1 (see chapter appendix) summarizes key findings from our review, the submission(s) contributing to each finding, and source material used to substantiate each finding. It is important to note that the topical brief forming the basis of our air quality assessment draws upon both the submitted evidence and findings from additional review. Table 1 illustrates only the scope of evidence currently in the record (submitted for the 9/21/2015 hearing), and does not necessarily represent the scope of existing evidence, nor does it place a limit on the panel's conclusions concerning these issues.

Chapter 3: Assessment of Mitigations for Fugitive Coal Dust

Key Points

As follows are mitigation measures proposed by the developer to prevent coal dust exposure, and comments on the potential for those measures to reduce the risk of endangerment to public health and safety.

In this instance we drew significantly from original investigation as well as submitted evidence. In particular some panelists called rail car cover companies directly, and the panel also reviewed a memo produced by Lora Jo Foo and submitted to the City on June 2, 2016.

Based upon what we have learned to-date, we find that no proposed mitigations for coal dust can be considered reliable, safe, or effective:

- Use of rail car covers for the purpose of preventing exposure to dust is largely experimental and has not been demonstrated in the field to be safe, reliable or effective. And, since could find no evidence that covers for coal train cars are currently in use in the U.S., making it impossible to vouch for their safety regarding the possibility of combustion due to the confinement of coal.
- Further, use of surface sprays to coal for transport has been asserted to achieve partial emission control but such chemicals degrade over time. Through travel from Utah, the surfactants will degrade and will not significantly reduce coal dust emissions locally.

Findings

From direct interviews with companies that have designed covers for coal train cars we found they have never field tested them to determine if they are effective in preventing the escape of fugitive coal dust during the transport of coal. While a number of these cover designs may be commercially available today, none have made it to market.
The Federal Railroad Administration (FRA) does not issue approvals for rail car covers and is not involved with testing for coal dust emissions. Neither FRA nor any federal agency has established standards for field testing the effectiveness of coal covers' containment of coal dust.

Mitigation measure #1: Coal train car covers will be used to prevent fugitive dust emissions.

Comments:

Multiple submissions for the 9/21/2015 hearing on the Army Base Gateway Redevelopment Project reported on the lack of commercial availability of coal car covers (Fox, 2015; Ostro, 2015; Sustainable Systems Research, LLC, 2015). Since that time, interviews by Lora Jo Foo of No Coal In Oakland with potential coal car cover producers revealed that of five companies which at one point had planned to provide coal car covers, three companies have progressed to the point of having prototype ready for production, though none have begun commercial manufacturing (Foo, 2016).

As far as we know, no coal car cover has been sold commercially in the U.S., a fact that alone shows the degree to which the technology is untested and therefore experimental. However beyond this issue, coal car covers present an issue of enforceability for the city of Oakland, as federal regulation preempts state and local regulation with regards to railroad operations (Trimming, 2013). Importantly, in her interviews with potential coal car cover producers, Ms. Foo found that one company shelved development due to lack of demand arising from the federal government choosing not to pursue a mandate of coal car covers (Foo, 2016) -- that is, the only entity with authority to enforce coal car covers has chosen not to do so. It is possible that a state include coal dust regulation, such as coal car covers, as part of its State Implementation Plan (SIP) submitted to the EPA, and that the courts harmonize the SIP with federal preemption (Trimming, 2013). However this is no guarantee, as the state regulation must not overly interfere with railroad operations or interstate commerce (Trimming, 2013), an outcome that seems quite likely given the exorbitant cost of coal rail car covers (see below). Moreover, the city of Oakland has no guarantee that the state would bring forth such a regulation. Indeed, in its 9/8/15 submission, the developer's legal counsel argued that federal preemption would hinder any city action (Smith, 2015). The city does, however, have the legal authority to ban coal as a bulk commodity due to its substantial endangerment of health and safety. These findings suggest that rail car covers do not appear to be a feasible option.

Coal car covers present a daunting capital expense. In her interview with one potential producer, Ms. Foo found that a cover for a single rail car would cost roughly $13,000-$15,000, over 20% the cost of rail cars themselves. Moreover, interviews revealed that likely the shippers, not TLS, would be responsible for purchasing or leasing the covers. Given these high costs, the tumbling profit margins of coal operations (Fulton et al., 2014), and probable lack of enforcement, it seems unlikely that shippers would heed the plans laid out by TLS for covered coal cars.

A number of other factors point to the unreliability of coal car covers in preventing dangers to human health, and therefore their farfetchedness as a mitigation measure that will be implemented by shippers:

- Covers are not 100% effective at reducing fugitive dust, as roughly 7 percent of dust leaks out of the bottom of bottom-unloading cars in transit (California Capital Investment Group, 2015). The Basis of Design (BOD) for the proposed terminal calls for bottom-unloading cars (California Capital Investment Group, 2015).
- Covers do not prevent the increased diesel emissions along the rail lines that will result from shipping coal rather than some other good. Coal trains weigh anywhere from 50-200% more than normal freight trains, requiring vastly more diesel fuel (Fox, 2015), with each gallon of diesel fuel emitting incrementally more harmful air pollutants -- including black carbon -- into the surrounding community (Galvis et al., 2013). Even if the same tonnage of a different commodity were to be transported into the terminal, that commodity would spread out emissions over a larger number of trains, and reduce the sharp increases in particulate matter that lead to acute health conditions.

- The enclosed space created by covers leaves coal prone to spontaneous combustion in the rail car (Trimming 2013), which occurs with some frequency:

  "Spontaneous combustion of coal is a well-known phenomenon, especially with PRB coal. This high-moisture, highly volatile sub-bituminous coal will not only smolder and catch fire while in storage piles at power plants and coal terminals, but has been known to be delivered to a power plant with the rail car or barge partially on fire." (Hossfeld and Hatt, 2005)

  PRB coal combusts easier than Utah coal, with PRB BTU/lb anywhere from 8000-9400 (Hossfeld and Hatt, 2005), compared 11400 for the Utah site (Bowie Resource Partners website). However Utah coal still has a much lower BTU/lb than Appalachian coals, and has a history of spontaneously combusting (U.S. Department of Energy National Energy Technology Laboratory, 2002).

Overall, the use of coal car covers is a highly speculative mitigation measure for the city to undertake. Beyond be expensive and likely unenforceable, coal car covers are untested and -- even if 100% effective -- would still not prevent harmful exposures to fugitive dust from coal car bottoms or combustion fires.

Mitigation measure #2: In packing cars, coal dust will be controlled through load profiling and treatment with topping agents to minimize emissions.

Response:

As stated above for rail car covers, the use of topping agents is wholly unenforceable by the city of Oakland. Beyond this issue, perhaps the best demonstration of the impracticality of topping agents is the dispute that has occurred between BNSF and shippers of PRB coal, which ended up before the U.S. Surface Transportation Board (U.S. Department of Transportation Surface Transportation Board, 2011)). The dispute began as a result of derailments that were caused by fugitive coal dust, which has been shown to destabilize rail bed ballast and deposit on tracks (Vorhees, 2010). In order to avoid future derailments, BNSF required that topping agents be applied to coal shipments originating in Wyoming and Montana, and that proper load profiling be used to produce an 85% reduction in fugitive dust. The dispute centered around which party (shippers or BNSF) should pay for the reduction, which would cost upwards of $100 million per year (Vorhees, 2010).

The PRB dispute showed that, beyond being costly, topping agents have lower real-world effectiveness than has been cited by HDR and the developer. Shippers argued before the Surface Transportation Board that no amount of surfactants and proper load profiling could meet BNSF's 85% standard (US Dept of Trans 2011), while BNSF argued that auditing indicated shippers do not regularly adhere to best practices for load profiling in order for topping agents to have the maximum 85% effectiveness (BNSF, 2010). Either way, the 85% threshold would not likely be met. Moreover, those along BNSF railroads have made similar statements about the lack of real-world effectiveness: *"while the railroad requires shippers to spray coal cars with surfactant to keep down the dust, it only is estimated that 30 percent of shippers comply with*

the rule" (Online Public Meeting for the Draft EIS for the Proposed Tongue River Railroad, 2015).

Lastly, topping agents may have negative aquatic and environmental effects, as encapsulated below:

> *"In a concerning aside, the authors noted, based on earlier research, that "surfactants," the chemical adhesives commonly used to reduce coal dust on trains, can boost the ability of coal pollutants to enter the environment, and the Washington State Department of Natural Resources raises similar concerns about surfactants."* (de Place and Kershner, 2013))
>
> *"Potential environmental impacts include: surface and groundwater quality deterioration; soil contamination; toxicity to soil and water biota; toxicity to humans during and after application; air pollution from volatile dust suppressant components; accumulation in soils; changes in hydrologic characteristics of the soils; and impacts on native flora and fauna populations." "The potential impact of dust suppressants on soils and plants includes changes in surface permeability, uptake by plant roots that could affect growth, and biotransformation of the dust suppressants in the soil into benign or toxic compounds depending on the environmental conditions and associated microbiota. Vegetation adjacent to the area where dust suppressants are applied could be impacted by airborne dust suppressants. This includes browning of trees along roadways and stunted growth. These effects will vary since different plants have different tolerances. The potential impact of dust suppressants to water quality and aquatic ecosystems include contaminated ground and surface waters, and changes in fish health. Dust suppressants that are water-soluble can be transported into surface waters and materials that are water-soluble but do not bind tenaciously to soil can enter the groundwater. Fish may be affected by direct ingestion of toxic constituents and also by changes in water quality (e.g., BOD, DO, salinity)."* (Piechota et al., 2002)

<u>Mitigation measure #3</u>: Fully enclosed facilities will prevent fugitive dust emissions. Proper coal storage and handling of coal will prevent hazardous coal dust explosions and spontaneous combustions.

The developer proposes to ship up to 10 million metric tons of coal through OBOT each year, with 2-3 trains arriving at the facility each day (Tagami and Bridges, 2015). Mitigation plans to reduce fugitive dust at the terminal -- including planned use of enclosed storage and water spraying -- will only partly address the issue, and moreover may cause health hazards in and of themselves.

First, full coal cars will sit exposed on the tracks for hours at a time waiting to be unloaded. Sustainable Systems Research, LLC (2015) estimated that up to 650 tons of coal per year could be lost from idling full coal cars due to wind erosion. These emissions will be constant sources of exposure to particulate matter for both terminal workers and residents of areas surrounding the terminal.

While covered storage facilities would prevent further fugitive dust emissions from stockpiles, the enclosed spaces in those facilities promote (1) coal dust explosions due to high concentrations of ambient combustible material (Hossfeld and Hatt, 2005), and (2) fires due to

spontaneous combustion of coal at high temperatures and pressures while sitting in stockpiles (de Place, 2012; U.S. Department of Energy, 1993). Even with proper handling and layering of coal stores, it may be difficult to control combustion in an enclosed environment -- for instance, the U.S. Department of Energy in its Piñon Pine project determined that the only feasible way to store coal in order to prevent it from combusting was to store it outside (U.S. Department of Energy National Energy Technology Laboratory, 2002).

To reduce risks of explosions, the developer proposes continual water spraying in the facility (Liebsch and Musso, 2015). Spraying down coal stockpiles in such close proximity to a waterway could lead to harmful leachates that negatively impact marine life (Ahrens and Morrisey, 2005; Campbell and Devlin, 1997; Johnson and Bustin, 2006).

In summary, the terminal facilities proposed by the developer only partially mitigate exposure to particulate matter, and produce a host of other occupational and public health issues. Like the other mitigation measures, a "state-of-the-art" terminal is by no means a perfect solution.

Chapter 4: Hazardous Toxics Accompanying Coal Dust

Key Points

- Many highly toxic chemicals accompany coal dust. There are no known doses that are risk-free, especially for the very young and for those in communities exposed to multiple toxins.
- Cadmium poses danger as a kidney toxin and cause of osteoporosis. Cadmium exposure is linked to kidney, bladder and lung cancer.
- Mercury toxicity derives from consuming or inhaling this element or its organic form. There is substantial evidence that it reduces mental function especially in the very young and exposure is also linked to heart disease, diabetes and adverse birth outcomes.
- Lead is an infamous toxin, strongly associated with brain and nerve damage, especially in children. It is linked to increased risk for lung, stomach and bladder cancer.
- Arsenic is a known cause of skin, bladder and lung cancer.
- Crystalline silica is a causative agent for lung cancer. Monitoring of silica levels near a coal export facility revealed air levels that exceeded regulatory guidelines.

Summary of Submitted Evidence

Several submissions note that a range of toxics accompany coal dust, furthering the point that there is no clean coal. Phyllis Fox, in her technical report for the Sierra Club (a), provides provides an in-depth discussion of toxics of critical concern:

She discusses that coal contains many kinds of polycyclic aromatic compounds (PAHs), including both naphthalene and benzo[b]fluoranthene (Zhao et al., 2000), two compounds listed by the State of California's Proposition 65 list (California EPA OEHHA, 2016). PAHs are toxic constituents of PM2.5 that have been shown to have mutagenic, carcinogenic, and asthma-inducing effects (WHO, 2003). She also finds that coal dust additionally contains a host of metals and metalloids, including silica, which have been shown to have a negative effect on human health. Although coal is not classified as hazardous, Fox explains that its constituents are, for example, the minimum and maximum levels for arsenic in Utah coal are 1-8ppm, which are approximately 14-114 times the residential risk-based screening level suggested by CEPA (.07ppm). These arsenic levels are also higher than the CEPA industrial risk-based screening level of 0.24ppm (Fox, 2015).

This chapter reviews some of the high profile toxic constituents of coal.

Findings

CADMIUM

This element has multiple well-known toxicities including renal toxicity (1,2,3) and such kidney damage may occur at very low levels of exposure, with even house dust being a contributing factor (4). Cadmium exposure also increases the risk of osteoporosis, associated fractures and decreased quality of life, even at very low exposure levels (5,6,7). This toxin is also classified as an IARC Group I carcinogen (8). Epidemiologic studies have linked cadmium exposure to lung cancer (9,10), kidney cancer (11) and bladder cancer (12). Cadmium exposure is associated with an increase in blood sugar and risk for diabetes (13). An association with overall mortality and environmental cadmium exposure has been found, which risk is independent of kidney damage (14). Furthermore, there appears to be no threshold for this effect (4).

Populations at increased risk for cadmium toxicities include diabetics (5), postmenopausal women and those of reproductive age, (15).

Cadmium serves no laudable effect in human biology, only a deleterious one. Due to a number of industrial processes, including the extraction and combustion of coal, current U.S. and European standards for tolerable weekly intake have already been exceeded in many cities (16,4). There is no known safe dose of exposure for the outcome of increased overall mortality (4,13,14). Given these data, any additional cadmium exposure is highly likely to lead to an increase in disease and death.

MERCURY

Coal carries mercury as a contaminant. This is why coal-fired power plants comprise the largest source of mercury pollution in the United States (17). Airborne mercury in its inorganic form is eventually transported to water and earth, where food sources become contaminated (18). Bioaccumulation of low levels of mercury in aquatic species can lead to high levels of organic mercury levels in people consuming such fish. In fact, the FDA currently advises that young children, pregnant women and nursing mothers limit their amount and type of fish consumption (19) as higher fish consumption in these groups is associated with cognitive problems in young children (20). All forms of mercury are toxic to many organ systems. Airborne and food sources of mercury have both been associated with lower IQs in young children (21). Such cognitive impairment in children is likely to be permanent (22,23). Memory, mood and anger problems have also been associated with mercury toxicity (24,25,26). High levels of mercury are associated with an increased risk of diabetes mellitus, coronary heart disease, and cardio-vascular mortality, but even chronic, low-dose exposure can lead to cardiovascular disease and chronic renal disease (27,28)). Mercury has also been associated with adverse reproductive outcomes including an increased risk of spontaneous abortions (29) and impaired fertility and newborn development (30).

Infants and children, people with iron deficiency and those consuming large quantities of fish are among most vulnerable of populations.

LEAD

Lead, also a component of coal, causes multiple morbidities, some of which occur at very low levels of exposure. Indeed, the Centers for Disease Control and Prevention have steadily lowered the threshold of acceptable blood levels considered dangerous for in children by 88% (from 60 micrograms/dl to 10 micrograms/dl) over the last 40 years (31). The nervous system is the organ complex most vulnerable to lead-induced toxicity (32). Both the peripheral and central nervous systems are susceptible to lead toxicity (33). Children are particularly prone to suffer irreversible central nervous system damage, even at the lowest levels of exposure (34,35,36,37). In fact, there is no known safe dose of lead for developing brains (38). Pre-natal transmission of lead from mother to fetus can also harm cognitive function in infants and children (39). Syndromes consistent with attention deficit and hyperactivity disorder (ADHD) have also be linked to low-level lead exposure (40). In adults, lead exposure increases the risk of hypertension, heart disease and stroke (41). Even very low levels of exposure can lead to increases in blood pressure (42). Lead causes anemia by blocking synthesis of heme, even when blood levels are 10 micrograms/dl or lower (43). IARC deems inorganic lead a probable human carcinogen, likely increasing the risk of lung, stomach and bladder cancer (44).

No safe exposure has been identified for many of lead's severe toxicities. The most severely affected population are the very young. Blood levels of lead are higher among minority children, those in low income households and children living in older homes (34).

ARSENIC

Arsenic, also a component of coal, affects many organ systems. Exposure can occur through contaminated water or by inhalation (45). Some of these toxic effects occur with chronic, low levels of exposure. For this reason, government agencies in several countries have progressively decreased the maximum allowable dose of arsenic in drinking water (46,47,48,49). There are few promising treatment methods (45). IARC has listed arsenic as a human carcinogen since 1980 (50). Arsenic is unique in that it is the only known chemical carcinogen for which there is strong evidence of cancer risk by both inhalation and ingestion (51). Arsenic exposure is associated with a number of tumor types including skin cancer (52), bladder cancer (53), lung cancer (54). Arsenic also has deleterious effects on the nervous system. Long-term exposure may result in neurobehavioral effects in adolescents. The problem may be more severe if lead exposure is also present (55). Arsenic peripheral neuropathy, including sensory loss, pain and muscle weakness, is well-described (56,57). Children's intellectual function can be decreased by arsenic exposure (58). Arsenic is a reproductive toxin, exposures leading to fetal loss and premature delivery (59). Studies have documented a relationship between arsenic exposure and diabetes (60,61). A U.S. study concluded that even low levels of inorganic arsenic may play an important role in increasing the incidence of type 2 diabetes (62). Long-term exposure to arsenic may also increase carotid atherosclerosis (63). Long-term exposure to arsenic also results in an increasing incidence of respiratory disease, including chronic bronchitis (63,64).

Many of arsenic's toxic effects occur at relatively low levels of exposure. The most vulnerable populations include the very young, pregnant women, those who are also exposed to lead and those who have risk factors for or a family history of Type 2 diabetes mellitus.

CRYSTALLINE SILICA

Silica has been known for centuries to cause silicosis and, in the last few decades, has been shown to be a cause of lung cancer. Crystalline silica is a Group 1 IARC carcinogen (65). The silica content of coal dust has made this substance a well-documented occupational hazard (66) a cause of chronic lung disease including fibrotic pneumoconiosis (silicosis), interstitial inflammation, emphysema, fibrotic granulomata and sclerotic nodules (67,68,69). In addition, silicosis increases the incidence of tuberculosis in affected individuals (70). Respirators may be useful in short-term, high-dose exposures, but are generally not useful as the primary means of exposure control due to workplace discomfort, difficulties in communicating with other workers, lack of compliance, and difficulties with obtaining and maintaining a good mask fit (71). Chronic levels of silica dust, that do not cause disabling silicosis, may cause the development of chronic bronchitis, emphysema and/or airflow obstruction, even in the absence of radiological evidence of silicosis (72). On the basis of epidemiological studies, the OEHHA derived an inhalation chronic reference exposure level (REL) for silica – a level below which no adverse effects due to prolonged exposure would be expected in the general public – of only 3 micrograms/cubic meter (73). It is noteworthy that air quality monitoring near a coal export facility in Seward, Alaska revealed crystalline silica levels that exceeded this REL on at least 2 occasions (73).

Chapter 5: Local impacts of international combustion of coal: trans-pacific travel of air pollution

Key Points

As documented extensively in this report, shipping coal through OBOT will negatively impact the health of Oaklanders by releasing coal dust and diesel pollutants during transport. A less tangible, but incredibly important consequence of shipping coal to Asia will be pollution introduced to the Western United States including the Bay Area as the result of the coal being burned in Asia. A wealth of scientific literature has shown that a large fraction of air pollution on the West Coast can be attributed to products of coal burning in Asia that subsequently blow across the Pacific Ocean. By this token, the city of Oakland would in effect be shipping coal to be burned and blown back over itself.

Findings & Summary of Submitted Evidence

Repercussions from Asian consumption of OBOT coal include:

1. **Increased hazardous air pollutants** -- Levels of dangerous air pollutants in the Bay Area -- including $PM_{2.5}$, PAHs, ozone, sulfates, and mercury -- are linearly related with coal consumption on Asia.
2. **Increased mortality in the Oakland area** -- Overseas combustion of coal has a direct, measurable impact on local mortality rates.
3. **An inability to meet air quality standards** -- Pollution resulting from Asian consumption would add to Oakland's already high background air pollution levels, making it unlikely that the city will meet air quality standards. In particular, increased ground level ozone (which also acts as a greenhouse gas) would likely exceed standards.

Evidence submitted prior to the 9/21/2015 hearing on the Army Base Gateway Redevelopment Project spoke to the direct air quality impacts that combustion of coal shipped from OBOT will have on Oakland, the Bay Area, and the world. Below are summarized findings from submitted evidence (also cited are references used in developing those findings), as well as findings from analysis subsequent to the 9/21/2015 hearing:

- Air pollution exposure: As noted elsewhere, burning the nine million metric tons of coal that the developer proposes shipping through OBOT each year will add 22 million metric tons of CO_2 annually to the atmosphere, or 1.5 billion tons of CO_2 over the length of the developer's lease (Gutierrez, 2015a; No Coal In Oakland, 2015; Union of Concerned Scientists; Wisland, 2015). Burning coal in Asia will similarly increase air pollutants, which disproportionately impact the Bay Area. Prevailing westerly winds blow coal burning products across the Pacific Ocean from Asia directly to the western U.S. (Zhang et al., 2008, 2009). Numerous studies have captured the degree to which Asian emissions are accountable for West Coast pollution, the findings of which include (but are not limited to):

- A 2010 study conducted in Oakland indicated that roughly 30% of the region's particulate matter ($PM_{2.5}$) air pollution originated in Asia (Ewing et al., 2010).
- Pacific Northwest air samples detected polycyclic aromatic hydrocarbons (PAHs) from the incomplete combustion of coal in Asia (Lafontaine et al., 2015).
- 14% and 18% of mercury deposits at two sites in Oregon were found to come from Asian air pollution (de Place, 2012b).
- Roughly 20% of ground-level ozone (O_3) in California originates from Asian sources (Lin et al., 2012)
- Production of Chinese export goods adds 12-24% of sulfate pollution over the Western U.S. (Lin et al., 2014).

The adverse health outcomes resulting from exposure to the above mentioned pollutants have been documented elsewhere in this report, however it is important to note that high enough exposure to methylmercury (a byproduct of mercury pollution) causes severe developmental disorders in children (Sustainable Systems Research, LLC, 2015).

- Health impacts and implications: Intercontinental air pollutants have direct effects on human health and the ability of California cities to meet air quality standards, as demonstrated in the studies below:

  - 3-7% of deaths from $PM_{2.5}$ exposure can be attributed to intercontinental air pollutant transport (Anenberg et al., 2014).
  - Asian pollution threatens the ability of the Western U.S. to meet the ozone standards proposed by the EPA of 65-70ppbv, as trans-Pacific contributions to ozone levels currently equal up to 5±5.5ppbv and are increasing at a rate of 0.8±0.3ppbv (Christensen et al., 2015). Other studies similarly found increases in ozone levels (Zhang et al., 2008, 2009)
  - Asian air pollution is associated with increased severity of Pacific storms (Zhang et al., 2007). Natural disasters inequitably impact socioeconomically vulnerable groups, populations which are highly represented in Oakland (Pacific Institute, 2012; Wisland, 2015).

- As with any other commodity, reducing the supply of coal will increase its price and reduce consumption (de Place, 2012b). Therefore it is likely that if the City of Oakland bans coal exports, it will directly reduce fossil fuel consumption and global warming.

For years, California and Oakland have been at the forefront of environmental activism, and through proactive legislation have dramatically reduced both greenhouse gases and the fraction of energy coming from coal (California Energy Commission, 2015; City of Oakland, 2012; Office of Governor Brown, 2015; Wisland, 2015). In allowing coal shipments through OBOT, Oakland and California would sharply contradict these stated goals.

Chapter 6: Responses to Developer Comments Concerning Coal Dust

Key Points

During the course of receiving comments and testimony in September and October, 2015, several comments were made by the developers with regards to risks and exposures to pollution that might emanate from the project, with coal dust being a point of focus. Often there was a rebuttal or alternate view, and these have been gathered from the submitted record to present a cogent flow of information, below. In many instances the Panel provided supplemental review and response.

This section is important to a health assessment because the degree to which the comments are true – or not – will have bearing upon our exposure estimates.

Comments and Responses

Comment by coal proponent:

Little to no fugitive dust will be emitted by the time trains arrive in West Oakland. If proper load profiling, packing, and topping practices are applied, coal dust will only be emitted during initial acceleration away from the loading point. In its Publication AP-42, the USEPA states that wind erosion of coal piles is limited by the amount of erodible material, such that no wind erosion will take place once erodible material is removed. (Liebsch and Musso, 2015)

Response:

The claim that the vast majority of coal dust emissions "*will occur during the initial acceleration phase after the train cars are freshly loaded"* (Liebsch and Musso, 2015) is based on a USEPA report which is not relevant to moving freight. The focus of the USEPA report is on dust emissions produced "by wind erosion of open aggregate storage piles and exposed areas within an industrial facility" (USEPA Office of Air Quality Planning and Standards, 1995). The report states that dust emissions are limited by the availability of erodible coal stored at the facility, however as noted by Dr. Phyllis Fox, rail transport constantly produces erodible material: "movement of cars during transit creates vibrations that break larger pieces of coal into smaller particles, creating a continuous source of dust as the trains travel to their destination." (Fox, 2015). Peer-review studies have confirmed that coal dust particulate matter is produced and emitted throughout the entirety of transit, including at the destination. (Jaffe et al., 2014; Jaffe et al., 2015)

Argument by coal proponent:

The Jaffe et al. (2014) study used measurement devices calibrated for diesel particulate matter detection rather than coal dust detection, and therefore cannot state that the PM captured was coal dust, nor that it was $PM_{2.5}$. Furthermore, the study was conducted in an area of Seattle with already high diesel particulate matter levels. (Tagami and Bridges, 2015)

Response:

The author of the article responds: "The comments about the DustTrak are not really relevant to our findings. The DRX is not a regulatory instrument, but has been used in many scientific studies for PM2.5, as documented in our paper. While it is true that we did not "calibrate for coal dust", nonetheless, the relative response for coal trains and diesel trains that we observed can not be explained by a calibration difference. Doing the calibration they suggested would be a complex and costly experiment. To my knowledge, no one has ever done this." (Personal communication, Dan Jaffe, 2016)

Comment by coal proponent:

Coal dust is not defined as a hazardous material by USEPA, as it is not included on the State of California's Proposition 65 list of chemicals known to cause cancer or reproductive toxicity. (Liebsch and Musso, 2015)

Response:

As stated in Fox (2015), "coal dust" is "an umbrella term that includes the full range of particle classifications based on size, from granules to very small particles." To give an example, raw coal contains many kinds of polycyclic aromatic compounds (PAHs), including both naphthalene and benzo[b]fluoranthene (Zhao et al., 2000), two compounds listed by the State of California's Proposition 65 list (California EPA OEHHA, 2016). PAHs are toxic constituents of PM2.5 that have been shown to have mutagenic, carcinogenic, and asthma-inducing effects (WHO, 2003). Coal dust additionally contains a host of metals and metalloids, including silica, which have been shown to have a negative effect on human health (Colinet, 2010; Epstein et al., 2011; USEPA (U.S. Environmental Protection Agency), 2009a).

More generally, a good portion of blowing coal is documented to be in the fine particle range (i.e., PM2.5). As documented in Chapter 2, the WHO considers $PM_{2.5}$ to be a causal determinant of poor health, including premature mortality:

> *"The 2009 PM ISA synthesized the epidemiologic literature characterizing the association between long-term exposure to PM2.5 and increased risk of mortality and concluded that 'a causal relationship exists between long-term exposure to PM2.5 and mortality' (See Section 7.6 of the 2009 PM ISA). Long-term mean PM2.5 concentrations ranged from 13.2 to 32.0 µg/m^3 during the study periods in the areas in which these studies, comprising the entire body of evidence reviewed in the 2009 ISA, were conducted. When evaluating cause-specific mortality, the strongest evidence contributing to this causal determination was observed for associations between PM2.5 and cardiovascular mortality. Positive associations were also reported betweenPM2.5 and lung cancer mortality."*

"The epidemiologic evidence evaluated in the ISA contributed to the determination that there is sufficient evidence to conclude that 'a causal relationship exists' between short-term PM2.5 exposure and cardiovascular effects and mortality, and a 'likely to be causal relationship exists' between short-term PM2.5 exposure and respiratory effects (Chapter 2, 2009 PM ISA)." (U.S. EPA (U.S. Environmental Protection Agency), 2012)

Comment by coal proponent:

A series of studies conducted in the UK found no association between respiratory diseases and proximity to opencast coal mining sites, suggesting a lack of causality between exposure to coal dust and health effects in children. (Burns, 2015)

Response:

As detailed in the Appendix Chapter 2, findings from the cited studies of communities surrounding opencast mining operations in the UK run counter to an overwhelming preponderance of evidence suggesting a link between particulate matter and a host of respiratory conditions. Recent evidence of the respiratory response to particulate matter ($PM_{2.5}$) includes, but is not limited to: incident asthma in both children and adults (Brauer et al., 2007; Künzli et al., 2009; Leon Hsu et al., 2015; Young et al., 2014), emergency department visits for respiratory conditions (Alhanti et al., 2016; Malig et al., 2013; Strickland et al., 2015), as well as reduced lung function and bronchitic symptoms in children with asthma (Berhane K et al., 2016; McConnell et al., 2003; Neophytou et al., 2016).

The studies in the UK contain a number of troubling methodological issues with respect to defining the control and exposure groups. The two groups were defined solely using distance from mining operations, excluding important determinants of PM_{10} exposure such as topography and wind conditions. Indeed, PM10 levels were higher in one of the control groups relative to the exposed, demonstrating the difficulty of measuring exposure by distance alone. The authors further failed to control for potential confounders of the studied relationship, such as medication. It could be the case that children living near coal mining operations were more likely to be prescribed asthma medications, which would obscure the health impacts of exposure (the study did find that children living close to mining sites visited their general practitioners more often, which could have led to increased prescriptions). Taking into account these shortcomings in the UK studies, along with the vast literature contradicting them, one can conclude that exposure to particulate matter resulting from shipping coal through Oakland would have negative respiratory on those in the surrounding community.

Comment by coal proponent:

Coal mine occupational exposure studies are not applicable to fugitive dust. (Smith, 2015)

Response:

As stated elsewhere in this report, no threshold concentrations have been found for ambient particulate matter below which negative health effects do not occur, such that it is reasonable

that health effects similar to those faced by coal miners will be experienced by workers handling coal at the terminal. The potentially hazardous conditions faced by workers should not be discounted as a harm of the proposed terminal. Occupational dangers include:

- Inhalation of coal dust
- Exposure to diesel emissions, particularly black carbon (Galvis et al., 2013)
- Train derailments (U.S. Department of Transportation Surface Transportation Board, 2011; Vorhees, 2010)
- Coal dust explosions and coal fires (Hossfeld and Hatt, 2005; de Place, 2012; U.S. Department of Energy, 1993)

Comment by coal proponent:

The metal content of coal is minimal compared to background soil levels and risk-based screening levels as defined by the USEPA. (Liebsch and Musso, 2015)

Response:

This argument ignores several residential and industrial risk-based screening levels exceeded by the metal content of raw coal, and moreover does not make mention of CEPA risk-based screening levels (California Environmental Protection Agency, 2004). For instance, the minimum and maximum levels for arsenic in Utah coal are 1-8ppm, which are approximately 14-114 times the residential risk-based screening level suggested by CEPA (.07ppm). These arsenic levels are also higher than the CEPA industrial risk-based screening level of 0.24ppm (Fox, 2015). Table 1 below displays EPA risk-based screening levels and California background soil levels adapted from Liebsch and Musso (2015), as well as CEPA risk-based screening levels.

Table 1 - EPA & CEPA residential and industrial risk-based screening levels

	Uinta Basin Coal							
	Average	Max		CA Soil Backgd	EPA RSL - Res.	EPA RSL - Ind. Soil	CEPA RSL - Res.	CEPA RSL - Ind. Soil
Element	ppm (or mg/kg)	ppm		mg/kg	mg/kg	mg/kg	mg/kg	mg/kg
Sb	0.2	0.9		0.15 - 1.95	39	580	30	380
As	1	8		0.6 - 11	0.68	3	0.07	0.24
Cd	0.1	0.2		0.05 - 1.7	71	980	1.7	7.5
Cr	7	30		23 - 1579	120000	1800000	100000	100000
Co	1.2	3		2.7 - 46.9	23	350	660	3200
Pb	3.6	7.7		12.4 - 97.1	400	800	150	3500
Hg	0.05	0.38		0.1 - 0.90	23	350	18	180
Ni	2.8	10		9 - 509	1500	22000	1600	16000
Se	1.8	3.4		0.015 - 0.43	390	5800	380	4800
Th	3.4	7.9		5.3 - 36.2	0.78	12	--	--
U	0.9	3.1		1.2 - 21.3	230	3500	--	--

Sources: (California Environmental Protection Agency, 2004) (Liebsch and Musso, 2015)

Comment by coal proponent:

Coal trains currently run through Oakland without any noticeable impact on the surrounding community. (Smith, 2015)

Response

Coal is not currently shipped from the Port of Oakland, nor do coal trains move through Oakland with any semblance of regularity. Coal trains often move between Utah and the private Levin-Richmond terminal north of Oakland. The southern route to the Levin-Richmond terminal, which goes through Oakland, is longer and more expensive than the northern route, such that trains passing through Oakland would be incredibly rare (Gutierrez, 2015b). Notably, residents along the northern route to the Levin-Richmond terminal have commented at length about the disruption to their daily living caused by coal trains (Small, 2015). In a 10/2/2015 letter in response to Question #8 from Assistant City Administrator Claudia Cappio's 9/28/2015 memo, Lora Jo Foo of No Coal In Oakland detailed an extensive investigation into coal trains passing through Oakland over the prior year. In her investigation, Ms. Foo spoke to Port of Oakland and Union Pacific officials, all of whom confirmed that coal trains very rarely pass through Oakland. In fact, likely only two trains had passed through Oakland during the prior year, one of which had been mistakenly routed to the Port of Oakland and was immediately removed upon discovery of the misrouting. Ms. Cappio herself stated that evidence of coal trains in Oakland was limited to two sightings (Foo, 2015).

Comment by coal proponent:

The project will create economic benefits including 2400 jobs, half of which will be given to Oaklanders. (Burns, 2015)

Response:

Relative to other alternatives, coal shipping creates few jobs per dollar invested (Kammen, 2013). Moreover, as detailed by Tom Sanzillo and Margaret Rossoff in their submissions for the 9/21/2015 hearing on the Army Base Gateway Redevelopment Project, coal is not an economically viable export, nor will it produce nearly the number of jobs estimated by the developer. From their findings, it can be concluded that better job alternatives to coal exist. Findings were as follows:

- While the entirety of Oakland Global is projected to create roughly 2400 permanent jobs and 2700 construction jobs, the bulk terminal used to ship coal will provide just 5% of total full-time permanent on-site jobs and 6% of construction jobs, a total of 278 jobs that would just as likely be created using the terminal for a different commodity (Rossoff, 2015).

- The developer estimate of 212 indirect jobs created by the bulk terminal is overstated -- amongst other estimation errors, the developer did not account for jobs loss, such as trucking positions that will no longer exist with increased rail transport. Moreover, the indirect jobs created by the terminal would by no means be located in Oakland, the area that would be most negatively impacted by coal.(Rossoff, 2015).

- The coal industry has been dramatically declining for years, meaning that jobs created at the terminal would be constantly in danger. It would be financially reckless for the city to allow devoted resources in the OAB to such an economically weak commodity. Evidence pointing to the weakness of the coal industry includes:
    - Coal producers have seen dozens of firms enter bankruptcy since 2012 (Sanzillo, 2015), including in recent months the largest U.S. producer of coal (Brickley, 2016). Over the past two decades, the percent of U.S. electricity coming from coal has dropped from over 50% to just 34%. Asian demand for coal -- once seen as a life preserver for the industry -- is similarly on the decline, with China's coal imports dropping by roughly 40% from 2013 to 2015. The largest U.S. investments firms almost uniformly conveyed a pessimistic long-term outlook for coal exports (Sanzillo, 2015).

    - Global prices for coal sunk by as much as 75% from 2011 to 2015, dropping far below prices considered to be sustainable by producers (Sanzillo, 2015).

Bowie Resources, the coal producer linked with OBOT, has experienced a declining market share for years, and been hurt by the retirement of many of the coal plants with which it transacts. The fact that the state of Utah is putting up additional capital for the project -- not Bowie Resources parent company Trafigura -- speaks to the total lack of confidence in Bowie Resources to deliver for the full length of their contract. Furthermore, in its own recently filed IPO, Bowie Resources itself indicated that it did not anticipate nearly the level of demand needed to meet throughput targets with its partner ports (Sanzillo, 2015).

Comment by coal proponent:

The coal shipped through OBOT will be "Compliance Coal", which has a low sulfur content and is amongst the cleanest burning coals -- it will replace dirtier coals and biomass burning, actually leading to a net reduction in pollution and climate change. (Bridges, 2015)

Response

As noted by Laura Wisland of the Union of Concerned Scientists in her submission for the 9/21/2015 hearing on the Army Base Gateway Redevelopment Project, while coal with a lower sulfur content is considered to be cleaner, the contribution of coal shipped from OBOT will in no uncertain terms contribute to global warming emissions, for the reasons listed below:

- "Compliant coal" is still harmful for the environment. The ten million metric tons of coal shipped through OBOT each year will result in annual CO_2 emissions of 26 million tons into

the atmosphere, requiring 10 billion gallons of water (Wisland, 2015). CO_2 emissions will exceed 1.5 billion tons over the course of the developer's 66-year lease (No Coal In Oakland, 2015).

- Sub-bituminous coal has a lower BTU content than other coals, meaning more must be burnt relative to other coals to obtain the same amount of energy. This lower energy potential of coal could offset any net gains from its low sulfur content (Wisland, 2015).

A further economic case can be made that shipment of coal from OBOT will lead to higher greenhouse gas emissions, as classic supply and demand theory predicts that the arrival of large amounts of coal on foreign markets will lower its price and increase consumption through "induced demand." Additionally, coal supporters have argued that the presence of a more efficient coal on the market would lead to less demand for dirtier biofuels. This rationalization underestimates the ability of developing countries to replace biofuels with renewable energy sources, which are increasingly available (Wisland, 2015).

Overall, Bridges (2015) is correct in making the assumption that coal is a dirty fuel which must be transitioned away from on the world market, however doing so by simply adding more coal would be counterproductive and harmful to the environment.

Chapter 7: Health and Safety Hazards at the Port

Key Points

1. Coal is inherently challenging to handle and transport. This is because it is (a) combustible in solid form, (b) highly explosive when suspended as particles in confined spaces, (c) toxic to humans especially when inhaled as dust, and (d) noxious to those who encounter its dust.
2. Export of coal through Oakland requires that coal be transferred from the mine site to rail cars, transported by rail over many hundreds of miles to the port facility, transferred from rail cars into the port facility, transferred into storage heaps pending shipment, transferred out of the storage heaps to the wharves, loaded into ships, and then shipped out to the destination. Each step creates opportunities for release of dust and for hazards to adjacent workers, residents, businesses, and communities.
3. Environmental impacts include air pollution, water pollution, solid waste, noise, and safety and traffic hazards. Not all of these issues appear to be addressed in the Basis for Design or related documents.
4. The project area has seismic vulnerabilities that could create hazards in the likely event of an earthquake, as the soils are in highest category for liquefaction.

Findings

1. **Coal is inherently challenging to handle and transport. This is because it is (a) combustible in solid form, (b) highly explosive when suspended as particles in confined spaces, (c) toxic to humans especially when inhaled as dust, and (d) noxious to those who encounter its dust.**

   The adverse traits of coal are acknowledged by the project proponents as noted in the Basis of Design submitted for the Oakland Bulk and Oversize Terminal (OBOT). The document notes that the commodity (described as "A") will be "extremely abrasive, very dusty, exhibit spontaneous combustion behavior, and potentially explosive" (1).

   a. Spontaneous combustion

   Coal is combustible and considered to be "notoriously liable" to spontaneously ignite [8] when transported over long distances or stored (2). The conditions under which this can occur are complex. Because the port area is small, ignition would create health and safety concerns for workers at the port, other businesses, nearby residents, first responders, and critical transportation links such as freeways.

[8] Spontaneous combustion is also referred to as "autogenous heating." This is not the same thing as the explosions that can occur with an accumulation of dust.

In one reported case of spontaneous combustion, two firefighters were killed trying to put out a fire at a coal storage silo in South Dakota. Contributing causes of the explosion and fire according to the report published by the National Institute for Occupational Safety and Health (NIOSH) in the Centers for Disease Control and Prevention (CDC) included the design of the silo, the unique explosive characteristics of bituminous coal, and fire fighting tactics (3).

In its report the National Institute for Occupational Safety and Health wrote:

> *One of the primary concerns for the bulk storage of coal is its ability to produce its own heat. The storage of bulk coal, whether inside a silo or stockpiled on the ground, releases heat slowly through oxidation. It is possible for enough heat to be released over a period of time to raise the coal temperature to self-ignition or spontaneous combustion. Such fires can be very stubborn to extinguish because of the amount of coal involved (often hundreds of tons) and the difficulty of getting to the seat of the fire. Moreover, bituminous coal in either the smoldering or flaming stage may produce copious amounts of methane and carbon monoxide gases. Methane is not a concern with sub-bituminous (PBR) coals.*
>
> *In addition to their toxicity, these gases are highly explosive in certain concentrations, and can further complicate efforts to fight this type of coal fire. Even the most universal firefighting substance, water, cannot always be used because of the possibility of a steam explosion. Water contributes to the exothermic reaction of coal increasing the fire problem.*

b. Explosion

Coal dust can be highly explosive in confined spaces such as mines or closed terminals (4-7). The potential for coal dust explosion is a concern whenever dust may accumulate in enclosed spaces, is not limited to mines (8), and includes shipment and transfer of bulk coal (9). At underground mines, ignition of coal dust is a cause of mine explosions that have killed many hundreds of miners, so rock dust is distributed to reduce the potential explosiveness of coal dust (10) This is not practical at a port.

The size of dust particles matters, as finer particles are more likely to create combustible conditions. There is some suggestion that cleaning and processing of coal tends to create smaller particles (11). While transportation facilities are not likely to experience as high concentrations of coal dust in confined space, they are still noted as a major concern for explosion. The Port of Los Angeles experienced fires during ship loading in 2001 and 2002 attributed to ignition of coal dust (12). A fire was reported on June 6 at a coal-fired power plant in Springield, Missouri in a dust control system and attributed to highly combustible coal (13).

c. Toxicity

Coal dust is a toxic substance that poses health risks when inhaled. Coal dust is well documented to cause extensive health effects and mortality in miners, though at greater concentrations than likely at a port (14-19). One component of coal dust is PM 2.5 (discussed elsewhere) but it can include toxic metals (also discussed elsewhere) and poly aromatic hydrocarbons (20, 21).

d. Noxious and abrasive nuisance

Coal dust is black and tends to be sticky and accumulate on people and property, creating a significant nuisance near coal terminals (22). Residents of areas impacted by coal dust often complain of the nuisance and filth of the particles. Residents of Richmond complain of dust from coal trains and the coal terminal (23). This terminal ships only about 1 million metric tons of coal a year (but accumulates coal in a heap outdoors).

Recent complaints by people living in Mobile about dust from coal terminals led to an investigative report by a local television station that also conducted sampling at various locations and reported significant fractions of coal dust at all places sampled (24, 25).

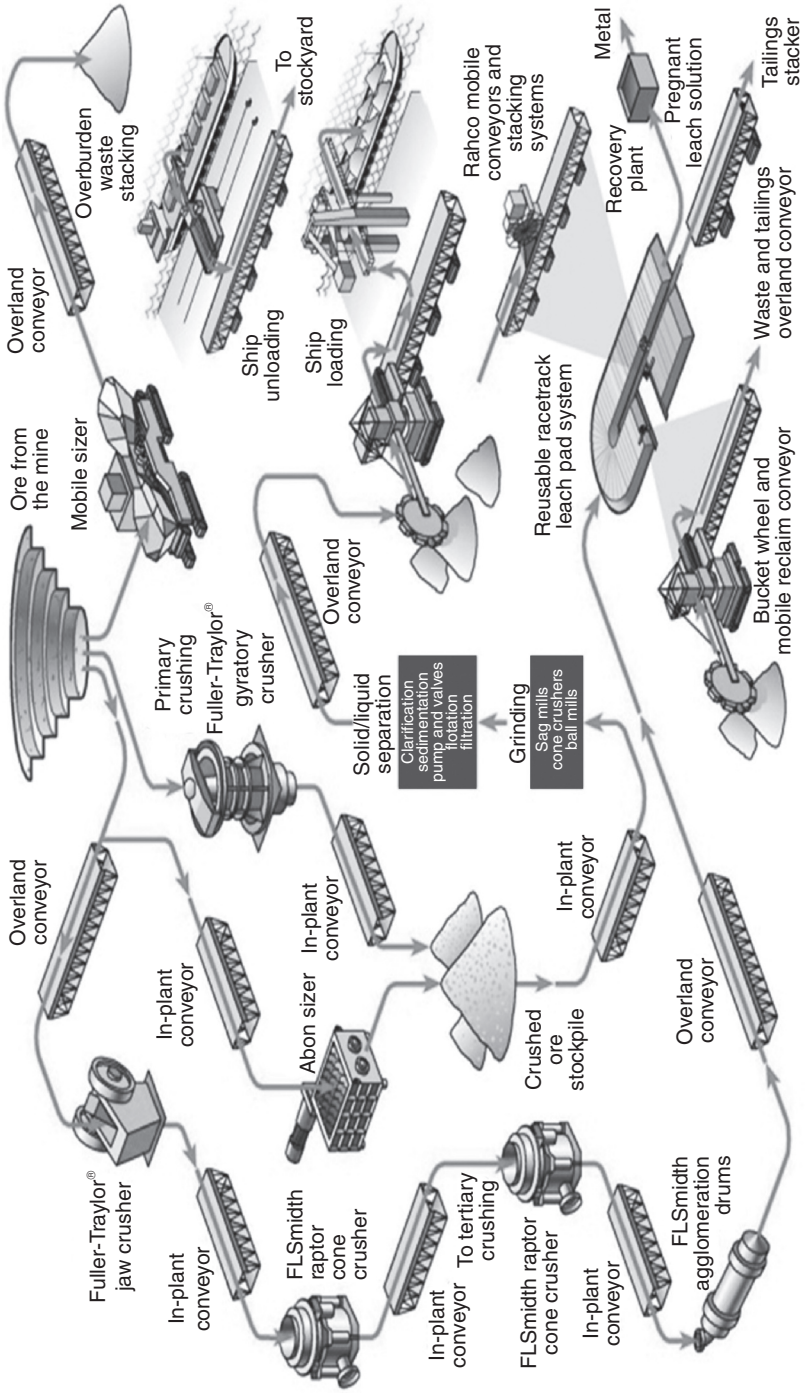
Coal dust is also abrasive and may damage equipment and increase cleaning and maintenance costs. The Surface Transportation Board has determined that coal dust "poses a serious problem for railroad safety and operations" because it accumulates along the rail right of way and damages the infrastructure. The Board recognized that controls on dust are important to protect the interests of the companies that operate railroads and public safety (26, 27).

2. Export of coal through Oakland requires that coal be transferred from the mine site to rail cars, transported by rail over many hundreds of miles to the port facility, transferred from rail cars into the port facility, transferred into storage heaps pending shipment, transferred out of the storage heaps to the wharves, loaded into ships, and then shipped out to the destination. Each step creates opportunities for release of dust and for hazards to adjacent workers, residents, businesses, and communities.

A. Can a coal terminal be fully enclosed?

The project proponents assert that the inherent hazards associated with coal transportation will be managed because the terminal will be constructed and operated as a wholly enclosed facility that will provide for all transfers and storage to be completed in a confined space. Handling of coal through dumping out of the bottom of train cars, loading into storage piles or areas, or conveyance to ships can contribute to generation and distribution of coal dust (28).

Flow chart of coal processing



20.1 Generic flow chart coal handling. (Source: FLSmidth standard flow sheets.)

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The proposal to wholly encapsulate the terminal seems to represent a departure from practice at any other coal terminal that we can identify and so seems to be an unproven technology. Coal terminals typically employ various degrees of covering and dust control but are not entirely contained. We did not identify any coal terminals that operated in contained spaces that prevent release of dust to the ambient environment, nor has the project proponent identified any as far as we have been able to determine.

There appear to be discrepancies between the assertion that the entire terminal will be enclosed and the Basis for Design document offered as substantiation for the project. The Basis for Design provides for movement of coal unloaded from rail cars through conveyers, spreading of coal into horizontal heaps for storage, and overhead loading of coal into ships. None of these things seems to be encapsulated within the enclosed design.

B. Managing coal and coal dust creates hazards

The handling of coal dust is an on-going and significant concern as long as coal is transferred through the port, regardless of whether the facilities are contained or not. There may be tradeoffs in terms of infrastructure between allowing more ventilation of coal and of coal dust, which will tend to increase the distribution of dust into the environment but reduce the potential for explosion compared to the containment of coal. If coal and dust is contained in confined spaces, there is potential for suspension of coal dust in the air, which can be explosive and ignited by spark, static electricity, or heat. Coal dust explosions are of course extremely dangerous for workers, emergency responders, and the nearby community.

Either way, introduction of the noxious materials into a highly used area in the immediate vicinity of West Oakland neighborhoods, recreational facilities, and highways, very close to the downtown of a major city and cultural center, will require effective management.

Design of facilities to ensure a level of dust reduction necessary to meet environmental standards and address public health concerns is identified as a major challenge for development of coal ports (2, 29). Primary prevention strategy would be to prevent the generation or accumulation of the dust. Secondary mitigation strategies try to control the dust through ventilation or dust removal (30) as proposed for this project.

C. Dust control through air filters creates potential for fire and requires active management

The documents provided by the project sponsor acknowledge the importance of ensuring that conditions amenable to combustion do not occur. They say that extensive spraying of coal will be conducted to control dust and reduce the likelihood of explosion. The project proponents assert that they will eliminate dust hazards through use of air filtering technologies. However, these actions are not without alternate persistent hazards. Air filtering technologies can contribute to

explosive ignition of coal dust if not actively and competently managed on a daily basis.

Though there are some preliminary indications of types of equipment that may be used and mention of the use of both dust filters and wetting as strategies for dust control from the project proponents, as far as we can determine, no safety analysis has been conducted for the potential transfer of bulk coal through OBOT.

The design of conveyances to achieve performance and other goals including environmental goals needs to consider the specific factors at each installation and the materials being used and so cannot be guaranteed without site specific design and subsequent performance verification and testing (29). This means that assurance of performance capacity of any system cannot be guaranteed at an early design stage and health and safety review and verification is needed up to the point of operation. They may not be suitable for urban areas such as Oakland.

The Basis of Design submitted by the project proponent states that railcar dumpers will be used at the facility with a bottom dump. The rail cars would be North American Covered Hopper Cars. These are denoted as removable, fiberglass covers (1). However, in searching for such a car used for coal, no examples were found. North American Covered Hopper Cars are described by GATX, a major purveyor, as being of three types and used for several types of materials but not for coal (31). Additional discussion of this issue appears elsewhere in this submittal.

Conveyors tend to release dust and so have health and safety concerns, especially in an area prone to wind. While the Basis of Design document discusses the use of Pipe Conveyers, which are less prone to emit dust, for transfer from the railcar dumper to storage, other types of belt conveyers are to be used at other phases of the transfer including moving the coal to storage.

We did not identify many coal terminals in such close proximity to dense urban environments as downtown Oakland or critical infrastructure as the Bay Bridge. The Long Beach coal terminal is located at the far southern end of the Port of Long Beach away from freeways and critical infrastructure and areas of dense housing. The prevailing winds would tend to push dust out over the water rather than into downtown Long Beach. Moreover, this facility was grandfathered in and has never received an environmental review. Nearby residents complain of dust. Some areas have rejected construction or expansion of coal terminals in recent years including most recently the rejection by the US Army Corps of Engineers of the Gateway Project near Bellingham Washington (32).

3. **Environmental impacts include air pollution, water pollution, solid waste, noise, and safety and traffic hazards. Not all of these issues appear to be addressed in the Basis for Design or related documents.**

The environmental impacts of coal transportation include air pollution, water pollution, solid wastes, noise levels, and safety and traffic hazards (36). The OBOT response to the City on September 28, 2015 states that no environmental review is required because the project will comply with numerous air and water quality regulations**.** However it does not appear that all issues will be addressed through existing regulations and reviews.

a. **Use of Water and Generation of Contaminated Process Water and Wastewater**
   Demands for water appear to be significant and may conflict with the demands for water from the community of Oakland, creating health impacts.
   The documents provided by the project sponsor say that extensive spraying of coal will be conducted to control dust and reduce the likelihood of explosion. Application of water to the coal will generate significant wastewater contaminated with coal dust containing toxic fractions that then have to be managed. Any release of water contaminated with constituents of coal dust or the disposal of sludge associated with the treatment of such wastewater can introduce toxic elements into aquatic food chains that support human consumption of fish and wildlife and contribute to health effects.

   The plans for disposal of process water are not specified. There would be an onsite treatment facility for circulation or discharge. Such a discharge would presumably require an NPDES wastewater treatment permit and trigger CEQA review.

   Raw coal dust emission sources to marine ecosystems include preparation and washing of coal, loading operations, runoff from storage areas, transport and cargo washing, and accidental releases (37). Coal terminals have been found to contribute to accumulation of coal dust particles in the surrounding marine waters, and these particles can disperse over a significant area, creating risks to aquatic species and ecosystem (38). Raw un-combusted coal contains PAHs, some of which can be toxic. High volatility, bituminous coal (such as that from Utah) has been reported to have relatively higher concentrations of the PAHs that are considered Priority Pollutants by the US EPA (39). The types of PAHs found in coal varies by type, “rank,” and basin of origin (40). One study reported that PAHs are much more concentrated in raw coal than in coal ash (after combustion) (20). Raw coal contains PAHs that may be harmful to marine organisms (37). There is emerging evidence of the effects of coal particles and dusts on wildlife and biota (41, 42). A study on mice using exposure to sand contaminated with coal dust reported effects on several types of assays and diminished lung function (43). A study of a Colombian coal terminal found accumulation of certain PAHs and metals along the shoreline, and assays suggested possible effects on exposed species (44).

   Any plans needed for removal and treatment of ballast water from the incoming ships are not included here.

b. Full Site Assessment and Response

The Basis of Design document states that the project proponents will not do any site assessment for hazardous materials nor be responsible for any materials present. It would be important for some entity to be responsible for this. There are references to assessments conducted by the Department of Toxic Substances Control, but it appears that the City assumed the responsibility and liability for areas and contaminants not to be addressed in those plans. Some clarification of what approach would be taken would be important.

c. Noise

Noise is a significant issue for conveyance equipment when located near an urban environment or adjacent to a neighborhood (45). Noise remains a concern and is not addressed in the Basis for Design.

c. Air Pollution Control

The OBOT response to the City on September 28, 2015 notes that one action will be taken to reduce exposure to particulate matter for indoor spaces. Several possible actions are discussed, and it is impossible to determine whether this would benefit adjacent workers or residents.

The OBOT response to the City on September 28, 2015 states that common exterior spaces will be shielded from air pollution, but given the small size of the available land parcel this does not appear to be meaningful. In any case, buildings do not stop air pollution. Additional mitigation measures are discussed with regard to offsetting PM 10 emissions. Project proponents do not seem to be aware of health concerns with PM 2.5 particulate matter emissions, as the smaller particles that can penetrate deeper into the lungs and that may cross over into the blood stream. This issue is discussed elsewhere.

In their September 2015 report, the consultants to the project proponents assert that no air quality impacts will occur and the permitting process of the Bay Area Air Quality Management District (BAAQMD) will address any dust or air pollution concerns and ensure compliance with requirements for Best Available Control Technology (BACT). With regard to defining BACT for coal dust emissions, we have not been able to identify any applicable rules for BAAQMD. From the Richmond case, it appears there are no rules applicable to coal terminals (23).[9, 10]

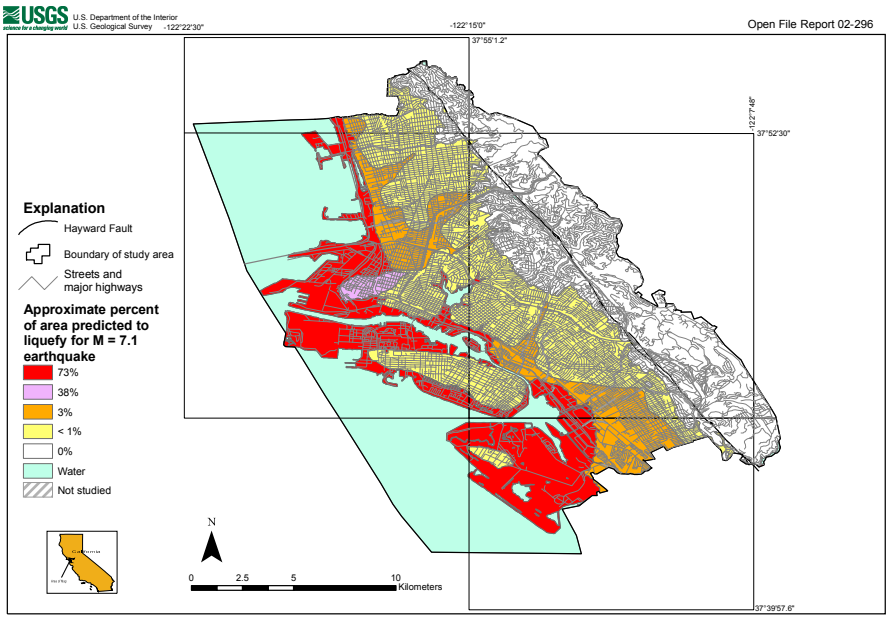
It is also important to understand that there is no guarantee that sufficient technology exists to eliminate or significantly reduce the health impacts or risks.

[9] By contrast, the South Coast Air Quality Management District, which has jurisdiction over Los Angeles, does.
[10] At the European Commission, a document defining BAT for storage of solid commodities has been defined and includes these elements that do not seem to be addressed in the documents submitted by and for the OBOT group include consideration of the layout and placement of facilities, control of wind exposures, and attention to maintenance of good practices over time (46).

Few if any terminals are located adjacent to a densely populated city as Oakland so where would such technologies have been perfected? It can be possible to apply BACT and yet still have emissions that are detrimental to health in cases when sufficient technological controls have not been developed. This can particularly be true when a community is already heavily impacted by air pollution and where the many dust-generated activities with be conducted immediately adjacent to recreational activities and facilities, other businesses, and residences.

4. The project area has seismic vulnerabilities that could create hazards in the likely event of an earthquake, as the soils are in highest category for liquefaction.
   One additional safety concern is the seismic instability of the area where the facility is to be built. As noted in the Basis of Design document (1), existing soils in the project area are prone to seismic-induced liquefaction and lateral spreading. This area has been designated as being of the highest category of risk for failure due to earthquakes in the greater Bay Area (46). Often systems failures occur when multiple unfortunate events occur at the same time, and earthquakes can be a precipitating event. The proposed remedy seems to be to replace soils adjacent to the wharf areas but not other areas. This may warrant additional scrutiny.

Liquefaction Map Including Oakland



Liquefaction Hazard Map of Alameda, Berkeley, Emeryville, Oakland, and Piedmont, California: A Digital Database
by
Thomas L. Holzer, Michael J. Bennett, Thomas E. Noce, Amy C. Padovani and John C. Tinsley, III

Chapter 8: Climate Change and Health and Oakland

Key Points

Climate change implications of coal shipments through Oakland are important to consider for these reasons:

- The overseas combustion of coal from Oakland will contribute to cumulative global greenhouse gas concentrations and climate change.
- The export of coal from Oakland thus increases the risk of serious health and safety harms from climate change for the residents of Oakland, and constitutes a substantial health hazard.
    - Climate change is the greatest health challenge of this century, and is a significant threat to the health and safety of Oakland residents.
    - Extreme heat and increased ozone resulting from climate change and increased exposure to particulate matter from the smoke of more frequent and severe wildfires in California will increase death and illness in Oakland.
    - Sea level rise, higher storm surges, and more extreme precipitation events will increase risk of flooding that can cause displacement, loss of essential infrastructure, and trauma-related death, injury and mental health problems. An estimated 3,100 to 5,200 Oakland residents will be at greatest risk.
    - Increases in the frequency, duration, and magnitude of drought will threaten water quality and potentially lead to severe water shortages, increasing spread of infectious and vector-borne diseases, poor hygiene, and impairment of the water infrastructure essential to support Oakland's growing population.
- Low-income communities and communities of color are at highest risks of adverse health impacts associated with climate change.
- Not shipping coal from Oakland is a reasonable and effective method of preventing associated greenhouse gas emissions and health impacts.

Findings

For the sake of clarity, details and citations to primary sources are included in an immediately following addendum, indexed in the present text for easy reference.

1. **Climate change is the greatest public health challenge of the 21st century. If climate change continues to progress, it will cause significant adverse impacts on the health of people in Oakland, including:**
    a. Higher overall temperatures, more extreme heat days, and more heat waves will increase heat-related mortality and morbidity. *(Addendum 1.3.1, 1.3.4, 25, 35.2)*
    b. Increased ground level ozone and smog formation will lead to increased respiratory and cardiovascular mortality and morbidity, especially in areas already experiencing high levels of pollution. *(Addendum 1.3.5, 26, 35.3)*
    c. Sea level rise and storm surges will produce flooding, especially in areas of Oakland that are low-lying or have dilapidated infrastructure, resulting in various adverse health and safety impacts, as well as displacement and job loss. *(Addendum 21, 27)*
    d. Decreased quality and availability of food will increase risk for food insecurity and malnutrition, especially among the poor. *(Addendum 24, 27.2, 30)*
    e. Increased air pollution from wildfires will increase respiratory and cardiovascular illnesses. *(Addendum 20, 31)*
    f. Increased pollen production, and the length of the pollen season will increase asthma. *(Addendum 1.3.4, 15.1, 26.2, 33)*
    g. Changes in temperature and precipitation patterns may lead to an increase of vector-borne and water-borne infectious diseases in the Bay Area. *(Addendum 22, 28, 30.2, 34*)
    h. West Oakland residents are particularly vulnerable to the health impacts of climate change, rising sea levels, and other phenomena associated with greenhouse gas emissions. *(Addendum 1.3.4, 1.3.6, 1.3.7, 19.2, 21.4, 21.5, 25.2, 27.1, 35)*
2. **At this point in history, there is a narrow window during which actions can be taken to limit climate change and prevent these damaging effects on health.**
    a. Holding temperature rise at or below 1.5°C is critical for averting the worst of the projected exposure risks and impacts of climate change. *(Addendum 2.2)*
    b. Because greenhouse gas emissions accumulate, human activities (mostly by the richer countries) have already emitted most of the greenhouse gases that can be released for the next several thousand years without exceeding the 1.5°C threshold. *(Addendum 5)*
    c. After 2015, there remains for the entire world a "carbon budget" of only 240 billion metric tons of CO_2 emissions for a 66% chance of limiting global

temperature rise to 1.5°C.[11] If this budget is exceeded, there is significant danger that global temperature will rise above 1.5°C. *(Addendum 5.)*

3. **Shipping large quantities of coal from a bulk commodities terminal in Oakland will contribute to the progression of climate change, and the local health consequences of that progression in part would be fairly attributed to Oakland's actions.**
    a. The prevention of severe health harms requires alignment of every level of government with the greenhouse gas reductions needed to meet the global carbon budget and consideration of the climate change consequences at every decision point. *(Addendum 6, 9, 10, 13)*
    b. Rapidly and dramatically reducing greenhouse gas emissions is required to stay under the 1.5°C threshold and prevent severe climate change heath impacts for the people of Oakland. *(Addendum 3.3, 5.4)*
    c. However, the tonnage that could be shipped through Oakland over the 66-year term of lease with OBOT would consume a significant fraction – 0.6% – of the entire world's remaining "carbon budget." *(Addendum 5.1-5.3, 9.1-9.4)*
    d. Further, the CO_2 that will be generated by burning coal shipped through Oakland will also be substantial in relation to California's climate goals. California has set goals to reduce statewide annual carbon emissions to 431 million metric tons of CO_2 equivalent ($MMTCO_2e$) by 2020 and 259 $MMTCO_2e$ by 2030. *(Addendum 9.4.3)* But each year, the coal passing through Oakland could produce 22 million metric tons of CO2 emissions, fully 5.2% of the state's entire annual budget for greenhouse gas emissions in 2020 and 8.5% of its budget for 2030. *(Addendum 9.4.3)* California does not count overseas emissions in its carbon budget, but, when it comes to climate change, the health and environmental exposure consequences are the same whether coal is burned in California or shipped overseas to be burned. *(Addendum 10.1)*
4. **In contrast, prohibition of the transport, storage and handling of coal in Oakland is a reasonable and effective way to prevent the proposed coal from ever being burned, and will thereby contribute to limiting future global greenhouse gas emissions, climate change, and local adverse health effects. *(Addendum 13)* There is strong evidence that much of the coal that would arrive in Oakland would not be shipped and combusted at all, absent the availability of OBOT. *(Addendum 13.3)***

[11] The IPCC calculated the total remaining amount of carbon dioxide that can be emitted in the future for various probabilities of staying within the 1.5°C limit (33%, 50%, 66%). (See Table 1) Given the potential gravity of the consequences of passing 1.5°C, the carbon budget referred to in this chapter is based on the IPCC calculation of the limit on total emissions with a 66% chance of success, rather than 50%, which would reflect the same odds as a coin toss. At the current rate of 40 million metric tons per year, the 400 million metric tons for a 66% chance of success *after 2011* has already been reduced to 240 million metric tons *after 2015*. *(Addendum 5)*

Addendum

Cumulative Emissions and Carbon Commitments

1. Climate change is the greatest threat to health facing the world.

1.1. The World Health Organization (WHO) calls climate change the greatest threat to global health in the 21st century. (WHO, 2016) The U.S. Global Change Research Program (USGCRP), mandated by Congress in the Global Change Research Act of 1990, states that "[c]limate change is a significant threat to the health of the American people." (USGCRP, 2016.)

1.2. California's legislature identified climate change as a serious health and safety issue when it enacted the landmark Global Warming Solutions Act of 2006 (AB 32) which became part of the State's Health and Safety Code. (Health & Safety Code § 38500.)

1.3. GHG emissions are cumulative over time and across sources – every source contributes to global temperature change and local exposure and impact (Allen, 2009a, b). As detailed later in the Addendum, Oakland may experience climate-change-induced health impacts including:

1.3.1. The number of extreme heat[12] days in Oakland will increase: assuming a "high GHG scenario," 2017 is projected to have 28 extreme heat days, up from 4 anticipated in 2016. (City of Oakland, 2016a) Statewide, heat waves will increase 2-4 fold, resulting in a 2-6 fold increase in heat-related deaths (California Climate Change Center, 2012)

1.3.2. Mortality in Alameda County may increase 9.8% for every 10° F change in mean daily temperature, with an excess mortality risk of 5.1% for people > 65. (Ostro, 2011)

1.3.3. Respiratory and cardiovascular hospital admissions in Alameda County may increase 2.6% and 1.4% per 10°F increase in mean daily temperature. (Ostro, 2011)

1.3.4. Oakland, considered the city most vulnerable to extreme heat in the Bay Area, (California Energy Commission, 2012) will likely also see an increase in asthma and acute respiratory distress, hospital visits, lost school days, pre-term births, heat stress, and allergy duration and intensity due to rising temperature. (USGCRP, 2016)

[12] The State of California defines an extreme heat day as a day during the months of April through October, where the maximum temperature exceeds (in Oakland) 81 degrees Fahrenheit, and defines a heat wave as five or more consecutive extreme heat days. The projections for Oakland are based on the 98th historical percentile of max temperatures based on daily temperature maximum data between 1961-1990. See Cal-Adapt website http://cal-adapt.org/temperature/heat/#. Extreme heat conditions can result in heat stroke, heat exhaustion and cardiovascular stress and there are greater risks for the elderly and children. (City of Oakland, 2016a)

1.3.5. Rising temperatures due to greenhouse gases can cause excess mortality associated with ozone and particulate matter exposure. Excess annual air pollution deaths due solely to GHG-related temperature rise may reach roughly 600 PM2.5-attributable and 400 ozone-attributable deaths in the U.S. per 1°C increase. (Jacobsen, 2008)

1.3.6. An estimated 3,100-5,200 Oakland residents[13] are at risk of flooding in coming decades due to higher storm surges, extreme precipitation events, and sea-level rise. (Pacific Institute, 2014) Likely effects of these scenarios include traumatic injury and death, mental health disturbances (anxiety, stress-related trauma), increased infection and communicable disease, displacement, and disrupted access to safe food, water and essential services. (City of Oakland, 2016a; Pacific Institute, 2014)

1.3.7. While the health impacts of climate change affect all Oakland residents, those of West Oakland, especially in neighborhoods adjacent to the former Oakland Army Base, and those in the flatlands of East Oakland are at increased risk for harmful effects and for more severe consequences due to preexisting health conditions, higher exposure to environmental hazards, social, economic and demographic factors, and limited adaptive capacity. (CA Energy Commission, 2012)

1.4. "Climate change is a medical emergency," according to the Lancet Commission on Health and Climate Change. "It thus demands an emergency response…." (Lancet Commission on Health and Climate, 2015)

2. Global temperature rise will drive health effects of climate change

2.1. Planetary and health effects of climate change at a 2°C rise are severe. For over a decade, the 2.0°C mark has been criticized for inappropriately accounting for climate dynamics – "with disastrous consequences." (Hansen, 2005; 2013) Its validity as a safety threshold has been widely challenged. (Tschakert, 2015)

2.2. Holding temperature rise at or below 1.5°C is critical for averting the worst of the projected exposure risks and impacts of climate change. (UNFCCC, 2015) Significantly, in a 1.5°C scenario, after the year 2100 many climate impacts begin to reverse, while at 2.0°C, they increase or accelerate. (Schleussner, 2016)

2.3. The 2015 Paris Agreement partially responded to the 1.5°C imperative: "Recognizing that climate change represents an urgent and potentially irreversible threat to human societies and the planet," the 2015 Paris Agreement aims to hold the increase in the

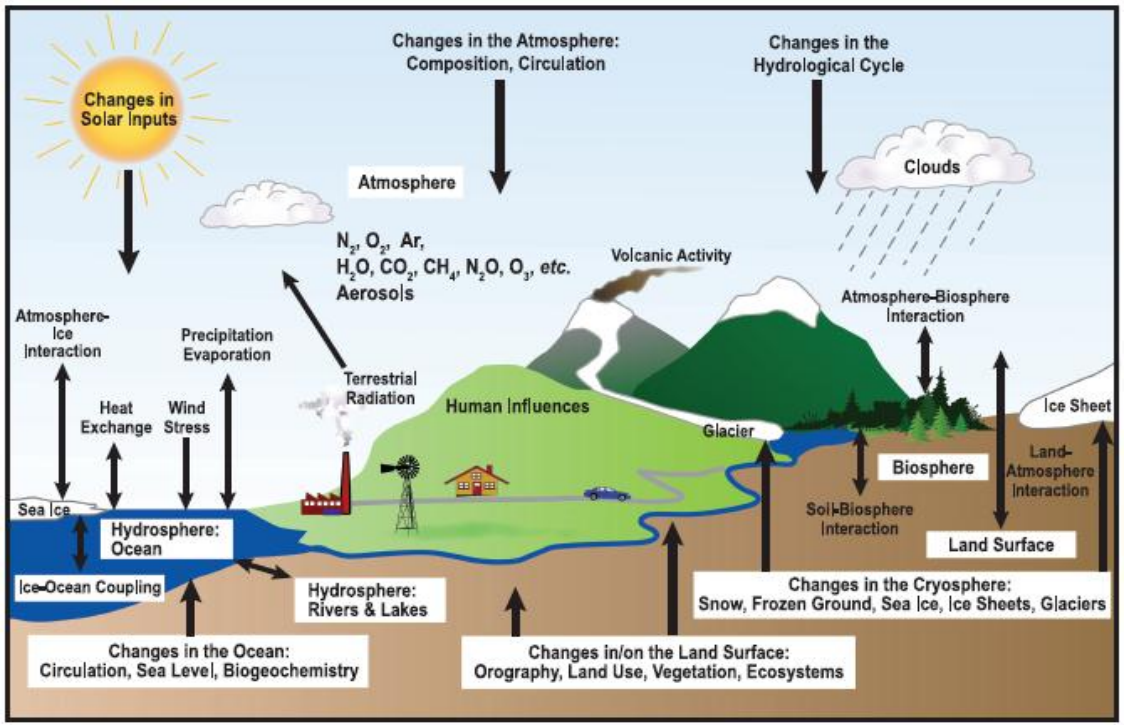
[13] Oakland residents living in West Oakland, China- town, San Antonio, Fruitvale, Central East Oakland, and Elmhurst districts will experience the most exposure to flooding in the future. (Pacific Institute, 2014)

global average temperature "to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C." (UNFCCC, 2015)

3. Effective prevention of any level of temperature rise requires targeting its root cause: the increase in concentration of greenhouse gases in the earth's atmosphere.

3.1. The number one cause of climate change is the burning of fossil fuels—coal, oil, and natural gas. (EPA, 2016e) Their combustion releases greenhouse gases (GHGs) that warm the Earth by trapping heat in the earth's atmosphere (Figure 1).[14]

Figure 1 Components of the climate system



Source: Intergovernmental Panel on Climate Change (IPCC), Climate Change 2007: The Physical Science Basis", Cambridge University Press, 2007, page 104.

3.2. Carbon dioxide (CO_2) is the primary GHG driving climate change, accounting for 81% of GHGs. (EPA, 2016b) Long-term temperature change remains primarily associated with total cumulative CO_2 emissions. (Mathews, 2012)

3.3. According to the IPCC Fifth Assessment Report, mitigation, in the context of climate change, means human intervention to reduce the sources or enhance the sinks of GHGs. (IPCC, 2014)

[14] The principal greenhouse gases—carbon dioxide, methane, and nitrous oxide—have increased to levels unprecedented in the last 800,000 years. (IPCC, 2013c; USEPA, 2016f) Atmospheric carbon dioxide concentrations have increased over 40% since pre-industrial times, primarily from fossil fuel emissions and secondarily from net land use change emissions. (IPCC, 2013b, c; USEPA, 2016f)

4. **However, individual sources and annual levels of emissions cannot be seen in isolation; the cumulative effect of GHG emissions drive climate change (and its health impacts).**

   4.1. Once emitted, much of the CO_2 remains in the atmosphere for many thousands of years before natural processes reduce its concentration.[15] (Archer, 2009) There is no known safe and effective way to remove greenhouse gases from the atmosphere on a global scale. (Royal Society, 2009)

   4.2. Therefore the magnitude of warming that we experience is not determined by "emissions in any one year, but by cumulative CO_2 emissions produced over time." (Davis and Socolow, 2014)

   4.3. Further, the magnitude of climate change is largely driven by the amount of greenhouse gases emitted globally (EPA, 2016b; Allen, 2009a,b); each new source of emissions must be considered in the global context of *all* current and future emissions and their cumulative, or aggregated, impacts. "[C]hoices made now and in the next few decades will determine the amount of additional future warming." (USGCRP, 2014) Regardless of where combustion occurs, the resultant emissions contribute to global changes in temperature and other climate impacts.

5. **Based upon the cumulative dynamics of CO_2 emissions, the Intergovernmental Panel on Climate Change has clarified that all emissions draw from a singular global "climate budget." which is the amount remaining for humanity to emit before reaching a CO_2 concentration that corresponds with a global temperature rise (e.g., 1.5°C). Exceeding this budget and thereby surpassing 1.5°C is irreconcilable with the continuation of the world's current natural systems and human societies.**

   5.1. The Intergovernmental Panel on Climate Change (IPCC) has estimated that, in order to have a 66% chance of keeping global temperature rise at or below 1.5°C, humanity's total cumulative CO_2 emissions after 2011 for the next several millennia must not exceed 400 billion metric tons (Table 1). (IPCC, 2013b; Allen, 2009b)

[15] The ocean equilibrates to capacity with atmospheric CO_2 (Archer, 2009) and has absorbed about 30% of the emitted anthropogenic carbon dioxide, causing ocean acidification. (IPCC, 2013) The 20-40% of CO_2 remaining in the atmosphere takes much longer to process or equilibrate, meaning the "climate effects of CO_2 releases to the atmosphere will persist for tens, if not hundreds, of thousands of years into the future." (Archer, 2009)

Table 1 Cumulative carbon dioxide emissions consistent with limiting warming to less than the stated temperature at different levels of probability, as calculated by the IPCC.

Cumulative CO_2 emissions from 1870 in $GtCO_2$									
Net anthropogenic warming [a]	<1.5°C			<2°C			<3°C		
Fraction of simulations meeting goal [b]	66%	50%	33%	66%	50%	33%	66%	50%	33%
Complex models, RCP scenarios only [c]	2250	2250	2550	2900	3000	3300	4200	4500	4850
Simple model, WGIII scenarios [d]	No data	2300 to 2350	2400 to 2950	2550 to 3150	2900 to 3200	2950 to 3800	n.a. [e]	4150 to 5750	5250 to 6000
Cumulative CO_2 emissions from 2011 in $GtCO_2$									
Complex models, RCP scenarios only [c]	400	550	850	1000	1300	1500	2400	2800	3250
Simple model, WGIII scenarios [d]	No data	550 to 600	600 to 1150	750 to 1400	1150 to 1400	1150 to 2050	n.a. [e]	2350 to 4000	3500 to 4250
Total fossil carbon available in 2011 [f]: 3670 to 7100 $GtCO_2$ (reserves) and 31300 to 50050 $GtCO_2$ (resources)									

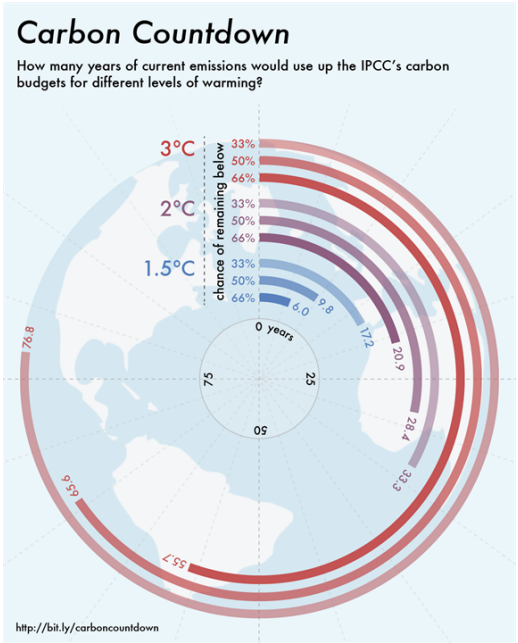
Source: Table 2.2 of IPCC, 2013b

5.2. Since 2011, global emissions have averaged approximately 40 billion metric tons per year (Rogelj et al., 2016), consuming about 10% of the budget each year.

5.3. At this rate, only 240 billion metric tons of the budget remains after 2015 and the entire post-2011 400 billion metric ton budget will be used up in less than six years. (Figure 2) (Carbon Brief, 2015)

5.4. Stringent early reductions in greenhouse gas emissions will slow cumulative impacts and are "key to retain a possibility for limiting warming to below 1.5°C by 2100," and "the window for achieving this goal is small and rapidly closing." (Rogelj et al., 2015)

Figure 2 Illustration of the remaining global carbon budget by temperature scenarios, starting at 2105



Source: Carbon Brief, 2015. Infographic at http://www.carbonbrief.org/six-years-worth-of-current-emissions-would-blow-the-carbon-budget-for-1-5-degrees); data at http://bit.ly/carboncountdown (accessed June 11, 2016).

6. **Action at the local, regional, and state level therefore must be directed toward staying within global limits on cumulative CO_2 emissions if we are to avert the most negative health and safety consequences of climate change. Frameworks for doing so already exist.**

   6.1. To align with a global carbon budget, local decisions must be made within the context of global cumulative and aggregate emissions.

   6.2. California law already provides a framework for decision-making on a cumulative basis. When interpreting CEQA, the California Supreme Court recognized that, "because of the global scale of climate change, any one project's contribution is unlikely to be significant by itself. The challenge for [environmental] purposes is to determine whether the impact of the project's emissions of greenhouse gases is *cumulatively* considerable, in the sense that 'the incremental effects of [the] individual project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects.'" (California Supreme Court, 2015).

   6.3. Internalizing the cumulative direct and indirect impacts of a decision or action is an established element of several economic and environmental frameworks, including true cost accounting (environmental full cost accounting) (Steffan and Burritt, 2000), GHG Protocol Product LifeCycle Accounting and Reporting Standard (The Product Standard) (Greenhouse Gas Protocol, 2011), Consumption-based Accounting (Davies and Caldeira, 2010) and Commitment Accounting, a method to inform public policy by quantifying future emissions implied by current investments. (Davies and Socolow, 2014; NCIO 2015).

      6.3.1. "Commitment accounting of CO_2 emissions provides critical information about future emissions related to infrastructure that currently exists or might be built. Reducing CO_2 emissions will ultimately mean retiring CO2-emitting infrastructure more quickly than it is built… By revealing the emissions that are anticipated decades into the future, commitment accounting of CO2 emissions may help to integrate analyses of capital investment, cumulative emissions, and damages from climate warming." (Davis and Socolow, 2014)

7. **Oakland's existing policy and contractual obligations already support accounting for the total cumulative emissions associated with its decisions.**

   7.1. Oakland's Energy and Climate Action Plan of 2012 already supports accounting for total emissions in its stated purpose, which is to "identify and prioritize actions the city can take to reduce energy consumption and greenhouse gas emissions <u>associated</u> with Oakland." (City of Oakland, 2012) This formulation does not limit its scope to emissions occurring within the city line.

7.2. The Development Agreement between the City of Oakland and the Developer regarding the "Gateway Development / Oakland Global" states in section 3.4.2 that the City's police powers extend to not only current but also future users and neighbors of the project. (City of Oakland, 2013) By including this express provision in the Development Agreement, the City has acknowledged accountability for the impacts its decisions today will have on the circumstances faced by future residents and workers.

8. Globally, one of the most important carbon commitments to address on a cumulative basis is the combustion of coal. Coal-fired power plants are a leading source of CO_2 emissions; coal combustion causes more than 40% of the world's carbon emissions. (Center for Climate and Energy Solutions)

8.1. "Current frontline stockpiles of hydrocarbons – of oil, coal, and gas – are multiples of what could possibly be consumed this century if the climate is to be kept under control… All but the firmest responses leave the door wide open to catastrophic risks and threats to the planet's ability to support life." (DARA, 2012)

8.2. China, India, Indonesia and Vietnam account for three-quarters of new coal-fired power plants scheduled to be launched in the next five years. (Global Coal Plant Tracker, 2016)

8.3. In an address to government and corporate leaders in Washington DC this May, World Bank President Jim Yong Kim declared that, "…if the entire region implements the coal-based plans right now, I think we are finished. That would spell disaster for us and our planet." (Goldenberg, 2016)

9. Oakland faces the prospect of making a massive commitment to coal-related GHG emissions, on a scale that blows past any emissions target previously conceived. If Oakland permits this coal to be shipped, the emissions associated with this decision will be measurable on a global scale, substantial in impact, subversive of the collective initiative to limit GHG impacts to tolerable levels, and associated with climate-related health impacts in Oakland.

9.1. Building an export terminal designed to send up to 9 million metric tons per year[16] of coal to Asian export markets for the next 66 years (the length of OBOT's lease) is a massive carbon commitment that would add as much as 1.46 billion metric tons of CO_2 to Earth's atmosphere. [17]

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[16] The July 16, 2015 Basis of Design submitted by the developer in September 2015 reported 9 million metric tons (9.9 million short tons per year) as the design capacity of the terminal. The developer claims a vested right to use the terminal to ship any lawful commodities—including coal—in any proportion. Accordingly, the calculations in this chapter, like those in the report submitted in September 2015 by Dr. Phyllis Fox, assume shipments of 9 million metric tons per year of coal.

[17] Burning a short ton (2000 pounds) of bituminous coal produces 4,931.30 pounds of CO_2. (United States Energy Information Agency (EIA). 2016) Thus, each unit of mass of coal produces 4,931 ÷ 2,000 = 2.466 units of mass of

9.2. 1.46 billion metric tons is a substantial amount of CO_2 – representing 0.6% of humanity's entire remaining budget of fossil fuel emissions for a (66%) chance of keeping global warming to less than 1.5°C.

9.3. All over the planet, people and their governments are making decisions on the use of coal. If only a small portion of the decisions lead to similar amounts of consumption, then humanity would exceed the limit that is the best chance of protecting the health and safety of Oaklanders and people throughout the world.

9.4. In annual terms, burning 9 million metric tons of OBOT coal each year will result in annual emissions of about 22 million metric tons of CO_2 equivalent ($MMTCO_2e$). This amount alone is equivalent to:

9.4.1. 20,000 times BAAQMD's proposed 1,100-ton threshold of significance under CEQA; (Bay Area Air Quality Management District, 2011)

9.4.2. more than 140% of the total GHG emissions (15.5 MMT) of the Bay Area's five oil refineries. (Bay Area Air Quality Management District, 2015);

9.4.3. a substantial portion – 5.2% – of the *statewide* 2020 annual emissions target of 431 $MMTCO_2e$ and 8.5% of the 2030 emission target of 259 $MMTCO_2e$. (CARB, 2015b; CARB, 2015c)

9.5. If California were required to count the 22 $MMTCO_2e$ that would be generated by burning 9 MMT of coal overseas each year, it would add substantially to the difficulty of meeting its 2020 and 2030 goals.

10. 1.5 billion metric tons of CO_2 will have a discernable effect on global climate, which will be associated with adverse health impacts in Oakland.

10.1. From the standpoint of public health and safety, the climate change exposures and consequential public health impacts of burning fossil fuels in California or overseas are identical. Greenhouse gases affect climate change equally regardless of where they are emitted, and thus they are truly global pollutants.[18] (USEPA, 2016g)

11. Failing to curtail cumulative GHG emissions through "stringent and early reductions" will endanger health and safety in Oakland.

CO_2. Each metric ton of coal produces 2.466 metric tons of CO_2. Burning 9 million metric tons of coal each year will, therefore, produce 22.19 million metric tons of CO_2 per year. Over the 66 year period of the OBOT lease, the cumulative emissions attributable to coal passing through Oakland would be 22.19 million x 66 = 1.46 billion metric tons of CO_2.

[18] As air moves around the world, greenhouse gases become globally mixed, which means the concentration of a greenhouse gas like carbon dioxide is roughly the same no matter where you measure it.

11.1. The Lancet Commission on Health and Climate Change, in its most recent release, cautions that, in the absence of any major cut in emissions, projections of mortality and illness and other effects, like famine, worsen. (Lancet Commission, 2015)

11.2. If global temperature rise does not stay below 1.5°, Oakland may confront extreme, cumulative environmental exposures that challenge its capacity to avert adverse health and safety impacts (Rogelj et al., 2015). See further details below.

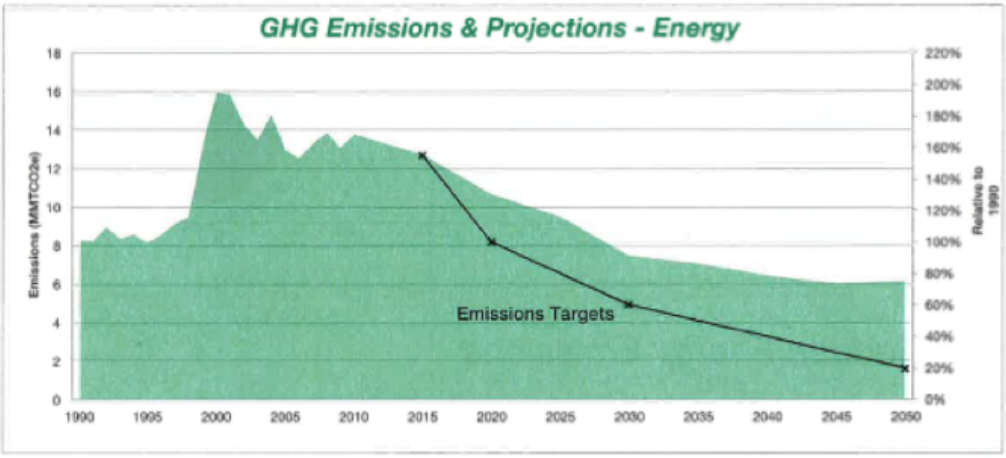
12. Alarmingly, the world, California, the Bay Area, and Oakland are not on track to meet the targets needed to slow and stop global warming.

12.1. An inventory of emissions in the global power sector finds that, despite international efforts to reduce CO_2 emissions, total remaining commitments in the global power sector "have not declined in a single year since 1950 and are in fact growing rapidly (by an average of 4% per year 2000–2012)." (Davis and Sokolow, 2014)

12.2. The 2015 report by the Lancet Commission on Health and Climate Change notes that global carbon emission rates have exceeded the worst-case scenarios used in 2009. (Lancet Commission, 2015)

12.3. By 2013, California still generated 459.3 MMT, while the state's population and economic output are expected to grow substantially by 2020. (CARB, 2015a.) This level of emissions exceeds California's 431 MMT target. (CARB, 2015b.)

Figure 3 Illustration of the gap between projected emissions decreases and reductions necessary to meet climate targets



The graph shows projected trends in Bay Area GHG emissions by sector through year 2050. The projected emissions take into account anticipated emission reductions from policies that have already been adopted at the State or regional level, as well as future policies that are likely to be adopted as an extension of current efforts. The chart also shows the emissions reduction trajectory needed in order to achieve interim (2020 and 2030) and long-range (2050) GHG reduction targets adopted by the State and the Air District.

12.4. Unofficial findings from the Bay Area Air Quality Management District's forthcoming Clean Air Plan / Climate Strategies Report (to be released July or August, 2016)

indicate that the Bay Area will similarly fall short. The report's projections indicate that the GHG reduction trajectory of each sector in the Bay Area will not meet the intermediate (2020, 2030) and long-term (2050) GHG reduction targets adopted by the State and the Air District. This failure may be even greater than reported, as the projected reductions already consider not only estimated effects of current State and regional policies but also future policies *that have not yet been adopted*. (See Figure 3 for example)

13. A different approach is imperative if health is to be protected from climate change. In this instance, a decision to prohibit coal's transport and processing through Oakland is an effective, reasonable and necessary means for contributing to the prevention of climate change-related health and safety impacts in Oakland.

13.1. Other than prohibition of this coal's transport through and storage and handling in Oakland, the submitted evidence and other existing literature does not present a mitigation or adaptation strategy that would effectively prevent the climate-related exposures and health consequences attributable to combustion of this coal.

13.2. In response to the City's question 7, CCIG/OBOT/TLS submitted to the record that, should the coal be prohibited from exporting through OBOT, "the product will continue to be shipped as it is today, through Stockton, CA; Levin Terminal in Richmond, CA; Pier G in Long Beach, CA; and may be shipped through the Ridley Terminal in Canada or the proposed Guaymas Terminal in Mexico in order to supply the market demands." (Tagami and Bridges, 2015).

13.3. However, review of the submitted record and additional investigation finds that the above assertion is not substantiated. Instead, as detailed in Table 2, prohibition of coal transport, storage and processing for shipment in Oakland is likely to stop this coal from being combusted altogether. In which case, this prohibition is health protective and not doing so could present a danger to public health and safety.

Table 2 Summary of information indicating coal would not be shipped if prohibited in Oakland

Oakland is the most viable option	
Project Spokesmen	The project's own spokespeople make the case that Oakland is by far the most feasible option: At a Utah Community Impact Board hearing, one of the representatives for the developer (strategic infrastructure advisor for the project Jeff Holt, or Master developer for the Oakland Army Base Mark McClure) stated: "There just aren't very many deep-water bulk terminals on the West Coast. Most of them are covered with containers. So the Oakland facility is a rare and serendipitous find/opportunity." (Utah Community Impact Board (CIB), 2015)
Report on Bowie Resources	"Records also show that Bowie Resources' plan to mine coal from Sufco appears to depend on the Oakland deal going through and that the company might not otherwise find a market for the fossil fuel. As such, shipping coal through Oakland likely will lead to a massive expansion of coal mining in Utah that might not otherwise occur." (Bondgraham, 2015)
Other Ports are not options	
Stockton	Stockton does not have the water depth to handle the ship size necessary for the large and heavy coal cargo, and requires an extra-expensive 3 days of travel to and from the sea. The Port of Stockton's website confirms that its high-tide depth is 40 feet; whereas the ships anticipated for this coal require 52 ft.[19]
Richmond / Levin	Levin Terminal currently does not have the capacity for the anticipated volume of coal, is already facing community opposition to the impacts of the relatively smaller amount of coal it does ship, and may not renew the contract to ship coal at all at its upcoming contract renewal.
Long Beach	Pier G of Long Beach is unlikely to have capacity for this added coal volume, since recently the Long Beach council voted against a new EIR as part of lease renewal on the basis that there would be no change of use or capacity of the storage "shed." Says Art Wong, Port spokesperson, "The environmental part is whether this (lease renewal) is going to increase the usage or change the capacity, and on that narrow environment issue, that's a no — there will be no increase in capacity." (Siegal, 2014).
Los Angeles	The Port of Los Angeles' contentious closure and expensive public cleanup of its coal terminal precludes it as an option (McGreevy, 2003)
Ridley and Gayama	Both the Ridley and Guayamas Terminals represent longer hauls (of roughly 1,500 and 1,00 miles, respectively, compared to a haul to Oakland of roughly 700 miles). Longer hauls, especially of a low bulk-to-value commodity such as coal raises questions of financial viability, especially because alternatives to coal power, including renewable energy, energy conservation and energy efficiency are increasingly available and cost competitive with coal (COP21, 2015). An investor report for Cloud Peak confirms that long hauls are cost prohibitive. In its 2011 investor report it states, "As previously disclosed, exports through the Ridley terminal incur significantly higher rail costs than through Westshore due to the longer multi railroad haul."[20]
Coal terminals are not opening	
Shortage of options	A 2011 investor report for Cloud Peak reveals an industry-wide challenge to find shipping locations, stating there were not enough terminals: "…. next year's exports will again be limited by available terminal capacity…."Error! Bookmark not defined.
No coal from Public Ports	The public ports of Portland, Seattle, Kalama, Tacoma, and Port of Oakland all declined various coal terminal proposals.[21]
Options in Washington fold	The Gateway Terminal at Cherry Point in Washington State was denied a permit to ship coal (Washington State Department of Ecology). Coal shipping through the Millennium Bulk Terminal is currently the subject of contentious debate (Quintana, 2016)
Oregon	Plans were dropped for coal export terminals at 1) Port Westward (Wilson and Swan, 2013); 2) Morrow Pacific and Coo's Bay due to local and state government resistance (Bernard, 2016; Elber, 2013).
Economic theory does not support coal shipment from elsewhere	
Dr. Thomas Power, professor of economics at The University of Montana and chairman of the economics department for thirty years, refuted coal industry arguments that "… decrease of exported coal would not change the amount of coal burned: only the source would change." He explains that, because of the effect of increased supply on prices and of prices on investment decisions, these theories are "incorrect, and inconsistent with both the basic principles of economics as well as the abundant literature regarding energy use and consumption patterns in Asia." (Power, 2011)	

[19] http://www.portofstockton.com/deepwater-channel-info
[20] http://www.sightline.org/2011/11/09/coal-company-destroys-key-argument-for-coal-terminal/
[21] http://www.sourcewatch.org/index.php/Millennium_Bulk_Terminals

14. **Preventing the transport and processing of coal for shipment in Oakland is the most reliable approach to preventing climate change health impacts attributable to this coal.**

15. **Given the likelihood this proposed coal would <u>not</u> be combusted if snot shipped from Oakland, Oakland has a causal link and accountability to the carbon commitments of this coal.**

Climate Change Exposure Assessment: Environmental Impacts

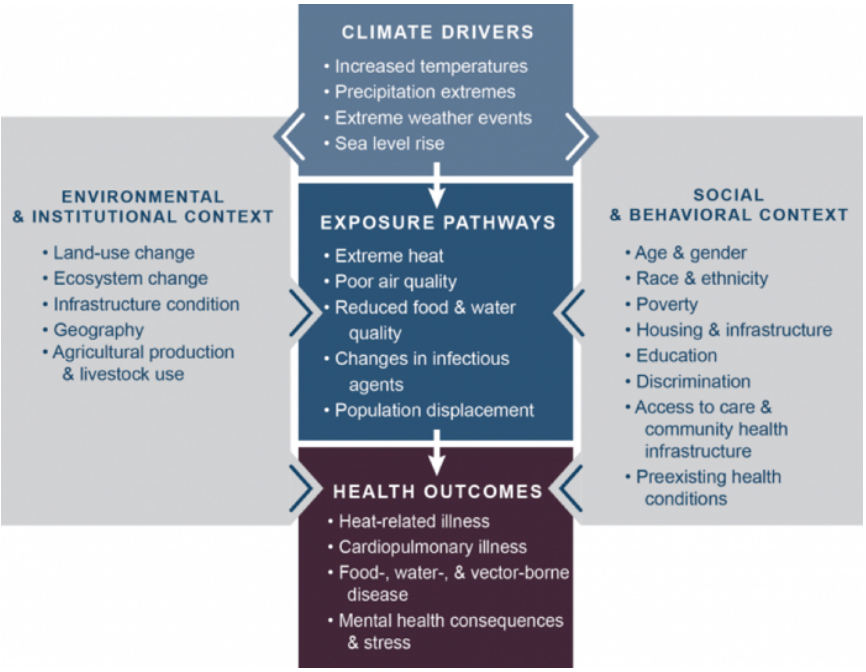
Climate change is the greatest health challenge of the 21st century, according to multiple recent reports and statements by many of the world's leading health experts. The impacts of climate change on health derive from the impacts of climate change on local and global environments. The magnitude of climate change and its health consequences depends on cumulative emissions of greenhouse gases into the earth's atmosphere, regardless of where those gases are emitted. The greater the cumulative emissions of GHG, the more severe the impact on human health, and the higher the risk of catastrophic climate changes that threaten human survival. Thus, the best way to prevent the health impacts of climate change — locally and globally — is to reduce the emissions of greenhouse gas emissions.

16. **Health impacts of climate result from exposure to changes in environmental conditions.**

    16.1. According to the U.S. Global Change Research Program (2016), climate change — including increased temperature, rising sea levels, ocean acidification, and extreme weather — leads to environmental exposures that create adverse health outcomes (See Figure 4). Climate-related health impacts are direct (e.g., exposure to heat), or indirect (e.g. water and food insecurity related to declining snow pack or reduced crop yields, or disease due to increases in air pollution) (Watts et al., 2015).

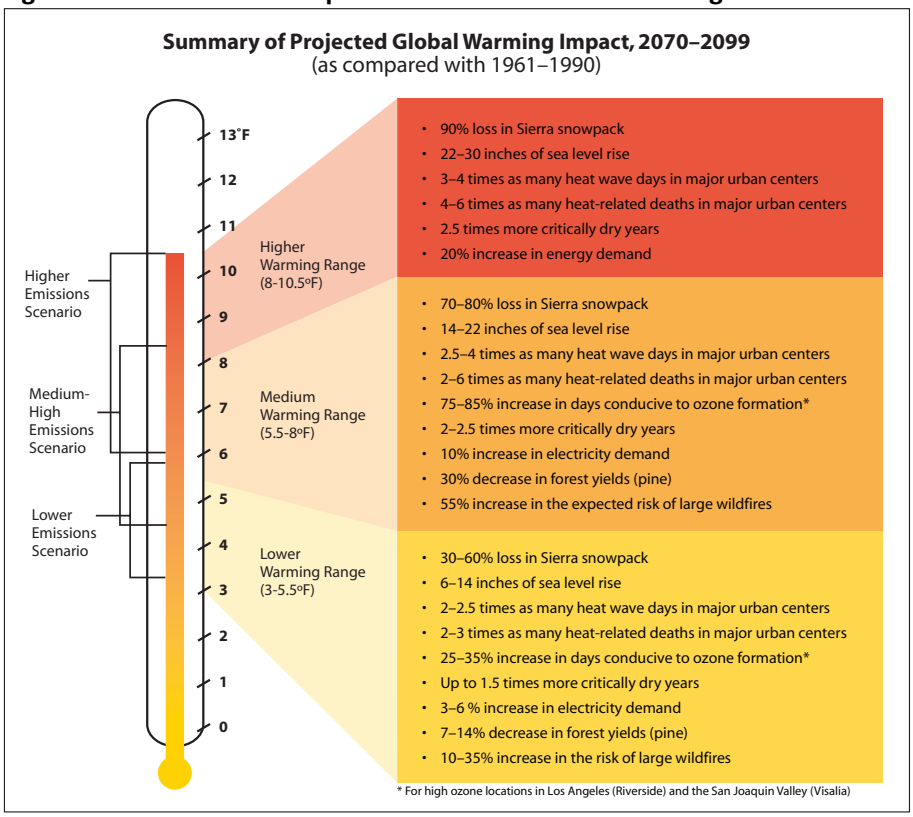
17. **Many impacts of climate change felt in Oakland will mirror or interact with those experienced in the Bay Area and the state. Figure 5 shows 2012 projections for climate impacts in California, and Table 2 presents climate change exposures germane to Oakland, as detailed in the following text.**

Figure 4 Framework for climate impact on health



Source: USGCRP. 2016. The Impacts of Climate Change on Human Health in the United States: a Scientific Assessment.

Figure 5 Environmental exposures related to climate change in California

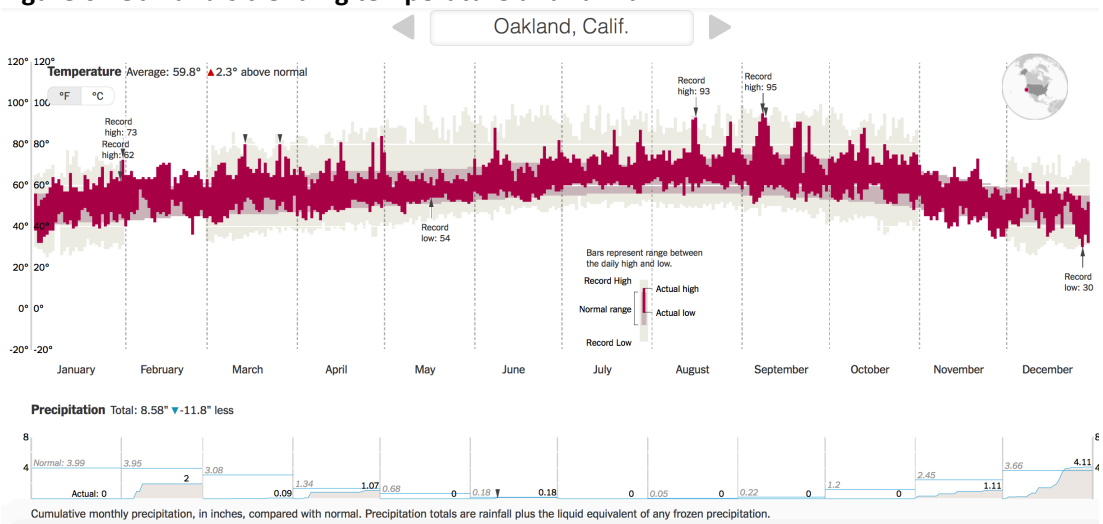


Source: California Climate Change Center report: Our Changing Climate. 2012.

18. Average temperature in Oakland, the number of extreme heat days, and the frequency and duration of heat waves will rise:

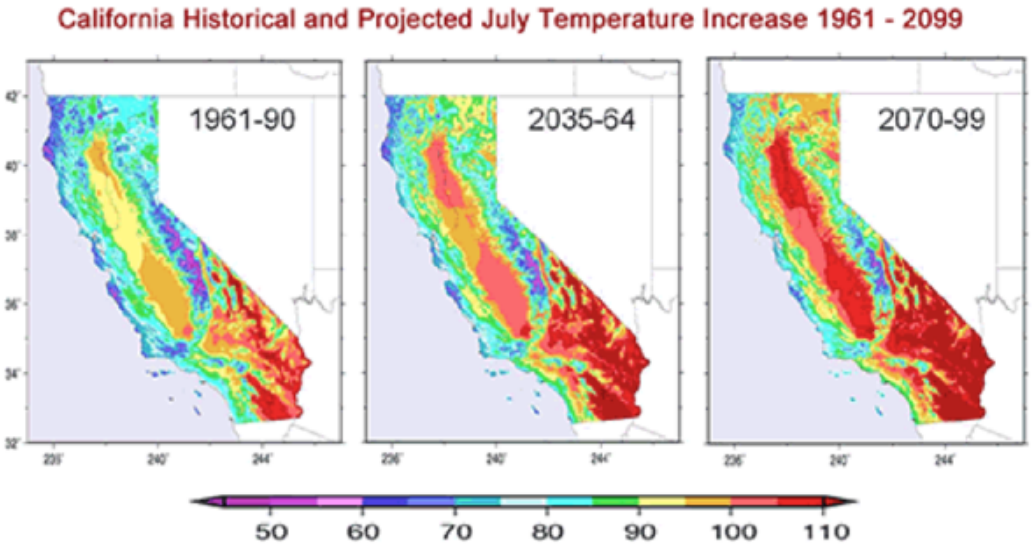
18.1. Oakland's average temperature in 2015 was 2.3°F above normal (59.8°F) – see Figure 6. (Lai, 2016) The average temperature in Alameda County is projected to increase by 3.3 – 5.6°F by 2065, (City of Oakland, 2016a; California Energy Commission 2010, 2012) along with annual average temperature rises throughout the state (Figure 7). (California Department of Public Health, 2014)

Figure 6 Oakland's trending temperature and rainfall



Source, New York Times, Science, February 19, 2016
Temperature and precipitation data are provided by AccuWeather.
The normal range of temperature is calculated by normalizing the weather from 1981 to 2010.

Figure 7 Historical and projected temperature changes in California as a result of climate change



Source: California Natural Resources Agency, 2009 California Climate Adaptation Strategy. Available at http://resources.ca.gov/docs/climate/Statewide_Adaptation_Strategy.pdf (accessed June 11, 2016).

18.2. By 2100, in the Bay Area between six and 10 more heat waves can be expected per year. (California Department of Public Health, 2014) Heat waves statewide will increase 2-4 fold, resulting in a 2-6 fold increase in heat-related deaths (California Climate Change Center, 2012)

18.3. The area will see an increase in extreme heat days, with a predicted 28 extreme heat days in 2017, compared with a current statewide baseline of 4 days. (City of Oakland, 2016a).

19. Warm temperatures will lead to increased ozone pollution in Oakland

19.1. Warmer temperatures from climate change will increase ozone production in Oakland and the frequency of days with unhealthy levels of ground-level ozone, a harmful air pollutant, and a component in the formation of smog. (EPA, 2016a; USGCRP, 2016)

19.2. The American Lung Association ranked Oakland 16th for high ozone days out of 228 metropolitan areas in the country (ALA, 2016 as of December 2015). Alameda County does not currently meet state air quality standards for ozone, with subsequent increases in harmful effects (BAAQMD, 2016). According to BAAQMD, rising temperatures threaten to undermine years of progress in improving air quality in the San Francisco Bay Area. The Bay Area Air Quality Monitoring District (BAAQMD) modeled that an anticipated 2° C (~4°F) increase in average temperatures would set back progress in reducing ozone by a decade. (BAAQMD, 2010).

19.3. A UC Berkeley study found that Bay Area ozone levels may be the most augmented by higher temperatures; parts of the Bay Area could experience an increase in ozone concentrations of nearly 10%. (Steiner et al., 2006; BAAQMD 2010).

20. Wildfires will increase air pollution in Oakland

20.1. Large wildfires in California and the West markedly increased in the mid-1980s, likely from increased spring and summer temperatures, earlier spring snowmelt, and drying trees. (Westerling, 2006; BAAQMD, 2010; EBMUD, 2014)

20.2. The risk of large wildfires in California could increase by as much as 55 percent in the next several decades. (CCCC, 2012) By 2085, increases in the number of large fires statewide would increase 58 percent to 128 percent above historical levels and the burned area will increase 57 to 169 percent. (EBMUD, 2014)

20.3. Wildfires generate huge quantities of particulate matter and release large amounts of CO_2 back into the atmosphere, thus contributing directly to the increase of GHG emissions in the atmosphere. (BAAQMD, 2010)

20.4. Some wild fires will impair Oakland's air quality as smoke plumes carry PM2.5 long distances. California's wildfires of June 2008 caused unprecedented concentrations of ozone and PM2.5, with 5 or 10-fold increases compared to normal. (BAAQMD, 2010)

Table 3 Climate change exposure summary

CO_2 emissions last for thousands of years and have global repercussions including rising temperatures, extreme heat, worsening air pollution, rising seas and extreme weather.	(Archer, 2009; Davis and Socolow, 2014; EPA, 2016a; EPA, 2016b; IPCC, 2013b)
Rising temperatures and extreme heat • OBOT coal will increase the probability of Earth exceeding a 1.5°C global temperature rise, largely considered the upper limit of tolerable anthropogenic warming. Oakland's average temperature in 2015 was 2.3°F above normal and Alameda County is projected to see a 3.3-5.6°F increase in temperature by 2065. • Frequency of extreme heat days and heat waves will increase greatly. Oakland is projected to have roughly 28 extreme heat days in 2017 (relative to 4 in 2016), and by 2100, the Bay Area may have 6 – 10 more heat waves per year over current conditions. • Rising temperatures can increase exposure to new pathogens.	(California Department of Public Health, 2014; California Energy Commission 2010, 2012; Lai, 2016; CCCC, 2012; City of Oakland, 2016a; IPCC, 2013b)
Worsening air pollution • Increased heat will increase production of and exposure to ozone, a dangerous air pollutant. Ozone levels in California could increase by as much as 10% due to increased temperatures alone, negating air quality progress that the state has made over the past decade. The American Lung Association ranked Oakland 16th for high ozone days out of 228 metropolitan areas in the country in 2015. • Wildfires already occur more often in California, and with continued rising temperatures will increase by 55% or more over the next few decades; by 2085 the State's burned area could increase 57% – 169%. Wildfires are a high priority in Oakland's hazard mitigation plan. Even if they occur elsewhere, winds can carry hazardous fire pollutants to Oakland, causing steep increases in exposure; California wildfires in June 2008 caused unprecedented concentrations of ozone and PM2.5, with 5 and 10-fold increases compared to normal.	(BAAQMD, 2010; CCCC, 2012; EBMUD, 2014; Jacobsen, 2008; Steiner et al., 2006; Westerling, 2006)
Rising sea levels and extreme weather events • Flooding will be more frequent and more intense due to rising sea levels, storm surges, and extreme precipitation events. California's sea levels are expected to rise 5-24 inches by 2050 and up to 66 inches by 2100, where a one-foot rise increases the probability of extreme storm surge floods by roughly a factor of ten, with Alameda County experiencing a 44% increase in land vulnerable to this event. Amplified climate feedback may actually raise sea level for California over 6 feet, inundating most of the flatlands. Flooding, storm runoff, and overwhelmed infrastructure can contaminate water with sewage or toxic chemicals. Housing, 2 (25%) fire stations, 5 health care facilities, 2 homeless shelters, 1 food bank, 6 childcare centers and 3 schools are at great risk. Exposure to waterborne pathogens will increase. • While extreme precipitation events will increase, overall, critically dry years will increase 1.5-2.5 fold in California. For the Bay Area, mean annual rainfall will decrease 4-5 inches. In 2015, Oakland's total precipitation was 11.8" less than average. The current drought is 15 – 20% worse due to climate change, and the odds of future severe droughts have roughly doubled over the century. With a 7.2°F (4°C) rise in temperature, Oakland's (Mokelumne) watershed spring snowpack could decrease by up to half; drought and heat may render the watershed inadequate to support Oakland's needs. EBMUD anticipates severe water shortages and rationing, decreased water quality, and impaired flood control and electricity infrastructure. • Droughts, heat, and overdrawn groundwater threaten California agriculture. 2015's drought led to a 72% increase in groundwater extraction, 45% increase in fallow land, 21,000 lost jobs, and $2.6 billion in losses. Increased heat will worsen quantity and quality of crop yield and raise food prices, reducing the availability of affordable produce, especially for the poor.	(CCCC, 2012; Committee on Sea Level Rise in California, Oregon and Washington, 2012; CDPH, 2014; EPA, 2016a; USGCRP, 2016; Lai, 2016; Williams, 2015; Hansen 2016; NASA images; Berdalet, 2015; Semenza, 2012; EBMUD, 2014; Howitt, 2015; CCC, 2012)

21. For a significant portion of Oakland, risk of exposure to flooding will increase, due to sea level rise, storm surges, and high precipitation storms

21.1. California is projected to experience, relative to 2000, a likely sea level rise of 2–12 inches by 2030, 5–24 inches by 2050, and 17–66 inches by 2100. (Committee on Sea Level Rise in California, Oregon and Washington, 2012). New research suggests the higher end of that range is more likely, with leading climate scientist James Hansen and his colleagues reporting that amplified climate feedbacks may create several meters (over 6 feet) of sea level rise by 2100. (Hansen, 2016.) Maps prepared by the National Oceanic and Atmospheric Administration show that 6 feet of sea rise will inundate a large part of West Oakland, including the site of the OBOT near the Bay Bridge toll plaza. (See Figure 8)

Figure 8 Inundation of Oakland neighborhoods with 6-ft sea level rise Oakland - without prevention

Source: United States Department of Commerce, National Oceanic and Atmospheric Administration, National Ocean Service, https://coast.noaa.gov/slr/

21.2. As the average sea level rises, the number and duration of extreme storm surges and high waves are expected to escalate, and this increases the risk of flooding, coastal erosion, and wetland loss. (Committee on Sea Level Rise in California, Oregon and Washington, 2012; City of Oakland, 2016a)

21.3. Extreme storms with extreme precipitation are likely to occur more frequently. (EPA, 2016a; USGCRP, 2016) A 1 foot rise in sea level changes a “1 in 100” storm surge flood event into a “1 in 10” storm surge flood event. (CCCC, 2012) Extreme weather events and storm surges can damage or exceed the water infrastructure (such as

drinking water or wastewater treatment plants). Extreme rainfall increases flooding, storm runoff, and overwhelmed infrastructure which can contaminate water with sewage or toxic chemicals. (EPA, 2016a)

21.4. The number of acres vulnerable to flooding is expected to increase 20 to 30 percent in most parts of the Bay Area, with some areas projected for increases over 40 percent. Coastal areas are estimated to experience an increase of approximately 15 percent in the acreage vulnerable to flooding. Alameda County is expected to experience a 44% increase in area of land vulnerable to a 100-year flood event. (CDPH, 2014)

21.4.1. A large portion of Oakland's infrastructure and most vulnerable housing are close to sea level. Oakland's infrastructure may be overwhelmed since much of it is located in flood zones (airport, wastewater, roads, rail, power, telecommunications utilities) (See Table 3). (City of Oakland, 2016a; Pacific Institute, 2014; Cal-Adapt; San Francisco Bay Conservation and Development Commission, 2011)

21.4.2. During the winters of 1982–1983 and 1997–1998, abnormally high seas and storm surges caused millions of dollars' worth of damage in the San Francisco Bay area. "Highways were flooded as six-foot waves crashed over waterfront bulkheads, and valuable coastal real estate was destroyed." (CCCC, 2012)

21.5. The areas of Oakland experiencing the greatest social vulnerability, such as West Oakland, are also areas that will be highly impacted by excess water, be it sea level rise, storm surges, or flooding.

21.5.1. At-risk infrastructure in Oakland includes 2 (25%) fire stations, 5 health care facilities, 2 homeless shelters, 1 food bank, 6 childcare centers and 3 schools. (City of Oakland, 2016b) Flooding of this infrastructure would be highly disruptive (Table 4).

21.5.2. Flooding of homes could lead to displacement and homelessness.

Table 4 Critical infrastructure needed for health and safety or serving vulnerable populations that will be impacted by sea-level rise without climate change prevention

City Facilities	Total Number	Number at Risk from Sea Level Rise	
		16 inches by 2050	55 inches by 2100
Emergency Response Facilities			
Fire Stations	8	2	2
Facilities serving at-risk populations			
Health Care facilities	87	5	13
Homeless shelters	12	2	4
Food Banks	14	1	5
Facilities serving vulnerable, less mobile populations			
Senior housing facility	45	0	3
Childcare center	146	6	16
Schools	81	3	13

Source: City of Oakland Preliminary Resilience Assessment, 2016b

22. Exposure to water-borne pathogens and contaminants will increase.

22.1. Increasing temperature, more frequent heavy rains and runoff, and the effects of storms, can increase exposure to waterborne pathogens (bacteria, viruses, and parasites); toxins produced by harmful algal and cyanobacterial blooms in the water; and chemicals. (USGCRP, 2016; EPA, 2016a) Increased microbial contamination and harmful algal blooms increase the risk of water-borne illnesses, reduce access to recreational waters, and preclude the harvesting of shellfish and other marine food sources. (Berdalet, 2015; Semenza, 2012)

23. Oakland's water supply will be imperiled, with possibly severe water shortage:

23.1. The Bay Area is projected to experience a moderate decline in annual rainfall, 1 to 3 inches by 2050 and 4 to 5 inches by 2090 is projected throughout the region (CDPH, 2014). The number of critically dry years in California projected for a 1.5-2.5 fold increase (CCCC, 2012)

23.2. California suffers from periodic droughts, and the odds of a severe drought in California have roughly doubled over the past century. The severity of California's current drought has intensified 15 - 20 percent due to climate change. (Williams, 2015) During years of extreme drought, Oakland can expect severe water shortages and rationing. (Department of Water Resources, 1979; EBMUD, 2014)

23.3. California is reliant on runoff from spring snow-melt. Over the century, the Sierra Nevada spring snowpack is projected to reduce by as much as 30 to 90 percent. (CCCC, 2012)

23.4. The Mokelumne River watershed, which supplies 90% of Oakland's water, is relatively small, and 40% is developed or unprotected, making it more vulnerable to degradation (See Figures 9 and 10). (The Nature Conservancy of California, 2012)

23.4.1. With growing population, drought and more heat may render the watershed inadequate to support Oakland's needs. In 2015, Oakland's total precipitation was 11.8" less than average (Lai, 2016). Under a scenario of a 7.2^{o}F (4°C) rise in temperature, the Mokelumne watershed spring snowpack could decrease by up to half. (East Bay Municipal Utilities District, 2014)

23.5. The states emerging groundwater crisis, if not resolved, will threaten some watersheds and increase pressure on others. (The Nature Conservancy of California, 2012)

23.6. The East Bay Regional Municipal Utilities District, (EBMUD), which supplies Oakland's water, forecasts that with increases in water demand and climate change, there will be increases in severe water shortages, leading to increased severity of water rationing, decreased water quality, and the district will face challenges managing infrastructure that controls flooding and electricity. (EBMUD, 2014)

24. Climate impacts will impair agricultural production in California, in particular In the Central Valley.

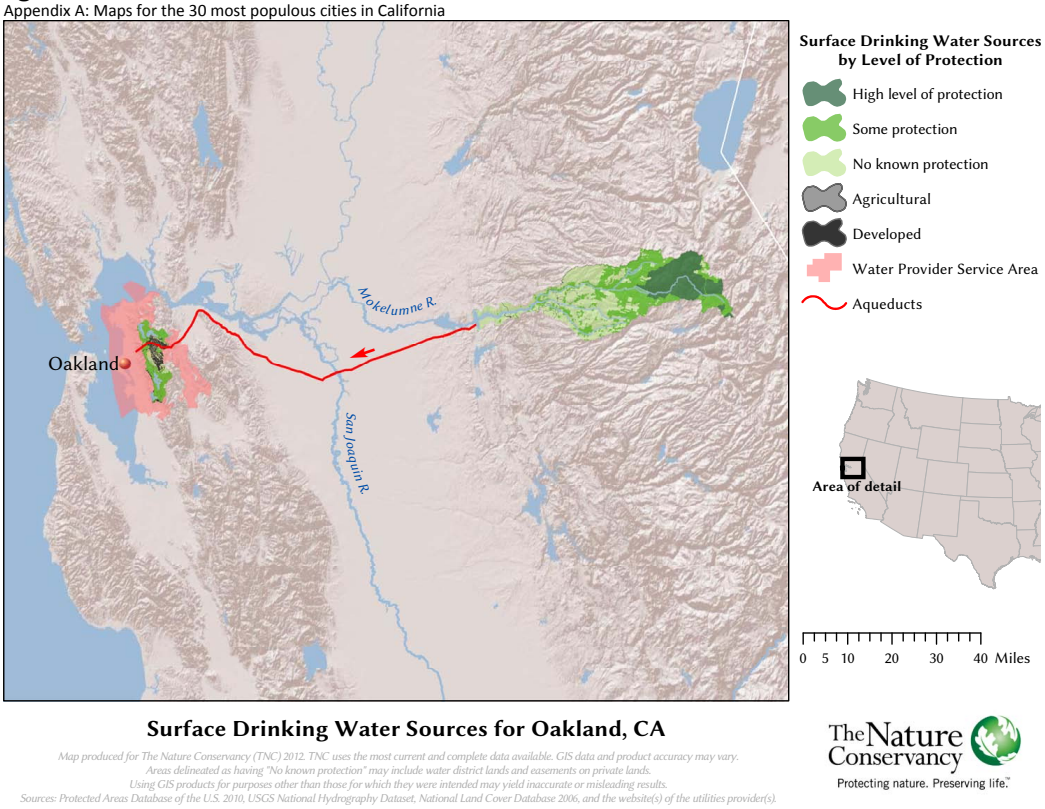
24.1. The current drought is responsible for the greatest surface water shortfall ever experienced by California agriculture. (Howitt, 2015)

24.2. California farmers could lose as much as 25 percent of the water they currently need. During this drought, groundwater extraction increased 72 percent, there was a 45 percent increase in land left fallow, and 21,000 jobs were lost, with a total economic impact of $2.7 billion. (Howitt, 2015) These consequences impact the general wealth of the state and increase food insecurity, especially for the poor.

24.3. Increased temperatures are likely to worsen the quantity and quality of crop yield. Climate-related rises in temperature and ozone pollution will make plants and trees more susceptible to disease and pests and interfere with plant growth. Reduced crop yields are associated with higher food prices, and could reduce the availability of affordable fresh produce. (CCCC, 2012).

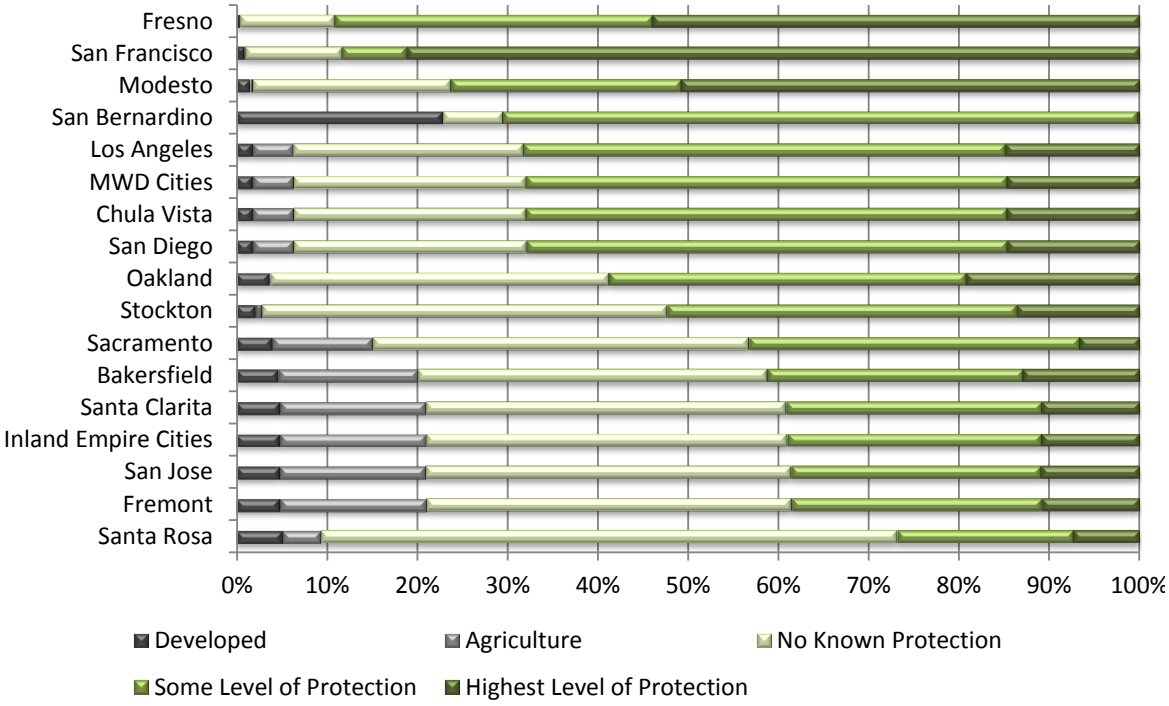
Figure 9 Oakland's watershed

Appendix A: Maps for the 30 most populous cities in California



Source The Nature Conservancy

Figure 10 Land Use and Protection of Watersheds Supplying Drinking Water by City



Source: The Nature Conservancy

Impacts of Climate Change on Health, focus on Oakland

The health impacts of climate change are occurring now and will worsen in coming years as the cumulative effects of climate change mount. Recent surveys of physicians across the U.S. show that a majority are seeing the effects of climate change in their patients now (Sarfaty et al. 2014). Table 5 details climate-related health impacts relevant to Oakland.

25. Heat illness and deaths may increase in Oakland.

25.1. Extreme heat increases the risks of heat stroke/exhaustion, heart attack, stroke, respiratory disease, and death from dehydration (US EPA, 2016a). Heat waves are more likely to cause excess deaths when the temperature rises above that to which the local population is accustomed and acclimated, especially in the absence of effective heat death prevention plans.

25.2. In the Bay Area, Oakland is considered the area most vulnerable to extreme heat, according to a 2012 risk assessment. (California Energy Commission's California Climate Change Center, 2012) This heightened vulnerability is due in part to Oakland residents being less accustomed to high temperatures and to greater socio-economic vulnerability and fewer resources to respond to heat.

25.3. Extreme heat events result in more fatalities than any other weather-related phenomenon (Centers for Disease Control and Prevention 2012). By mid-century, mortality caused by heat may increase 2-3 fold in California urban centers during an extreme heat event (CCCC, 2012; Basu and Ostro, 2008a, 2008b). Annual premature mortality due to extreme heat in California is projected to range from 2,100 to 4,300 in 2025 and from 6,700 to 11,300 for 2050. (Ostro 2009, 2011; BAAQMD, 2010).

25.3.1. In the California heat wave of 2006, there were an estimated 655 excess deaths (an average 6% increase), 16,166 excess ED visits, and 1,182 excess hospitalizations statewide. (Knowlton, 2009)

25.3.2. Mortality in Alameda County may increase 9.8% for every 10° F change in mean daily temperature, with an excess mortality risk of 5.1% for people > 65. (Ostro, 2011)

25.3.3. Respiratory and cardiovascular hospital admissions in Alameda County may increase 2.6% and 1.4% per 10°F increase in mean daily temperature. (Ostro,2011)

Table 5 Climate change impact summary

Health effects of heat exposure	
• Extreme heat events – especially those above temperatures a population is accustomed to – result in more fatalities than any other weather-related phenomenon, due to heat stroke/exhaustion, heart attack, stroke, respiratory disease, and dehydration. Oakland is considered the most vulnerable to heat in the Bay Area. • By 2050, mortality caused by an extreme heat event may increase 2-3 fold in California urban centers (CCCC, 2012; Basu and Ostro, 2008a, 2008b). Annual premature mortality due to extreme heat in California is projected to range from 2,100 - 4,300 in 2025 and from 6,700 - 11,300 in 2050. Mortality in Alameda County may increase 9.8% for every 10°F change in mean daily temperature, with an excess mortality risk of 5.1% for people > 65. Respiratory and cardiovascular hospital admissions in Alameda County may increase 2.6% and 1.4% per 10°F increase in mean daily temperature.	(CDC, 2012; Basu and Ostro, 2008a, 2008b; California Energy Commission, 2012; CCCC, 2012; CDC 2012; Ostro, 2009, 2011; Reeves et al., 1994; USGCRP, 2016; US EPA, 2016a)
Impacts from rising sea levels and extreme weather	
• 3,100-5,200 Oakland residents are at risk of flooding in coming decades due to higher storm surges, extreme precipitation events, and sea-level rise. Resulting effects include traumatic injury and death, mental health disturbances (anxiety, stress-related trauma), increased infection, communicable disease and other illness per contact with contaminated and toxic run-off, displacement, and disrupted access to safe food, water and essential services. • Consequences of climate effects on water quantity and distribution due to extreme precipitation, flooding and droughts may include increases in vector and water-borne disease incidence and prevalence. Drought, snow melt, and ground water depletion independently and together can affect the availability of clean and safe water for drinking and basic hygiene, increasing risk of infection and spread of disease. • The agricultural effects of drought will lead to higher food prices and food insecurity, along with the diet-related conditions that follow (hypertension, diabetes, etc.). Drought furthermore increases the likelihood of communicable illness spread.	(Cal-Adapt; CCCC, 2012; CDC, 2010; City of Oakland, 2016b; City of Oakland, 2016a; Howitt, 2015; Pacific Institute 2014; San Francisco Bay Conservation and Development Commission, 2011; USGCRP, 2016; EPA, 2016a)
Health outcomes of temperature interaction with ozone and particulate matter pollution	
• Temperature rises accelerate ozone production more in already polluted areas, and air pollution has more severe effects on those with underlying illness. West and East Oakland's high existing air pollution and prevalence of chronic disease makes them especially vulnerable to climate-related increased air pollution. Increased ozone exposure due to rising temperatures will increase the 8,800 deaths that already occur each year in California due to ozone and particulate matter exposure. Ozone pollution also induces respiratory irritation, impaired lung function, aggravation of asthma, allergies, and other lung diseases, heart attacks, and stroke. • Rising temperatures due to greenhouse gases can independently cause excess mortality from ozone and particulate matter exposure: Excess annual air pollution deaths due solely to GHG-related temperature rise may reach roughly 400 ozone-attributable and 600 PM2.5-attributable deaths in the U.S. per 1°C increase. • Temperature rise increases wildfires and resulting air pollution, especially PM2.5, leads to respiratory illness, cardiovascular illness, and premature mortality.	(CCCC, 2012; EPA, 2013; EPA, 2016a; Jacobsen, 2008)

26. Ozone-related mortality and morbidity will increase

26.1. The health impacts of ozone include respiratory irritation, impaired lung function, increased susceptibility to respiratory infections, aggravation of asthma, allergies, and other lung diseases, cardiovascular disease including heart attacks and stroke, and premature death. (EPA, 2013)

26.2. Rising temperatures due to climate change can cause excess mortality associated with interactions between ozone and particulate matter exposure. Excess annual air pollution deaths due solely to GHG-related temperature rise may reach roughly 600 PM2.5-attributable and 400 ozone-attributable deaths in the U.S. per 1°C increase. (Jacobsen, 2008) In one study, it was projected that by the 2020s, climate change could cause a 7.3% increase in regional summer ozone-related asthma emergency department visits for children aged 0–17 years (across the New York metropolitan region). (Sheffield, 2011)

26.3. Those most vulnerable to ozone's effects are children and teens, elderly over 65; people who work or exercise outdoors; people with existing lung diseases, such as asthma and chronic obstructive pulmonary disease; and people with cardiovascular disease. However, even healthy individuals can experience chest pain, coughing, nausea, and pulmonary congestion when exposed to ground-level ozone. (ALA, 2016; EPA, 2014)

27. Oakland residents face an increasing risk to their health and safety from flooding linked to sea level rise, storm surges, and extreme precipitation.

27.1. An estimated 3,100-5,200 Oakland residents[22] are at risk of flooding in coming decades due to higher storm surges, extreme precipitation events, and sea-level rise. (Pacific Institute, 2014) Likely effects of these scenarios include traumatic injury and death, mental health disturbances (anxiety, stress-related trauma), increased infection and communicable disease, displacement, job loss, and disrupted access to safe food, water and essential services. (City of Oakland, 2016a; Pacific Institute, 2014)

27.2. The availability of safe food and drinking water may be limited, and hospitals, emergency services and communications infrastructure may be disabled or hampered. Disruption may be at a city-wide level. (City of Oakland 2016a)

27.3. Previous floods in Oakland have led to extensive exposure to water contaminated with toxic waste and / or pathogens. These exposures can increase risk for cancer or

[22] Oakland residents living in West Oakland, Chinatown, San Antonio, Fruitvale, Central East Oakland, and Elmhurst districts will experience the most exposure to flooding in the future. (Pacific Institute)

other diseases, or promote spread of infectious disease. In particular following power outages, there can be increases in stomach and intestinal illness. (EPA, 2016a)

27.4. Emergency evacuations pose health risks to older adults and others who may be unable to access evacuation routes or have difficulty in understanding or receiving warnings of impending danger. (EPA, 2016a)

28. Changes in water quantity and distribution through extreme precipitation and flooding (compounded by interaction with droughts) may increase water-borne disease incidence and prevalence.

28.1. People become ill if they come into contact with contaminated drinking or recreational water. Health impacts may include gastrointestinal illness like diarrhea, effects on the body's nervous and respiratory systems, or liver and kidney damage (USGCRP, 2016; EPA, 2016a)

28.2. Climate effects on the distribution and quality of surface water can impede personal hygiene and impair local sewage systems. (USGCRP, 2016; EPA, 2016a) Natural events (e.g., floods, storms, heavy rainfall, and snowmelt) often can wash fecal matter into potable water. (USGCRP, 2016; EPA, 2016a).

29. Health effects of drought, snow melt, and ground water depletion on Oakland

29.1. Drought, snow melt, and ground water depletion independently and together can affect the availability of clean and safe water for drinking and basic hygiene, increasing risk of infection and spread of disease. (CDC, 2010)

30. Rising CO_2 and climate change will affect the quality and distribution of food, with subsequent effects on food safety and nutrition. (USGCRP, 2016)

30.1. Drought and extreme weather events can reduce crop yield. Drought and heat also affect the health of livestock and levels of livestock milk production. Related increases in food prices lead to increases in food insecurity, which in turn is associated with increased risks of chronic diseases such as diabetes, obesity, and hypertension. Food insecurity disproportionately impacts poor people. (USGCRP, 2016; EPA, 2016a)

30.2. Higher air and water temperatures foster more rapid growth of microbial organisms such as Salmonella or Vibrio that cause food and water-borne illnesses. (Tirado, 2010; USEPA, 2016a) Higher sea surface temperatures will lead to higher mercury concentrations in seafood, and flooding can introduce contaminants into the food chain through stormwater runoff. (USEPA, 2016a)

30.3. Higher atmospheric concentrations of carbon dioxide are associated with lower levels of protein and essential minerals in crops such as wheat, rice, and potatoes. (USEPA, 2016a)

31. Wildfires and their associated air pollution can cause deaths, injuries, and eye, respiratory, and cardiovascular illnesses– in Oakland.

31.1. Community smoke exposure from wildfires – even when the fire occurs remotely – has been associated with increased emergency department visits and hospital admissions for chronic obstructive pulmonary disease (COPD), bronchitis, asthma, and chest pain. (Ginsberg, 2008) Through a meta-review, a study found very strong evidence linking fire smoke with increased risk of respiratory and cardiovascular diseases and found that children, the elderly and those with underlying chronic diseases appear to be highly susceptible. (Liu, 2015) Exposure to wildfire smoke can increase mortality: an Australian study found a 5% increase in non-accidental mortality and a 10% increase in cardiovascular mortality following exposure to wildfire (bushfire) smoke. (Johnston, 2008)

31.2. After the 2003 Californian wildfires, average increases of 70 microg/m(3) PM(2.5) were associated with 34% increases in asthma admissions. For every 10 microg/m(3) wildfire-related PM(2.5) exposure, there were increases in hospital admissions of: 9.% for acute bronchitis; 6.9% for chronic obstructive pulmonary disease (COPD) among 20-64 year olds; 6.4% for pneumonia in 5-18 year olds. There was a 6.1% increased rate of admission for cardiovascular complaints, including an 11.3% increased rate of admission due to cardiac failure. (Delfino, 2003) Effects can be immediate or present after several weeks. (Moore, 2006)

32. Climate change impacts mental health.

32.1. Experiencing an extreme weather event can cause acute stress, post-traumatic stress disorder, anxiety, depression, and other mental health consequences, particularly when a person loses livelihoods, loved ones, homes, and communities. Even the perceived threat of climate change (for example from reading or watching news reports about climate change) can influence stress responses and mental health. (USGCRP, 2016)

32.2. Some groups of people are at higher risk for mental health impacts, such as children and older adults, pregnant and post-partum women, people with pre-existing mental illness (see above), people with low incomes, and emergency workers. (USGCRP, 2016)

33. Global warming may affect seasonality (increase duration or altered timing) of certain allergic respiratory disorders, triggering asthma and hay fever (IPCC, 1997).

33.1. Allergic illnesses, (e.g., hay fever), affect about one-third of the U.S. population; more than 34 million Americans have been diagnosed with asthma (EPA, 2016a).

34. Changing climate conditions may lead to changes in the distribution of disease-carrying vectors such as ticks and mosquitos, with subsequent changes in the occurrence of vector-borne diseases such as dengue fever, west nile virus, or zika.

34.1. In California, the dengue and zika mosquito is now present in multiple counties.

35. Some populations in Oakland will be disproportionately vulnerable to these adverse health outcomes.

35.1. While the health impacts of climate change affect all Oakland residents, residents of West Oakland, especially in neighborhoods adjacent to the former Oakland Army Base, are at increased risk due to preexisting health conditions, higher exposure to environmental hazards (such as heat islands and housing in rising sea-level and flood zones), social, economic and demographic factors, and more limited adaptive capacity (California Energy Commission, 2012). West Oakland – and East Oakland – will disproportionately bear environmental exposures and morbidity/mortality burdens due to climate change.

35.2. ***Vulnerability to heat:*** Outdoor workers, homeless, the elderly, low-income people who lack access to air conditioning (or cannot afford to turn it on), young children, pregnant women, people with pre-existing chronic illness, and those who take certain medications are all more vulnerable to adverse health consequences of heat. (USGCRP, 2016)

35.2.1. Heat aggravates existing medical problems in vulnerable populations (Canadian Global Change Program, 1995). For example, mortality during oppressively hot weather is associated predominantly with preexisting cardiovascular, cerebrovascular, and respiratory disorders, as well as accidents. (Haines, 1993; IPCC 1997)

35.2.2. Lower income populations have less access to resources that can offset heat and its related illnesses, including the ability to afford air conditioning and associated electric costs. Modeling of heat-associated mortality finds a significant protective benefit to air conditioner ownership, where a 10% increase in air conditioning prevalence reduced the temperature mortality co-efficient by 1.4% (Ostro 2011). Additionally, lower income populations often lack the medical coverage needed to receive prompt treat ment for a heat-related medical condition. (Pacific Institute, 2012) West Oakland has some of the highest levels of poverty in the Bay Area.

35.2.3. People that live in urban heat islands - areas with dense building, high concentrations of impervious surfaces, low tree canopy, and little green space - are at particular risk of heat illness. (USEPA, 2016h) Oakland has several areas in the flatlands with these characteristics.

35.2.4. In temperate coastal regions such as Oakland, excessive heat is infrequent and populations accordingly are less acclimated and less likely to have air conditioning or be familiar with how to protect themselves during a heat wave. (WHO, 2003)

35.3. ***Vulnerability to poor air quality:*** People most at risk for adverse health consequences of increased ozone exposure include people with asthma and other respiratory diseases (e.g. COPD, emphysema), people with cardiovascular disease, children, older adults, and people who are active outdoors, especially outdoor workers. (EPA, 2013)

35.4. ***Vulnerability due to living in already polluted settings:*** Those living in neighborhoods with higher levels of air pollution - such as West Oakland - are more at risk, in part because of their higher prevalence of pollution-related chronic illness. (Jacobsen, 2008)

Description of submitted evidence

Five submissions were made to the city that provided documentation of the relationship between the export and combustion of coal, the association with climate change, and the impact on health and safety. The evidence provided in these submissions is included in our briefs, along with findings from supplemental review.

Substantiated points made	**EJ**	**SC**	**NCOI**	**Fox**	**UCS**
Coal export will lead to coal combustion and increased greenhouse gas emissions, with direct local and global climate change consequences	x	x		x	x
Coal export is inconsistent with state, regional, and local climate and air quality policies	x		x	x	x
Climate change and related health impacts in Oakland are and will be significant	x	x	x		x
Health impacts will relate to sea level rise, water shortages, temperature rise, air pollution, their interaction, and more		x	x		x
The cumulative greenhouse gas emissions of the project will be significant on a global scale		x	x		x
This issue is urgent and international commitment involves the whole world community – from global to local	x	x	x		x
Prohibiting transport, storage and handling of the Utah coal as proposed is an effective way to partially protect Oakland from climate change impacts		x			x
There is no established or meaningful mitigation of the climate impacts this coal will have (e.g., no clean coal, no supplanting dirtier fuel, etc.)	x				x

EJ = Irene Gutierrez, Earth Justice on behalf of Sierra Club, West Oakland Environmental Indicators Project, Communities for a Better Environment, San Francisco Baykeeper (Letter dated 9/2/15)

SC = Deborah Niemeier of Sustainable Systems Research, LLC for Sierra Club (Report submitted 9/21/15)

NCIO = No Coal In Oakland (Letter dated 9/18/15)

Fox = Phyllis Fox for Sierra Club (Report submitted 9/21/15)

UCS = Laura Wisland, Union of Concerned Scientists (Letter dated 9/18/15)

Chapter 9: Noise Effects of Coal Transport and Handling in Oakland

Key Points and Summary of Submitted Evidence

Two documents submitted to the Council for its 9/21/2015 hearing on the Army Base Gateway Redevelopment Project addressed noise levels that would be generated through the export of coal through Oakland:

- The Human Health Effects of Rail Transport of Coal Through Multnomah County, Oregon (Multnomah County Health Department 2013)
- Environmental, Health and Safety Impacts of the Proposed Oakland Bulk and Oversized Terminal by Phyllis Fox, PhD for Sierra Club (Fox 2015)

Conclusions were generally grounded in scientific literature, especially when documenting a range of health effects due to noise exposure.

The main points made in the submissions included:

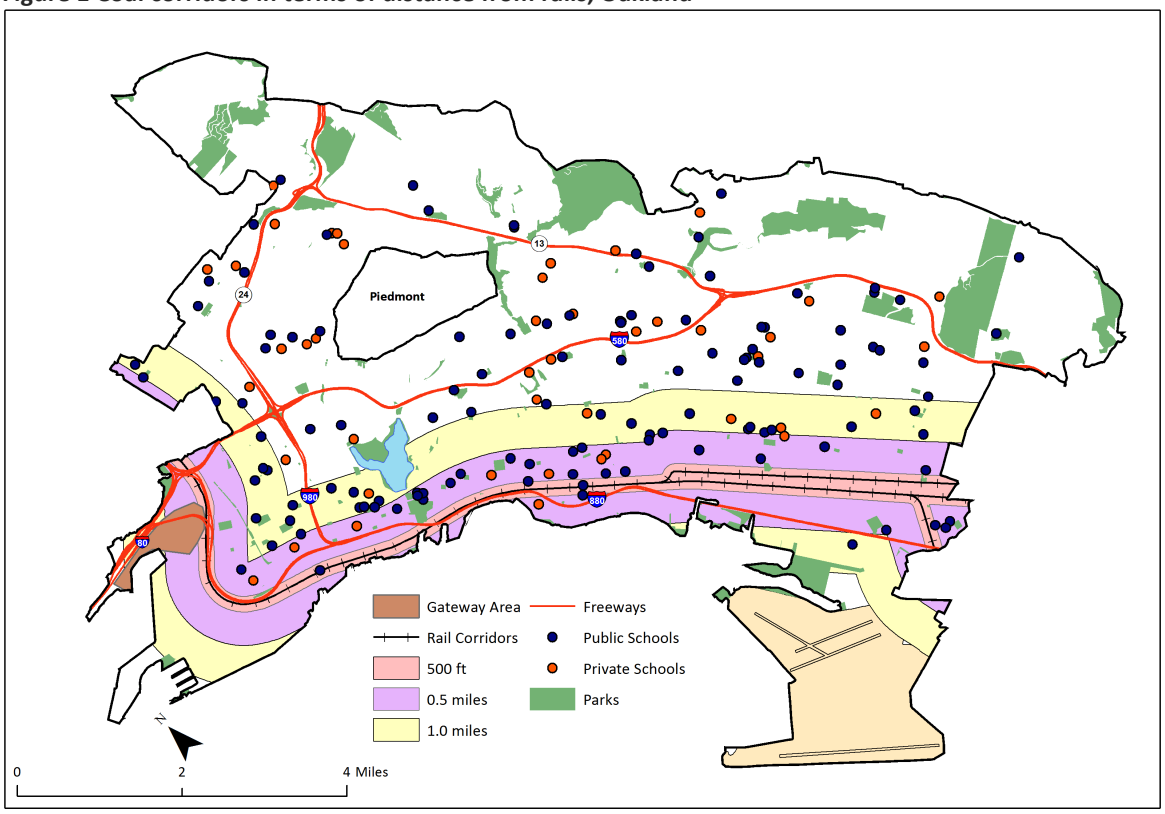
- Coal transport will likely generate pronounced noise
- Noise is implicated in a wide range of adverse health effects
- Cumulative health effects are likely

Additionally, from further analysis, we find that:

- Baseline noise exposure in much of West Oakland already exceeds levels considered compatible with residential usage, and current noise levels are already sufficient to interfere with activity and learning, as well as impair sleep.
- West Oakland will experience increased noise exposure pursuant to OBOT's addition of coal train activity.
- An increased proportion of people, in a larger geographic area, may experience higher risk for a greater number and / or severity of adverse health effects, including:
    - serious annoyance, sleep disturbance, speech disturbance, activity interference, myocardial infarction risk, learning and functioning disturbance (depending upon quality of indoor / classroom acoustics), and possibly hearing deficits
- Several sensitive areas are within the boundaries of anticipated exposure (Figure 1).
    - Raimondi Park is very close to the tracks and is heavily utilized, mostly by children. Roughly 27,375 people visit Raimondi per year, with 54,750 person hours of potential exposure each year.

Details and citations supporting these statements are included in the review below, combining both those that were submitted along with additional information and citations identified by the panel through supplemental review.

Figure 1 Coal corridors in terms of distance from rails, Oakland



Source: CAPE, with rail data from CalTrans, parks data from CPAD 2015b, Gateway area from Oakland Redevelopment Agency, schools from CDE.

Findings

1. **Noise is an environmental stressor that activates physiological responses which in turn can adversely impact health (Ising and Braun 2000). Noise can also directly impact hearing.**

2. **Characteristics of noise, the exposure setting, and the person experiencing the noise influence its impact.**

   2.1. Impact on health can vary (1) by *noise characteristics* including sound level, objective noise volume, intensity, duration, continuity, and contrast to ambient / background noise; (2) by *the exposure setting* including time of day that noise is experienced, the distance from source, and wind gradient; (3) by the *functional context*, such as if heard in a hospital or school; and (4) by *subjective perception* of the noise based upon an individual's characteristics. (Münzel et al. 2014) See Table 1 for definitions of acoustical terms.

Table 1: Definition of Acoustical Terms

Term	Definitions
Decibel, dB	A unit describing, the amplitude of sound, equal to 20 times the logarithm to the base 10 of the ratio of the pressure of the sound measured to the reference pressure. The reference pressure for air is 20.
Sound Pressure Level	Sound pressure is the sound force per unit area, usually expressed in micro Pascals (or 20 micro Newtons per square meter), where 1 Pascal is the pressure resulting from a force of 1 Newton exerted over an area of 1 square meter. The sound pressure level is expressed in decibels as 20 times the logarithm to the base 10 of the ratio between the pressures exerted by the sound to a reference sound pressure (e.g., 20 micro Pascals). Sound pressure level is the quantity that is directly measured by a sound level meter.
Frequency, Hz	The number of complete pressure fluctuations per second above and below atmospheric pressure. Normal human hearing is between 20 Hz and 20,000 Hz. Infrasonic sound are below 20 Hz and Ultrasonic sounds are above 20,000 Hz.
A-Weighted Sound Level, dBA	The sound pressure level in decibels as measured on a sound level meter using the A-weighting filter network. The A-weighting filter de-emphasizes the very low and very high frequency components of the sound in a manner similar to the frequency response of the human ear and correlates well with subjective reactions to noise.
Equivalent Noise Level, Leq	The average A-weighted noise level during the measurement period. The hourly Leq used for this report is denoted as dBA Leq(h).
Lmax, Lmin	The maximum and minimum A-weighted noise level during the measurement period.
L01, L10, L50, L90	The A-weighted noise levels that are exceeded 1%, 10%, 50%, and 90% of the time during the measurement period.
Day/Night Noise Level, Ldn or DNL	The equivalent noise level for a continuous 24-hour period with a 10-decibel penalty imposed during nighttime and morning hours. (10:00 pm to 7:00 am).
Community Noise Equivalent Level, CNEL	CNEL is the equivalent noise level for a continuous 24-hour period with a 5-decibel penalty imposed in the evening (7:00 pm to 10:00 pm) and a 10-decibel penalty imposed during nighttime and morning hours (10:00 pm to 7:00 am).
Ambient Noise Level	The composite of noise from all sources near and far. The normal or existing level of environmental noise at a given location.
Intrusive	That noise which intrudes over and above the existing ambient noise at a given location. The relative intrusiveness of a sound depends upon its amplitude, duration, frequency, and time of occurrence and tonal or informational content as well as the prevailing ambient noise level.

Source: Harris, Handbook of Acoustical Measurements and Noise Control, 1998.

3. **Noise is implicated in a wide range of adverse health effects.**

3.1. Chronic exposure to moderate levels of noise, below levels that cause hearing loss, can lead to a diverse set of health and physiological impacts in the general population. (Passchier-Vermeer and Passchier 2000)

3.2. Transportation-related noise causes loss of 1 million healthy years of life annually in Europe — a disease burden second only to air pollution. (Hänninen et al. 2014)

3.3. Cumulative environmental noise exposure is responsible for 61,000 disability-adjusted life years (DALYs) due to ischemic heart disease, 45,000 DALYs due to cognitive impairment in children, and 22,000 due to tinnitus. (WHO 2011)

3.4. Noise works through various mechanisms to cause adverse health effects, including:

3.4.1. *Auditory effects,* such as temporary or permanent hearing loss.

3.4.2. *Biological effects*, whereby noise, including environmental noise, induces the release of stress hormones that create responses such as inflammation and changes in heart rate, and are associated with cardiovascular disease, hypertension, arrhythmia, and myocardial infarction (Babisch et al. 1993, Babisch 2000, 2005, 2006, van Kempen et al. 2002, Stansfeld and Matheson 2003, de Kluizenaar et al. 2009, Selander et al. 2009)

3.4.3. *Extra-auditory effects*, including annoyance and extreme annoyance, sleep disturbance and resultant fatigue, accidents, injuries, cognitive impairment and cardiovascular disease, cognitive impairment in children, exacerbation of mental health disorders (e.g. depression, stress, anxiety, psychosis), and activity interference (moderate levels of noise interfere with routine activities, including having a conversation, concentrating or working). (Passchier-Vermeer and Passchier 2000, Miedema and Oudshoorn 2001, de Kluizenaar et al. 2009, World Health Organization 2009, Basner et al. 2014, Hays et al. 2016). Definitions for selected non-auditory effects amongst those listed above are as follows:

3.4.3.1. *Annoyance*: Noise annoyance is defined as "a feeling of resentment, displeasure, discomfort, dissatisfaction, or offense when noise interferes with someone's thoughts, feelings, or actual activities" (Passchier-Vermeer and Passchier 2000). Annoyance is a very common response to environmental noise, producing feelings of anger, displeasure, anxiety, helplessness, distraction, and / or exhaustion (World Health Organization 2011). "Annoyance affects both the wellbeing and quality of life among populations exposed to environmental noise." (Hays et al. 2016)

3.4.3.2. *Sleep Disruption*: A common response to environmental noise that produces some of the most severe extra-auditory effects. (Muzet 2007, World Health Organization 2011, Hume et al. 2012)

3.4.3.3. *Cognitive Impairment in Children:* Children exposed to chronic transportation noise have deficits in reading and memory, suffering the resulting losses in school performance (Evans et al. 1998, Shield and

Dockrell 2003, Evans and Hygge 2007). For instance, in a study of rail and road noise, children exposed to noise levels of 62 dBA[23] (Ldn[23]) had deficits in memory compared to those exposed to 46 dBA (Ldn) (Lercher et al. 2003).

3.4.3.4. *Cardiovascular effects:* A meta-analysis of the relationship between noise exposure and heart disease found road traffic noise to be associated with higher risk for myocardial infarction and ischemic heart disease (van Kempen et al. 2002).

4. Levels of noise that can be generated by train operations correspond to documented levels of effect, for example:

4.1. *Annoyance:* Transportation noise has been ranked among the most significant causes of community dissatisfaction. On the aggregate, the level of high annoyance in a community averages 0 percent at 45 Ldn, approximately 10 percent at 60 Ldn, and escalates to 70 percent at 85 Ldn. (Federal Railroad Administration, accessed May 27, 2016)[24]

4.2. *Sleep Disruption*: Sleep disruption effects at various noise levels have been reported by the WHO as follows (World Health Organization 2009):

- Below 30 dBA: No sleep disruption effects are observed
- 30-40dBA: Modest sleep disruption occurs
- 40-55dBA: Many adverse health effects and coping behaviors occur (e.g., sleep disturbance, insomnia, and increased use of drugs)
- Above 55dBA: Disruption is of major concern and adverse health effects are frequent, accompanied by high annoyance and sleep-disturbed/deprived, along with risk of cardiovascular disease

4.2.1. An average nighttime noise level of 65 dB will result in self-reported disturbance of sleep in about 15% percent of the population, while a single noise event at 80 dB will result in awakenings in about a third of the population (World Health Organization 2009).

4.3. *Speech Interference*: The indoor threshold for speech interference is 45dBA for steady noise, and 55dBA for fluctuating noise; the outdoor threshold ranges from 60dBA – 70dBA. (Bhatia and Puccetti, 2015; US EPA, 1979)

4.3.1. Outdoor noise levels of greater than 72 dBA will prevent normal voice level communication at unprotected exterior locations, with .5 meters of distance between the speakers. (US EPA, 1979)

4.4. *Cardiovascular effects*: Moderate levels of traffic noise (>65 dBA) have been linked to both hypertension and ischemic heart disease. (Babisch 2008)

[23] For definition see **Table 1: Definition of Acoustical Terms**
[24] https://www.fra.dot.gov/Page/P0599

4.4.1. Community noise, including traffic noise above 50–60 dBA increases the risk of myocardial infarction and cardiovascular risk was found to increase with increasing daytime noise levels above 60 dBA. (Babisch 2005, 2006, 2008, Selander et al. 2009)

4.5. *Activity interference*: Activity is disrupted indoors at a level of 45dBA Ldn and outdoor at a level of 60 dBA Ldn. (Bhatia, 2015)

4.6. *Hearing loss*: Chronic or repeated exposure to sounds at or above 85 dB can cause hearing loss (National Institute of Deafness and Other Communication Disorders 2015). Decibels between 80-105 are labeled extremely loud, whereas those above 105 dBA are dangerous. (Coaltrain Facts, 2016)

5. United States local and state standards are not completely health protective according to World Health Organization guidelines (Human Impact Partners, 2011). WHO noise exposure thresholds are much lower, for example for levels inside (30 dBA) outside (50–55 dBA) homes, as well as for classrooms (35 dBA) (Human Impact Partners, 2011).

6. Certain populations may be more vulnerable to the effects of noise exposure.

6.1. *Children* are likely more vulnerable to negative cognitive effects (van Kamp and Davies 2013). Noise can be detrimental to comprehension, memory, and attention/perception (Haines et al. 2001a, 2001b). Children who are chronically exposed to noise may have impaired cognitive development and subsequent effects on educational attainment (World Health Organization 2011, Stansfeld and Clark 2015).

6.1.1. As an example of cognitive effects of noise, a California study found that at schools within 300 meters (984 feet) of the I-710 corridor, fewer students scored as proficient or advanced for reading (13% fewer) and math (11%) on the California Standardized Test for the 2008–2009 school year. (Human Impact Partners 2011)

6.2. *People with impaired capacity or cognition* may experience greater deficits (e.g. the elderly, mentally ill, depressed, students with learning difficulties, young children, and populations with low economic standing). (van Kamp and Davies 2013)

6.3. *People with pre-existing conditions* such as cardiovascular disease and tinnitus are more at risk for health effects of noise exposure. (van Kamp and Davies 2013)

7. Coal transport is likely to generate pronounced noise.

7.1. *Trains produce particularly disruptive noise* because human reaction to noise is influenced in part by the time between noises and the "difference in loudness between a noise event and background" (Berglund et al. 1999), and most train noise is in high contrast to typical ambient conditions (Multnomah County Health Department 2013)

7.2. *Unit coal trains are substantially longer and heavier, with several more engines than freight trains,* increasing the duration of disruption and possibly the loudness. (Fox, 2015)

7.3. *Terminal activity may produce a significant amount of noise* including moving rail cars into unloading stations and unloading them. (Multnomah County Health Department 2013, Fox 2015) (Fox & Multnomah submissions – further substantiate)

7.4. *Ship transit* for coal may involve larger ships and may also be a source of noise, however this factor has not been studied and requires further review.

Description of background (ambient) noise in West Oakland

8. Baseline (ambient) noise conditions in West Oakland are high.

8.1. Transportation sources such as automobiles, trucks, and trains are the principal sources of noise in West Oakland. In addition to being subject to freeway traffic and BART noise, West Oakland is bordered on its south and west by the Union Pacific Railroad, BNSF Railroad, associated railyards, and Port of Oakland intermodal facilities, all significant noise sources affecting surrounding areas. (Lamphier-Gregory et al. 2014)

8.2. The West Oakland Specific Plan Draft EIR looked across several previous noise assessment studies in West Oakland or analogous settings (e.g., Jack London Square) to establish ambient noise levels. On the aggregate, these noise studies indicate that noise levels near unprotected major transportation sources range from CNEL 68 – 72 dBA and areas away from these sources are generally less than 65 dBA. (Lamphier-Gregory et al. 2014)

8.3. A 2010 Health Impact Assessment (HIA) for the Port of Oakland conducted by the UC Berkeley Health Impact Group estimated that the majority of West Oakland residents are exposed to ambient noise levels of 75 dB Ldn or higher based on existing conditions (See Figure 2 and Table 2). (UC Berkeley Health Impact Group (UCBHIG) 2010)

Figure 2 West Oakland Noise Contours, Port of Oakland HIA 2010

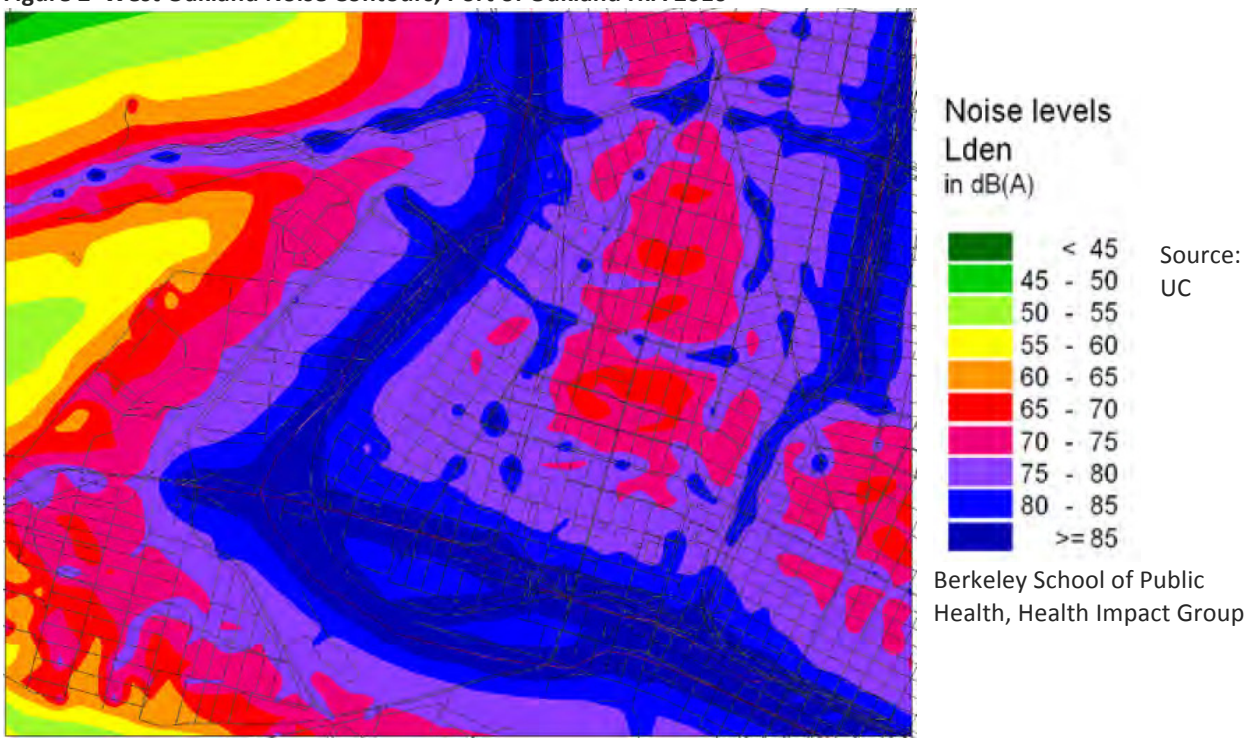


Table 2 West Oakland Population Exposure to Various Noise Levels

dB	Population Exposed	Percent of Total Population
60	247	1%
65	2,110	9%
70	6,169	25%
75	9,696	40%
80	4,707	19%
85+	1,520	6%
Total	24449	

Source: UC Berkeley Health Impact Group (UCBHIG), *Health Impact Assessment of the Port of Oakland*, University of California, Berkeley, CA, March 2010.

9. Baseline noise conditions in West Oakland are already associated with adverse health and social effects, and in some areas are already incompatible with residential development (See Table 3 for Oakland Land Use Noise Compatibility Guidelines)

9.1. The West Oakland Specific Plan Draft EIR found several areas near existing transit corridors to be "generally incompatible with residential and other noise-sensitive uses," and that of the remaining noise environments, most are considered only conditionally acceptable for residential uses (Lamphier-Gregory et al. 2014). Similarly, the Port of Oakland HIA indicates that 90% of West Oakland inhabitants live in an ambient environment of Ldn 65 dBA or higher (see Figure x and Table 7, adapted from UC Berkeley Health Impact Group (UCBHIG) 2010).

9.2. The Port of Oakland HIA (UC Berkeley Health Impact Group (UCBHIG) 2010) estimated that at baseline, in West Oakland:

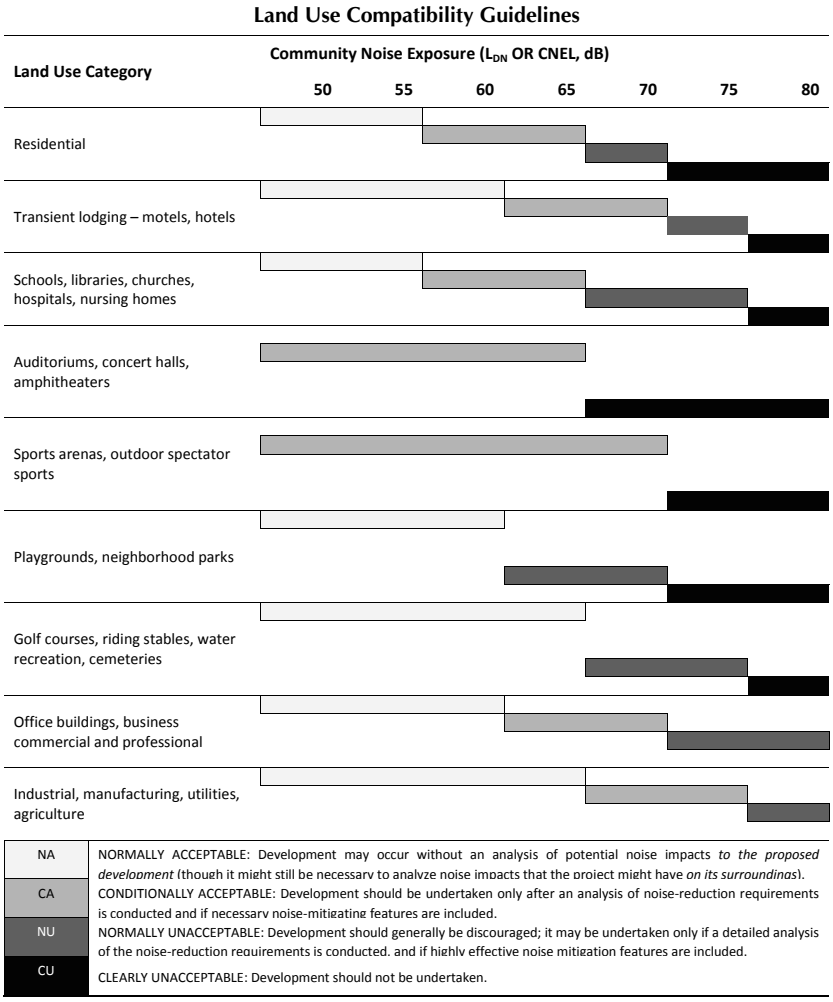
9.2.1. Greater than one in three residents are likely to be highly annoyed by noise.

9.2.2. 8 myocardial infarction deaths (15 percent of all myocardial infarction deaths) per year may be associated with noise exposure.

9.2.3. Approximately one third of residents may be at risk of sleep disturbance.

9.2.4. With an average noise exposure of 74 dB, West Oakland residents face risk of a 29 percent impairment in recall and reading, and a 4 percent impairment in recognition and attention relative to a typical 60 dB residential environment.

Table 3 Oakland General Plan Noise Guidelines for Land Use



Source City of Oakland General Plan

10. There are likely to be cumulative health impacts associated with the proposed coal export, which could involve up to 4 round trips per day of mile-long trains

10.1. Cumulative health impacts occur in part because biological / non-auditory effects (e.g., increased blood pressure, increased heart rate, vasoconstriction, changes in respiration, and arrhythmia) continue to have deleterious effects on human health even after a person "gets used to" the noise (Human Impact Partners 2011). Bhatia states that there is "no evidence that humans develop a physiologic tolerance to noise." (Bhatia and Puccetti, 2015)

10.2. Transportation-related noise in western Europe accounted for the cumulative loss of 903,000 DALYs due to sleep disturbance and 587,000 DALYs due to interference with normal function and activities. (World Health Organization, 2011)

10.3. Long term exposure to noise from road, rail, and air traffic results in physiological and psychological stress including elevated blood pressure, hypertension, ischemic heart disease, and stroke. (Münzel et al. 2014, Halonen et al. 2015, Vienneau et al. 2015)

10.4. Impact of this transient noise will be most significant when experienced during sleeping hours and for sensitive receptors, for example children in school or elderly.

Noise Exposure Assessment

11. Populations near the rails will be subject to two cumulative exposure scenarios:

11.1. The accumulation of noise exposure to trains passing through the neighborhood - annually and over the course of the 66-year lease - will create conditions of chronic noise exposure.

11.2. Noise from round-trip coal trains blasting 110 dB horns at each of 55 at-grade crossings (as per federal law[25]), will accumulate to 2 hours per day[26] of very loud noise throughout the region according to Fox's report. (Fox, 2015)

12. Extrapolating from a prototype sound study of coal trains in Washington State (Bhatia and Puccetti, 2015) (see chapter appendix), we can estimate that noise exposures will reach levels of observed effect and/or exceed established noise standards in both exposure scenarios: near or not near an at-grade crossing (horn blast). See Table 4 for noise estimated noise exposures.

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[25] Federal regulation requires locomotive horns be sounded for 15-20 seconds before entering all public grade crossings, but not more than one-quarter mile in advance.
https://www.up.com/real_estate/roadxing/industry/horn_quiet/index.htm
Field measurements show an average Reference SEL of 107 dBA at 100 feet from the track increasing to 110 dBA at 110 feet from the at-grade roadway crossing.

[26] Daily duration of train noise: 20-seconds/sounding x 55 at-grade crossings x 6 (one-way x 3 round-trip train trips/day = 6,600 seconds= 1.83 hours of noise per day that is in contrast to background (meaning greater detrimental impact). By extrapolation, the regional loud episodic sound exposure would be 670 hours per year, and roughly 4400 hours over the course of the lease.

12.1. This assessment assumes 4 new coal trains (this parameter is the maximum for the project, but allows us to extrapolate from the Washington study). For sensitivity analysis, upper and lower limits are as follows:

12.1.1. *Lower limit:* Bellingham exposures, since ambient Ldn is lower than West Oakland's, but more closely approximates Oakland in terms of total train activity.

12.1.2. *Upper limit:* Cheney exposures, since Cheney's ambient Ldn is closer to West Oakland's, but the total train activity is higher.

Table 5 Extrapolated estimates of cumulative noise exposure pursuant to adding OBOT coal trains, associated health effects, and sensitive receptors – distal / proximate to horn blast (per at-grade crossing)

	100 ft	250 ft	500 ft	1,000 ft	2-4,000 ft
Bellingham Ambient Ldn	75 / 79	65 / 71	60 / 67	56 / 62	55
Cheney: Ambient Ldn	80 / 83	74 / 77	65 / 71	60 / 67	56/61
Health effects	Serious annoyance, sleep disturbance, speech disturbance, activity interference, MI risk, possible learning and functioning disturbance, depending upon quality of indoor / classroom acoustics				
	significant speech disturbance (>65), (hearing loss at >70-75)				
Sensitive Receptors West Oakland		Residential (East Oakland)	Residential	Raimondi Park, Willow Park	Prescott Elementary, St. Patrick, St. Martin de Porres, DeFremery Park, (McClymond High)*

*Note that McClymond High is about 4,200 feet and the West Oakland Senior Center is about 5,200 feet from the tracks. At the same time, the WHO set an indoor threshold of 30 dBA above which speech intelligibility and learning disruption can occur, and so it's possible that with an outdoor level of 50 dBA that some portion of the campus experiences levels of nose that can disrupt learning.

13. Those who must be in proximity to the coal export activities will experience the greatest exposure to noise (while also being exposed to the greatest amount of air pollution – these two exposures may interact, although the science is still emerging).

13.1. In particular, residents in proximity to the tracks and terminal (especially in poor quality housing), children who must attend school, people in nearby care facilities, and people seeking accessible recreational space close to the railway and terminal have greater exposure.

13.2. Workers at the site and on the rails also have greater exposure.

13.3. *Athletes, especially the many youth athletes, who share Raimondi Park will have very high levels of combined noise and air pollution given their very close proximity to the tracks, with a high number of sensitive receptors (i.e. children and athletes).*

13.3.1. Raimondi Park is heavily used, year round. Outside of summer months, a combination of teams uses the fields 4-10P on weekdays and 8A – 10P on weekends. During summer months, the hours of use begin at 9A. Assuming roughly 75 people

per day use the fields 365 days / year = 27,375 visits per year at Raimondi. At usually 2 hours per visit (though some staff are there much longer), that's 54,750 person hours of potential exposure per year.

13.3.2. East Bay United (EBU) Soccer Club is one of the heavy users of Raimondi Park, cataloguing almost 23,000 person hours of exposure per year. Calculations are as follows:

13.3.2.1. January 1 – June 15: 75 people/day, 2 hrs per practice/day, 5 days / week, 375 people/week, 750 person hours / week, 22 weeks, approximately 16,500 person hours / year

13.3.2.2. Sept. 1 – Dec. 15: 75 people/day, 2 hrs per practice/day, 2 day/week, 150 people / week, 300 person hours / week, 14 weeks approximately 4,200 person hours / year

13.3.2.3. Summer camps – 7 hours/day x 75 people / day x 4 weeks = 2,100 person hours / year

13.3.3. Other groups that also use the field include: East Bay Warriors Football Teams, BASAC Charter School, EBSSL Adult Soccer League, and Oakland Youth Rugby.

Noise Impact Assessment

14. The prototype study (Bhatia and Puccetti, 2015) applied exposure estimates and the following exposure response functions to estimate the percent of the population that would be affected by activity interference (per annoyance) and sleep disturbance.

14.1. Percent of exposed who are highly annoyed by the increase in train noise with a threshold of 42 Ldn (Miedema and Oudshoorn 2001):

$$(7.158 \times 10^{-4} (L_{dn} - 42)^3 - 7.774 \times 10^{-3} (L_{dn} - 42)^2 + 0.163 (L_{dn} - 42))$$

14.2. Percent of exposed who experience highly disturbed sleep per the increase in train noise with threshold 42 L_{night} (Miedema and Vos 2007):

$$(11.3 - 0.55 (L_{night}) + 0.00759 (L_{night})^2)$$

15. An increased proportion, in a larger geographic area, would experience health effects related to the OBOT train activity (Table 6).

15.1. West Oakland's current noise exposure is already sufficient to interfere with activity and learning, as well as impair sleep. Exposure levels and health effects would worsen with incremental increases in rail freight transport of coal.

Table 5 Extrapolated estimates of possible cumulative impacts of noise pursuant to adding OBOT coal trains, associated health effects, and sensitive receptors – distal / proximate to horn blast (per at-grade crossing)

Impact	100 ft	250 ft		500 ft	1,000 ft	2-4,000 ft
	Bellingham –" lower limit"					
% Experiencing disturbed sleep	9.0 / 11.0	5.0 / 7.5		3.4 / 5.7	2.3 / 4.2	~2 / ~2.5-3
% Experiencing activity interference	22.7 / 30.7	7.9 / 15.9		4.5 / 10.0	2.9 / 6.2	2.5 / ~3 - 4
	Cheney – "upper limit"					
% Experiencing disturbed sleep	12.2 / 14.0	9.0 / 10.6		5.3 / 7.7	3.2 / 5.6	~2.2 / 3.7-2.8
% Experiencing activity interference	34.3 / 44.1	20.8 / 27.8		8.7 / 16.3	4.5 / 10.1	2.8-3.6 / 2.7-5.2

16. Noise mitigation options are available, but generally prove expensive.

16.1. To mitigate train noise, some cities have established quiet zones, in which safety modifications are made to public crossings to exempt trains from horn-blowing. However, these measures are expensive and shift liability from the railroad to the city. (Coal Train Facts 2012)

16.2. Prohibition of train movement outside of working hours would provide some noise relief and decrease sleep disturbance.

16.3. Maximum allowable noise levels should be adjusted down when sensitive receptors, such as schools and hospitals are present.

16.4. Physical improvements to the environment, such as sound walls, and use of sound-absorbing materials can decrease levels of noise exposure.

16.5. Title 24 of the California Code of Regulations provides for noise insulation standards for residential buildings, and can be applied when new housing is developed near the rails and terminal. Residences must be designed to limit interior noise to no more than a Ldn of 45 dB (UC Berkeley Health Impact Group (UCBHIG) 2010). This obligation would lead to an additional cost for housing developers in the future.

APPENDICES

Appendix Chapter 1: Resiliency, Vulnerability and West Oakland

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Levels of use at Raimondi Field

Emailed communication

Raimondi is a very heavily used field essentially year round. EBU is one of the heavy users where essentially we have teams out there on Mondays and Wednesdays starting September 1 through December 15 from 4 – 9 PM. Number of players/coaches/parents that are out there for this time period is 75 per day or 150 for both days. We then have the field on M-F's from January 1 – June 15, again at 75 people/day or 375 people/week.

Other groups that also use the field include:

1. East Bay Warriors Football Teams
2. BASAC Charter School
3. EBSSL Adult Soccer League
4. Oakland Youth Rugby

These organizations plus our essentially use Raimondi from 4-10 PM weekdays and 8 AM – 10 PM on weekends. All of these groups have large numbers of participants in their permitted time slots. From my experience if you assume 75 people-day essentially 365 days/year = 27,375 people/year.

Nino Borsoni, PMP
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Appendix Chapter 2: Air Quality Particulate Matter

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Figures and Additional Submissions

Letter from Doctors John Balmes and Michael Lipsett on particulate matter

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June 3, 2016

Oakland City Council
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RE: Proposed coal project at the Port of Oakland

Dear Members of the City Council:

We are two California physicians with many decades of experience in the evaluation of the human health impacts of exposure to ambient air pollution. We are submitting these comments to provide information about some potential health impacts that may result from the proposed coal train project. Below we present a brief summary of some relevant published literature (with references at the end), followed by a short description of our backgrounds and qualifications.

Principal Health Impacts of Particulate Matter Air Pollution

Particulate matter (PM) is a heterogeneous airborne mixture of solid and liquid particles, varying widely across time and space. PM levels are generally described and regulated according to the concentration of different inhalable size fractions: specifically, PM10 (particles with a median diameter less than 10 microns [or μm]) and fine particles or PM2.5 (diameter less than 2.5 μm). The principal types of PM expected from the proposed coal rail transport project -- diesel exhaust and coal dust – are only two among many sources, but from a public health standpoint, they should not be treated differently from any other type of PM. **In other words, since diesel particles and a significant portion of coal dust fall within the PM2.5 and PM10 size ranges, the health effects consistently linked with ambient PM are also likely to result from exposure to these two coal train-associated pollutants.**

Hundreds of peer-reviewed scientific articles link PM10 and PM2.5 exposure with premature mortality and with the occurrence of many serious health outcomes, including heart attacks and strokes, lung cancer, as well as hospital admissions and emergency room visits for a variety of cardiovascular and respiratory conditions (including asthma, chronic obstructive lung disease, and respiratory infections). Other well-documented effects include increased respiratory symptoms (especially among asthmatics), decreased lung function (both short- and long-term), missed days at school and work, pre-term births and other adverse reproductive outcomes. This literature has been exhaustively reviewed by the U.S. Environmental Protection Agency (2009); many articles corroborating and extending these findings have been published since then (e.g., Brook et al. 2010; Guarnieri and Balmes 2014; Hart et al. 2015; Lipsett et al. 2011; Tétreault et al. 2016).

The adverse physiological effects of PM on the cardiovascular system have been likened to those of cigarette smoke, and include low-grade inflammation and narrowing of arteries, increased tendency to form blood clots (which can cause strokes and heart attacks), and increased blood pressure. The American Heart Association considers PM2.5 as a cause of both acute events (heart attacks and strokes – sometimes within hours of exposure) and as a contributor to the long-term development of cardiovascular disease (Brook et al. 2010).

Many studies have linked PM exposure with worsening of asthma, as measured by increased symptoms and medication use, emergency room visits and hospitalizations, school absences, and decreased lung function (US EPA 2009; Guarnieri and Balmes 2014). PM 2.5 exposure causes increased oxidative stress and inflammation in the lung, which are hallmarks of asthma. Local and systemic inflammation underlie the development of many chronic diseases, not just asthma. There is some evidence that PM exposure can also cause new cases of asthma, but this is not as firmly established as that for asthma exacerbations in people who already have the disease (Guarnieri and Balmes 2014).

Diesel particles' effects on asthma and allergy have been extensively studied: they can increase allergic responses and make it easier for people who already have allergies to develop new ones. Diesel exposure also increases airway inflammation, though some people with mild, well-controlled asthma may experience less immediate inflammation from diesel exposure than others (Balmes 2011). Diesel particles are also known to contain a variety of chemicals known to cause airway inflammation and damage, including polycyclic aromatic hydrocarbons (PAHs), metals, and chemically reactive chemicals known as free radicals (IARC 2014). The International Agency for Research on Cancer (IARC - a part of the World Health Organization) has also authoritatively designated diesel exhaust as a known human carcinogen (i.e., cause of cancer – IARC 2014).

While coal mining has long been associated with devastating occupational lung disease, there are only a few studies of environmental exposure to coal dust. There is some evidence that environmental exposure may be linked with increased respiratory symptoms in children. Brabin et al. (1994) reported increased wheezing, excess cough, breathlessness, and school absenteeism among children attending primary schools located between 0.5 and 2 kilometers (km) from a dock area in England where coal and petroleum coke were unloaded and stored when compared with children attending schools 3 to 8 km away. Pless-Mulloli et al. (2000) reported increased doctor visits for respiratory conditions (but no increases in some other measures of lung disease) among children living in communities "near" opencast coal mining sites in northern England versus those living further away. A few studies examining coal mining communities in the U.S. suggest that residential proximity to coal mines may be linked to cancer incidence and to increased rates of heart, lung, and kidney disease (Mueller et al. 2015; Hendryx and Ahern 2008). However, it is difficult to conduct such environmental health studies: none of these was designed or carried out in such a way as to be able to accurately assess specific effects of ambient coal dust on human health.

However, there is a large body of evidence that coal dust is toxic. It contains some of the same harmful constituents as diesel particles -- PAHs, metals, and free radicals (Dalal et al. 1995). Laboratory studies indicate that coal dust can damage lung cells and cause inflammation in a several ways (Schins et al. 1999). In occupational settings, coal dust exposure causes severe and

often fatal chronic lung diseases. **Therefore, as with diesel exhaust, coal dust particles within the size range of regulated PM (that is PM10 and PM2.5) should not be treated differently from any other kind of PM when it comes to assessing human health risks and protecting public health.**

Our backgrounds

John Balmes, M.D., is a physician-scientist who is a Professor of Medicine at UCSF and a Professor of Environmental Health Sciences in the School of Public Health at UC Berkeley. He is an Attending Physician in the UCSF Division of Occupational and Environmental Medicine and the Division of Pulmonary and Critical Care Medicine at San Francisco General Hospital. At UC Berkeley, he is the Director of the Northern California Center for Occupational and Environmental Health and the UC Berkeley-UCSF Joint Medical Program. He is also one of the Principal Investigators of the Berkeley-Stanford Children's Environmental Health Center. Dr. Balmes has been studying the effects of occupational and environmental agents on respiratory and cardiovascular health for 35 years.

Michael Lipsett, M.D., is a physician-epidemiologist who worked on environmental health issues in California state government for nearly three decades before retiring in December 2013. He also served as an Associate Clinical Professor at the University of California, San Francisco School of Medicine. For much of his career, while at the California Office of Environmental Health Hazard Assessment, he developed the medical and public health basis for California's ambient air quality standards and conducted environmental epidemiological research, particularly in air pollution. Most recently he served as the Chief of the Environmental Health Investigations Branch in the California Department of Public Health. For many years, he was a member of the Advisory Council of the Bay Area Air Quality Management District and chaired its Public Health Committee, and served as well on the Board of the American Lung Association (Alameda, Contra Costa, Solano County affiliate). He has received several awards from government and non-governmental agencies for his work on air pollution.

We appreciate your consideration of these comments during your review of the coal rail project in the Port of Oakland.

Sincerely,

John R Balmes

John Balmes, M.D.
Professor of Medicine, UCSF
Professor of Environmental Health Sciences, School of Public Health, UC Berkeley

Michael Lipsett

Michael Lipsett, M.D. (retired)
Former Chief, Environmental Health Investigations Branch
California Department of Public Health

Response to Comments from Washington Burns M.D. Executive Director Prescott-Joseph Center

Given on Oct 14, 2015.

First, we would like to acknowledge the important contributions that Dr. Burns has made to the West Oakland community. His time and effort has provided many benefits to its citizens. Nevertheless, it is important for us to address his comments. Below we have paraphrased his main comments and provided a response to each.

Comment one: This issue is too much for Oakland to take on and coal use will continue anyway.

Response: California, in general, and the cities in the Bay Area, in particular, have been an example for the rest of the world with their progressive policies to reduce fossil fuel use. Banning coal from the Oakland Army Base is consistent with this policy and provides an example for communities around the world. In addition, this comment strikes us as the "tragedy of the commons" where individual users acting independently and according to their own perceived self-interest behave contrary to the common good of all users by depleting a shared resource (in this case the ability of the earth to bear the impacts of fossil fuel combustion).

Comment two: The publication of Pless-Mulloli, et al. (2000) regarding an open cast mining operation in England is used as evidence to state there will be no impacts on asthmatics in West Oakland.

Response: Regarding the experimental design of Pless-Mulloli, et al. (2000): This study, cherry picked from among dozens of available studies, is not relevant to the situation in West Oakland since it involves exposures from large open cast mines. In this case, two different groups were compared: those living close versus far from the mines. As pointed out by the authors, the actual individual exposures for each group are very difficult to measure given the varying distances, wind conditions and topography. In at least one comparison, the cleaner "control" group had higher PM10 (particles less than 10 microns; PM2.5, less than 2.5 microns, was not measured) concentrations than the "exposed" group. Thus, unlike the case in West Oakland where there is a very direct spatial relation between the railyard and the exposed population, the actual exposure experience will be very difficult to measure in the case of open cast mines in the central region of Britain. PM10 is much more variable over space than is PM2.5 and therefore is more difficult for a single monitor to measure accurately. It is well known in the biostatistical literature that if there is important mis-measurement of exposures, it will make it much more difficult to find an effect from the exposure, if one exists. Thus, between the larger particle size, wind and topography issues, pollution measurement in this study is quite challenging. Nevertheless, the authors report that a significant association was found between daily levels of PM10 and respiratory symptoms among asthmatics. While an interesting study, there are several other shortcomings. For example, there is no apparent control for use of medicine. It could be that the "exposed" group of asthmatics use more medicines including inhalers and corticosteroids. The latter may prevent some asthma attacks from occurring so that the "exposed" group may have the same (or even less) asthma attacks than the "control" group. In fact, there is also evidence from the study that the "exposed" group goes to the doctor more often. This could mean that there is both more disease from the coal exposure and a greater need and use of medicine for this subgroup.

In fact, it is surprising that a director of a mobile asthma clinic ignores the vast literature on the impacts of particulate air pollution on asthma, particularly in children. There are several dozen quality studies examining these effects in the peer review literature. Without going into a full literature review, we can highlight some of the

more important and well-conceived recent studies. Several of these studies were conducted in California and involve the examination of tens of thousands of subjects. Specifically, recent studies have found that PM2.5 has the following effects on asthma:

1. Prenatal or early childhood exposure was associated with asthma development by age 6 (Hsu et al. 2015; Brauer et al. 2007).
2. Increased pediatric emergency department visits for asthma, wheeze and upper respiratory infections (Strickland et al. 2016; Alhanti et al. 2016).
3. Reduced lung function in minority youth with asthma (Neophytou et al. 2016) {note that decreased lung function substantially increases the risk of various diseases at adulthood}.
4. Increased bronchitic symptoms in children with asthma (Berhane et al. 2016, McConnell et al. 2003).
5. Early or late exposure increases the risk of developing asthma in adults (Young et al. 2014; Kunzli et al. 2009).
6. Emergency room visits for children and adults (Malig et al. 2013).

Comment Three: Trust TLS to do the right thing and never let coal see the light of day.
Response: There's no reason to believe that the coal companies will do the "right" thing when they have CEOs and stockholders and others who only purpose is to maximize profit. They will aim to do whatever they can do as cheaply as possible. If it is cheaper to run coal cars without covers, which it is, this is what they would prefer. In fact, according to the BNSF website, the coal companies fought the BNSF rule requiring surfactants on all coal cars. Further, even if they use covered cars, there's no guarantee that there will be zero emissions of coal dust or that they will keep using these covers for the life of the project. Further, there is likely to be an increase in diesel emissions from fuel combustion to carry the heavier coal load. Both the coal dust and diesel will impact asthmatics.

Summary: The proposed hauling of coal through West Oakland and its unloading will increase coal dust, diesel particles and noise pollution. All of these factors have known and substantial health impacts, particularly on children with asthma. In addition, the subsequent burning of up to 10 million tons of coal per year that would be exported to other countries with minimal pollution abatement would result in additional impacts on the global climate. These impacts would be experienced locally in terms of more frequent and intense heat waves and higher levels of ozone pollution. Both of these also have known important health impacts.

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Table 1 - Air quality findings from submitted evidence

	Submissions contributing to finding (✓ = cited primary source, o = no citation) (coal support submissions are shaded)															
	Coal opposition											Coal support				
Finding	EJ	Alv	Fox	SSR	Ans	Jaf	Ost	OC	Mul	NCIO	Ahe	SB	JH	Bur	HDR	**Primary source**
Exposure																
Relative to neighboring communities, West Oakland already suffers from high levels of existing air pollution, as evidenced by the following: • In 2010, annual averages for $PM_{2.5}$ concentration in West Oakland were in excess of 11 µg/m^3, relative to state and federal standards 12 µg/m^3. • West Oakland's level of diesel particulate matter is 3 times higher than the rest of the air basin, 5 times higher than the rest of Oakland, and 7 times higher than the rest of Alameda county. • West Oakland experiences higher incident rates of conditions related to air pollution (asthma, low birth weight, diabetes, heart disease, stroke, cancer, and premature mortality).	✓			✓	o			✓		✓						CARB, 2008; CBE, 2010; OEHHA data, 2014; Rubenstein, 2014; Pacific Institute, 2003; Fujita and Campbell, 2010; Cal Dep of Pub Hlth, 2012
Coal trains emit one pound of coal dust or more per car per mile, or tens of thousands of pounds of dust lost over a single trip from Utah to the proposed terminal.	✓		✓	✓	✓	✓		✓	✓	✓	✓					U.S. Dept of Trans, 2011; Minutes: Rail Energy Trans Adv Comm, 2009; de Place, 2011; Simp Weath Assoc, 1993
Trains subject to BNSF surfactant regulations produce PM2.5 concentrations roughly twice that of normal freight via coal dust and diesel exhaust along the entire length of the trip, leading to intense spikes of acute exposure to particulate matter in surrounding areas.			✓	✓		✓	✓	✓			✓					Jaffe et al., 2015; Jaffe et al., 2014
Shipping coal out of the proposed terminal will increase airborne pollutants through (1) diesel emissions from unloading/loading and train switching activities, and (2) fugitive coal dust from wind erosion while coal is stored in trains or stockpiles.	✓			✓												AMI Environmental, 2012; Sierra Research, 2007
Coal dust contains a number of toxic metalloids and metals, including silica, arsenic, cadmium, chromium, lead, mercury, manganese, beryllium, copper, iron, aluminum, and nickel.	✓		✓		o		o			✓						Colinet, 2010; Epstein et al., 2011; USEPA, 2009a

	Submissions contributing to finding (✓ = cited primary source, ○ = no citation) (coal support submissions are shaded)															
	Coal opposition											Coal support				
Finding	EJ	Alv	Fox	SSR	Ans	Jaf	Ost	OC	Mul	NCIO	Ahe	SB	JH	Bur	HDR	**Primary source**
With proper packing, load profiling, and topping, the "vast majority" of coal dust is emitted from coal trains while they accelerate from the loading point.															○	no citation†
A study for the Tongue River Rail Project in Montana found that pollutant concentrations near coal train shipping lanes (cars were uncovered, with proper load profiling and topping agents) were below state and federal standards.															✓	US Dept of Trans, 2015
Health Impacts																
According to the WHO, EPA, and numerous epidemiological studies, adverse health effects occur at all ambient particulate matter concentrations studied to-date. That is, the relationship between particulate matter and poor health is observed even at levels below federal, state, and WHO standards.							○	○	✓	○						WHO, 2003
Acute health effects																
The preponderance of pollution-related asthma literature finds a strong link between exposure to particulate matter and all of the following in children: incident asthma, respiratory episodes due to asthma, missed school due to respiratory illness, and asthma emergency department visits.	✓		✓	✓	○		✓	✓	✓	✓	○					Ames, 2012; Brabin et al., 1994; Dockery et al., 1989; Malig et al., 2013 Ostro et al., 2009; Brook et al., 2010; Health Effects Inst, 2010; Pandya et al., 2002; USEPA, 2009b
Acute exposure to particulate matter has been shown to be related to cardiovascular disease including non-fatal heart attack and stroke.	✓		✓	✓	○		✓	✓		✓						Ames, 2012; USEPA website; Kan et al., 2003; Peters et al., 2001; Malig and Ostro, 2009; Ostro et al., 2006; Brook et al., 2010; USEPA, 2009b

	Submissions contributing to finding (✓ = cited primary source, ○ = no citation) (coal support submissions are shaded)															
	Coal opposition											Coal support				
Finding	EJ	Alv	Fox	SSR	Ans	Jaf	Ost	OC	Mul	NCIO	Ahe	SB	JH	Bur	HDR	**Primary source**
Acute exposure to particulate matter has been shown to be related to all-cause premature mortality.			✓				✓	✓		✓						USEPA website; Malig and Ostro, 2009; Ostro et al., 2006; USEPA, 2009b
Coal stored in enclosed spaces such as domed structures or covered rail cars has a documented history of spontaneously combusting. Moreover, coal dust is liable to explode when a high enough concentration is exposed to an ignition source. Both these possibilities pose significant occupational hazards to those working with coal shipments.	✓	✓			✓				✓	✓						US Dep of Energy, 1993; de Place, 2012; Hossfeld and Hatt, 2005; Atkinson, 2009; Newcastle Coal Infra Grp; US Dept of Energy, 2002
Chronic health effects																
Chronic exposure to particulate matter is associated with a number of cardiopulmonary conditions, including hypertension, COPD, chronic bronchitis, IHD, and stroke.	✓	○	✓	✓	○	✓		✓	✓	✓	○					Ames, 2012; Hendryx and Ahern, 2008; Dockery et al., 1993; Janssen et al., 2011; Brook et al., 2010; WHO website; Pope III C et al., 2002; USEPA, 2009
Multiple studies show pregnant women exposed to diesel emissions are more likely to experience complications, including spontaneous abortion and low birth weight.	✓						✓	✓								CBE, 2010; Green et al., 2009
Pollutants commonly found in diesel ($PM_{2.5}$, NO_x, and ozone) are associated with reduced lung development and reduced lung function in adolescents, with chronic exposure throughout childhood leading to permanent lung underdevelopment.	✓	○		✓	○				✓							Ames, 2012; Gauderman et al., 2004; Thaller et al., 2008; Pope and Dockery, 1992
The literature demonstrates a strong link between particulate matter exposure and cancer. Cancer risk is not just occupational, but applies to those living within proximity of port, railyard, or mining activities.		○	✓		○				✓		○					CARB, 2007; Pope III et al., 2002
Occupational exposure to coal dust over a prolonged period of time causes a number of serious respiratory illnesses: pneumoconiosis,	✓		✓	○	○				✓	✓						Colinet, 2010; Ames, 2012; Wade et al., 2011;

	Submissions contributing to finding (✓ = cited primary source, ○ = no citation) (coal support submissions are shaded)															
	Coal opposition											Coal support				
Finding	EJ	Alv	Fox	SSR	Ans	Jaf	Ost	OC	Mul	NCIO	Ahe	SB	JH	Bur	HDR	**Primary source**
chronic bronchitis, emphysema, pulmonary tuberculosis, lung cancer, and silicosis. Moreover, studies of residential areas surrounding coal mining facilities have indicated that the health effects from exposure to such operations spill over into the community at-large, with higher-than-expected rates of COPD, hypertension, heart disease, kidney disease, and cancer.																Hendryx, 2009; Hendryx and Ahern, 2008; Hendryx et al, 2007, 2010
Particulate matter exposure disproportionately harms vulnerable populations, including children, the elderly, asthmatics, individuals with low incomes, and individuals with pre-existing cardiovascular or respiratory conditions.	✓		✓	✓			✓	✓	○	✓	○					USEPA website; Malig and Ostro, 2009; Malig et al., 2013; Ostro et al., 2006, '09, '14; Morello-Frosch et al 2011; Brabin et al., 1994; Ames, 2012
Exposure to opencast mining operations in the UK did not increase respiratory episodes amongst children, and further qualitative assessment showed parents in close proximity had a more favorable opinions of the mining operations after they had been in place for an extended period of time.									✓					✓		Moffatt and Pless-Mulloli, 2003; Pless-Mulloli et al., 2000; Pless-Mulloli et al.2001
Ecosystem impacts																
Coal dust and coal leachates can have a number of detrimental effects on the aquatic ecosystems of waterways bordering rail lines and the terminal, including but not limited to: • Damage to plants/animals living close to the surface of the water. • Reduced development of aquatic life due to suppressed photosynthetic potential, clogged respiratory/digestive organs, and settling of coal onto the floor of the waterway. • Increased acidity (due to coal's sulphur content) and trace metal concentration.	✓		✓				○			✓						Ahrens and Morrisey, 2005; Campbell and Devlin, 1997; Johnson and Bustin, 2006
Coal dust and coal leachates negatively impact soil by increasing its heavy metal concentration and altering its hydrology, interrupting the life cycles of everything from nitrogen-fixing lichens to animals that rely on plant growth for nourishment.			✓							✓						Bounds and Johannesson, 2007; Spencer, 2001; Piechota et al., 2002

Appendix Chapter 3: Assessment of Mitigations for Fugitive Coal Dust

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Other materials

Memo from LoraJo Foo to City of Oakland regarding rail car covers for coal

To: Claudia Cappio, Assistant City Administrator
Honorable Mayor Libby Schaaf
Oakland City Council
City Attorney Barbara Parker

From: Lora Jo Foo
No Coal in Oakland

Date: June 2, 2016

Subject: Covers for rail transport of coal

I. ECOFAB COVER FOR RAIL TRANSPORT OF COAL HAS NEVER BEEN FIELD TESTED FOR COAL DUST EMISSIONS NOR HAS IT RECEIVED FRA APPROVAL

In responses to concerns raised by the public that the transport of coal by rail through Oakland will endanger the health and safety of Oakland residents, Terminal Logistics Solutions (TLS) has repeatedly stated, most recently in its May 22, 2016 press advisory, that:

> Any coal that may be shipped through Oakland Global will not emit coal dust – in fact, coal will never see the light of day. Rail cars will be covered from their point of origin using proven technology, an elaborate underground transloading system, enclosed dome storage, and a completely encapsulated operation.[27]

The proven technology that TLS was referring to for rail car covers is a design by EcoFab. At a press conference on May 23, 2016, when asked whether TLS was doing testing to be sure no coal dust escaped the rail cars, Jerry Bridges, CEO of TLS, responded:

> "FRA last year approved these particular covers, Ecofab is the name of the company, they approved these rail car covers for the transportation of coal."

Bridges also told the East Bay Times that EcoFab tested the covers.[28]

Contrary to Bridge's assertions, in fact, EcoFab has never tested the covers to determine their effectiveness in preventing leakages of fugitive coal dust. Nor has the Federal Rail Administration (FRA) approved EcoFab covers.

In the week of May 23, I interviewed Doug Bock, EcoFab's Vice President of Marketing and Sales, and also communicated with him by email regarding covers for rail transport of coal.

Bock stated in an email dated May 27, 2016 regarding Bridges' press conference statement that:

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[27] http://www.businesswire.com/news/home/20160522005047/en/MEDIA-ADVISORY-Oakland-Community-Civic-Leaders-Voice

[28] See Erin Baldassari, Supporters of shipping coal through Oakland say it will bring jobs, East Bay Times (05/24/2016) http://www.eastbaytimes.com/breaking-news/ci_29929850/supporters-shipping-coal-through-oakland-say-it-will

> If Jerry has said that the FRA has approved our cover for coal, he is mistaken. Ecofab has at no time sought or received FRA approval for the cover we have presented to TLS.[29]

In our phone conversation on May 24, 2016, Bock stated that EcoFab has never done specific testing of its covers for coal transport.

I also interviewed and communicated by email with Dr. Harold Blankenship, Mechanical Engineer in the Office of Railroad Safety of the FRA about the approval process for coal car covers. He made clear that the FRA does not issue approvals for rail car covers and is not involved with testing for coal dust emissions. In an email dated May 26, 2016,[30] Dr. Blankenship responded to my questions as follows:

> Q: Does the federal rail authority have to "approve" these covers before they are made commercially available?
>
> Ans: Yes and No. The FRA and our Canadian Regulatory partner—Transport Canada work to enforce safety on all north American railroads. We do not "approve" coal car covers, HOWEVER, if for instance a company designs a "cover" and wants a safety review, the FRA will do this as a courtesy, with the intent to see that such a cover does not interfere with employee safety, block access to side ladders, end ladders, sill steps, handbrakes, or introduce an unacceptable risk to railroad employees.
>
> Q: Is testing for leakage of fugitive coal dust required in the approval process?
>
> Ans: No, FRA does not get involved with any fugitive coal dust emission tests as far as I know.
>
> Q: Are there any other companies who have received approval or whose approval is pending?
>
> Ans: FRA does NOT approve covers EXCEPT when requested to provide guidance for a particular design as it relates to the safety appliance arrangement contained in the proposal. Once reviewed, the FRA may issue a letter that the proposed design may or may not comply with current safety appliance regulations contained in AAR S-2044 and Title 49 Code of Federal Regulations (CFR) Part 231.

In summary, the proven technology that Bridges claims exists for rail car covers for coal is a mirage. EcoFab never tested its cover to determine if it is effective in preventing coal dust leakage. And the FRA performs safety reviews of rail car covers but does not review whether the covers prevent leakage of coal dust. Thus, neither FRA nor any federal agency has established standards for field testing the effectiveness of coal covers' containment of coal dust.

II. OF THE COVERS FOR COAL TRAINS NOW COMMERCIALLY AVAILABLE, NONE HAVE BEEN FIELD TESTED AND NONE HAVE MADE IT TO MARKET.

To determine whether covers for coal train cars are used anywhere in the U.S., whether any are commercially available, and whether they have been tested for their effectiveness in controlling fugitive coal dust, I interviewed the companies that have reportedly designed rail car covers for coal.

Dave Gambrel, a coal transportation consultant and former director of transportation for Peabody Energy, in a 2013 article in Coal Age listed the five companies that have worked on "different rail car cover designs to prevent

[29] The full text of Doug Bock's email response is attached below.
[30] The full text of Dr. Harold Blankenship's email is attached below.

coal dust from flying out the tops of rail cars."[31] I reached these companies by phone and posed these questions to them:

1) Why did you decide to go into this product line?
2) Did you go beyond the design stage? Did you produce a prototype? Is this design now commercially available?
3) Did you do testing to determine if the covers prevented leakage of coal dust? If yes, what were the results?

In summary, while three of the five companies state they have commercially available covers, none have manufactured any to date. While two companies performed functionality tests, that is, to determine if the covers opened and closed as designed, none of these covers has been field tested to determine their efficiency in keeping coal dust from escaping during transport. Below is a summary of the responses from the five companies to the questions I posed to them.

1. Strategic Rail System (Rush-Co) (http://www.rush-co.com/srs-rail/)

On May 23, 2016, I interviewed Evan Jones, President of Strategic Rail System (SRS). SRS was approached by Union Pacific (UP) to design covers for coal cars. Around four years ago, SRS built seven prototypes and tested them on UP lines. SRS designed covers that would automatically open and close for quicker loading and unloading, using a rotary system, not bottom dump. Anticipating that the federal government would soon adopt a regulation requiring covers of coal train cars, SRS bought a plant to gear up for production. Its covers were commercially available. But no regulation was adopted so there was no demand for the covers. SRS mothballed the project. The field testing that was done on UP lines was for functionality, that is, to determine if the covers opened and closed as they were designed to do. The covers worked as designed. However, one issue remained and that was how long the solar-powered batteries that are mounted on each car/cover to open and close the covers would last. SRS did not perform any field tests to determine the effectiveness of the covers in preventing leakage of coal dust.

2. CoalCap (Global One Transport) **(**http://www.coalcap.com/)

On May 23, 2016, I interviewed Jason Dial and Darrell Dial of Global One Transport (GOT). BNSF asked GOT to design covers to test and use for the export market. Five years ago, they built a cover and tested it from the Powder River Basin to Ohio. They had one test car behind the locomotive. They made several trips logging approximately 40,000 miles. They tested for functionality and it was a success – the cover stayed on the car and rotated fine. FRA has asked for certain modifications on their design, including placing handholds on the side of the cars. While Darrell Dial claims that dust is 100% contained, he did not perform field testing for coal dust emissions. He did videotape from time to time and saw no coal dust escaping and saw no dust on top of the covers or anywhere on the covers. When asked whether he might not have seen coal dust because it may have blown away during transport, he admitted that was possible. GOT's product is "commercially available" but they won't go into production until they receive an order.

3. CleaRRails, LCC

On May 23, 2016, I interviewed Mark Pettibone of CleaRRails. In 2015, his design (Coal Guard) received approval for safety from the FRA. He doesn't have a prototype yet. He hasn't done modeling for whether or not coal dust will be 100% contained. While other companies' covers have two doors that come off on the side of the car, his is

[31] http://www.coalage.com/departments/transportation-tips/2736-coal-dust-control-in-the-pacific-northwest.html#.VzuPOGZrXhO

a front-to-back design. A canister sits on either the front or back of car with a rolled up aluminum cover, like a garage door.

4. EcoFab (http://www.ecofab.com)

On May 24, 2016, I interviewed Doug Bock of EcoFab. A Utah coal mining company approached EcoFab about covers for coal cars. EcoFab adapted an existing cover, the Roto Cover, for transporting coal. The existing cover has been used for 40 years in the transport of lead, copper, zinc and low level radioactive material. Because TLS plans for bottom dump and not rotary cars, EcoFab adapted the Roto Cover for coal. The existing cover lifts off. The cover for coal is the same cover but is hinged and opens automatically. It is fixed permanently on the train car and removed only for preventative maintenance. EcoFab has never done specific testing for covers for coal. For that matter, it has never tested the existing covers used for transport of lead, copper and zinc to determine if dust or particles from these commodities have escaped during transport. As stated above, in an email dated May 27, 2016, Bock stated that EcoFab has at no time sought or received FRA approval for the cover it presented to TLS.

5. Structural Composite of Indiana (United Rail Covers) (http://www.railcarcovers.com)

URC designed three types of covers. But a year ago, the new owner of the company decided to drop the product line. I was not able to reach anyone at the company who was involved in designing the covers.

III. CONCLUSION

Coal dust can break down to as small as PM2.5. According to the California EPA and World Health Organization, there is no safe level of exposure to PM2.5. Therefore, rigorous testing is needed to determine if the covers that are now commercially available can prevent the escape of particles this small. However, as my interviews with four of the five companies that have designs and/or prototypes for coal covers reveal, none of them has done field testing to determine their effectiveness in preventing coal dust from escaping during transport.

For around four decades, railroads have been using covers for the transport of grain, fertilizer, copper, zinc, lead and other commodities. Tests for fugitive dust for the above commodities may or may not have been done at some point. We do not know if these covers are effective in preventing the escape of dust of these commodities. Even if they are, we don't know if the covers would work as effectively for coal dust. EcoFab's Roto Cover has been adapted to transport coal. TLS has stated that it plans to use this cover. While this cover may have been used to transport other commodities for decades, will the adapted version for coal do what it was designed to do, that is keep coal dust from escaping? Moreover, with covered coal cars, is there a potential for explosive concentrations of coal dust to form inside the containment? Might a blast occur from a static electricity discharge or other accidental source of ignition? Without field testing over a long period, we do not know.

Numerous questions remain unanswered because no such field testing has been done. Do these other commodities break down to as small as PM2.5? Can the seals on covers keep PM2.5 from leaking out? With particles this small, can the naked eye even see them escaping from the cars? How long do the seals last when coal rather than grain is the commodity? Without field testing over a period of time, we don't know how the covers will perform over time and in differing weather. Will they freeze up or malfunction when there is snow or ice or rain? Will they deform or twist or turn in the wind? Will they be as effective on the current fleet of train cars as on the latest generation of cars? Without field testing over a period of time, we do not know the answers to these questions.

EMAIL CORRESPONDENCE ON COVERS FOR COAL TRAINS

From: "Doug Bock" <DBock@ecofab.com>
Date: May 27, 2016 1:03 PM
Subject: Ecofab Covers
To: "lora jo foo" <ljfoo70@gmail.com>

If Jerry has said that the FRA has approved our cover for coal, he is mistaken. Ecofab has at no time sought or received FRA approval for the cover we have presented to TLS. Having said that Ecofab did receive approval for covering and containing low level radioactive material with the very same cover. In 1994 the US Department of Transportation (DOT) determined that the Ecofab Cover System met the criteria for a closed transport vehicle as specified in "Title 49 CFR 173.403 (c)." The approval of our cover system was sought and achieved by our customer at the time.

From: **lora jo foo** <ljfoo70@gmail.com>
Date: Fri, May 27, 2016 at 11:09 AM
Subject: Re: Covered coal cars
To: Doug Bock <DBock@ecofab.com>

Thanks for quick response. At a press conference earlier this week, when asked about whether TLS was doing testing to be sure no coal dust escaped the rail cars, Jerry Bridges responded:

> "FRA last year approved these particular covers, Ecofab is the name of the company, they approved these rail car covers for the transportation of coal."

I reviewed my notes and thought you said EcoFab did not seek FRA approval. Is that correct? Did Bridges misunderstand?
lora jo

From: **Doug Bock** <DBock@ecofab.com>
Date: Fri, May 27, 2016 at 10:53 AM
Subject: RE: Covered coal cars
To: lora jo foo <ljfoo70@gmail.com>

Yes we have spoken to and given a presentation to Terminal Logistics Solutions. Yes it was a Utah based mining company.

From: **lora jo foo** <ljfoo70@gmail.com>
Date: Fri, May 27, 2016 at 10:37 AM
Subject: Covered coal cars
To: Doug Bock <DBock@ecofab.com>

Dear Doug,

We spoke earlier this week about covers for coal train cars. I have two follow up questions I hope you can answer. You said that it was a mining company that approached EcoFab about your covers. Has anyone from Terminal Logistics Solutions, TLS, the company that will build and operate the Oakland export terminal contacted you or anyone else in your company to inquire about the covers? The principles of TLs are Jerry Bridges and Omar Benjamin. And can you tell me which mining company contacted you about the covers? Was it a Utah company? Any assistance would be greatly appreciated.

Lora Jo

From: **Blankenship, Harold (FRA)** <harold.blankenship@dot.gov>
Date: Thu, May 26, 2016 at 4:53 AM
Subject: RE: Covers for coal train cars
To: lora jo foo <ljfoo70@gmail.com>

Lora Jo,

Before we begin, I think I should give you some background as to my expertise, resume, etc.

I am a registered professional engineer with an electrical engineering degree, a mechanical engineering degree, an MBA and doctorate in operations management.

2. I spent 30 years with Norfolk Southern Railroad in a variety of management positions in the operating (mechanical and transportation) departments.

3. At present I have been with the FRA here in Washington, DC for 16 years, so basically I have 46 years of "hands on" railroad experience.

4. All my work is centered around "Railroad Safety" and regulation enforcement.

I am attaching a copy of my current position description and primary responsibilities here at the U.S. Department of Transportation Federal Railroad Administration (FRA).

Answers/Responses to Lora Jo's questions:

1. What was the impetus for the proposed rule? Ans. There are many federal agencies that may have at some point explored whether a "rule" was needed to govern the transport of coal, (EPA? DOT? Commerce?) so, without seeing a "hard copy" of a proposed rule, it would be hard to make any assumption here. Again, why was the "rule" not pursued? Without "seeing" what was proposed we cannot accurately give an opinion as it would be conjecture only.

2. Does the federal rail authority have to "approve" these covers before they are made commercially available? Ans. Yes and No. The FRA and our Canadian Regulatory partner—Transport Canada work to enforce safety on all north American railroads. We do not "approve" coal car covers, HOWEVER, if for instance a company designs a "cover" and wants a safety review, the FRA will do this as a courtesy, with the intent to see that such a cover does not interfere with employee safety, block access to side ladders, end ladders, sill steps, handbrakes, or introduce an unacceptable risk to railroad employees.

3. Is testing for leakage of fugitive coal dust required in the approval process? Ans. No, FRA does not get involved with any fugitive coal dust emission tests as far as I know.

4. Are there any other companies who have received approval or whose approval is pending? Ans. FRA does NOT approve covers EXCEPT when requested to provide guidance for a particular design as it relates to the safety appliance arrangement contained in the proposal. Once reviewed, the FRA may issue a letter that the proposed design may or may not comply with current safety appliance regulations contained in AAR S-2044 and Title 49 Code of Federal Regulations (CFR) Part 231.

5. Has EcoFab applied for approval of its covers? Ans. Without a file number or correspondence control number, I cannot tell whether the EcoFab cover has received an FRA safety appliance review.

From: **lora jo foo** <ljfoo70@gmail.com>
Date: Wed, May 25, 2016 at 11:54 AM
Subject: Covers for coal train cars
To: harold.blankenship@dot.gov

Dear Dr. Blankenship,
I left a voice message and thought I'd email you my questions for you to consider. I am assisting Dr. Heather Kuiper who coordinates an independent Public Health Experts Panel assessing evidence to determine the health impacts of the transport of coal from Utah to Oakland, CA. Their conclusions will be submitted to the Oakland City Council who is considering an ordinance to ban or regulate coal. One of the issues the council will look at is whether there are measures that would prevent leakage of fugitive coal dust during the rail transport of coal. Here's my questions:

1) A few years back a federal agency was considering adopting a rule requiring all coal trains be covered. In the end, no rule was issued. What was the impetus for the proposed rule? And why was the rule not pursued?
2) I have interviewed four companies who have designed covers for coal train cars. Does the Federal Rail Authority have to approve these covers before they are made commercially available? Is testing for leakage of fugitive coal dust required in the approval process? One of the companies stated that they did not need FRA approval for their covers since they've been used for decades for other commodities such as zinc, lead, and copper. I understand that Mark Pettibone's ClearRrails covers were FRA approved and that CoalCap's (Global One Tranport) approval is pending. Are there any other companies who have received approval or whose approval is pending? In particular, has EcoFab applied for FRA approval of its covers?

I can be reached at 510-842-0647 or 510-282-9454. Looking forward to speaking with you. Lora Jo

Appendix Chapter 4: Hazardous Toxics Accompanying Coal Dust

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Appendix Chapter 5: Local Impacts of International Combustion of Coal

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Appendix Chapter 6: Responses to Developer Comments on Coal Dust

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Appendix Chapter 7: Occupational and Environmental Hazards of Coal Transport and Handling

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Appendix Chapter 9: Noise Effects of Coal Transport and Handling in Oakland

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Figures and Tables

Table 4 Parameters For Noise Model Everett-Bellingham Rail Line at Bellingham

	Bellingham			Cheney		
Train Type	Coal	Freight	Passenger	Coal	Freight	Passenger
Locomotives per train	5	5	2	5	5	2
Length of Rail Cars (feet)	7300	8000	850	7300	8000	1020
Average Speed	30	30	45	30	30	45
Wheel flats (%)	10%	10%	10%	10%	10%	10%
Rail type	Jointed	Jointed	Jointed	Jointed	Jointed	Jointed
Elevated Tracks	No	No	No	No	No	No
Sound Walls	No	No	No	No	No	No
Building Rows	One Row / 250 ft	One Row / 250 ft	One Row / 250 ft	One Row / 250 ft	One Row / 250 ft	One Row / 250 ft

ENVIRONMENTAL, HEALTH AND SAFETY IMPACTS

OF THE

PROPOSED

OAKLAND BULK AND OVERSIZED TERMINAL

Prepared
for
Sierra Club

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by

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INTRODUCTION

The California Capital Investment Group (CCIG) has entered into a 60-year lease with the City of Oakland to redevelop the Oakland Army Base. As part of this larger project, located within the Port Authority Outer Harbor in Oakland in the West Gateway Complex, there is a proposed terminal called the Oakland Bulk and Oversize Terminal (OBOT or Terminal).[1] The leasable area consists of 12.45 acres of land area and 7.86 acres of wharf. CCIG currently has an exclusive option agreement with Terminal Logistics Solutions (TLS) to develop the OBOT.[2] Thus, CCIG is the long-term lease holder and TLS is the tenant of CCIG.

The only publicly available design information on this Terminal is a July 15, 2015 Basis of Design (BOD) report (7/16/15 BOD)[3] and a series of "DRAFT" "conceptual drawings" showing the possible layout for a two commodity bulk terminal.[4] The information in these sources could change significantly as design proceeds, as funding is firmed up for the project, and during acquisition of the many permits that will be required. My comments in this report are based on the 7/16/15 BOD, conceptual drawings, and various news reports. Thus, they are subject to revision as the Terminal design is finalized. My conclusions reached in this report from reviewing this material are as follows:

- **Terminal Design:** The recently posted Basis of Design plans are conceptual, meaning they can change at any time. More specific plans will be needed to obtain permits such as air quality permits from BAAQMD. There are no enforceable conditions requiring any of the potential controls outlined in these materials, e.g., covered rail cars, enclosed storage piles and conveyors, etc.

- **Design Drawings**: The design drawings indicate that the material handling equipment – storage domes and sheds, conveyors, loaders, etc. -- will not be located in an enclosed structure. Thus, there will be emissions of PM, PM10, and PM2.5 from all of the material handling equipment. Without more specific plans, it is not possible to quantify emissions.

- **Water Usage and Pollution:** This project will be a major user of California's scarce water if it handles coal or other dusty material. Water is required to control dust during rail car unloading, at storage piles within enclosures, at drop points, and during ship loading. Based on experience at other terminals, and assuming throughput of 9.9 million tons per year of coal, 79.2 million gallons of water would be required every year to control dust. Per capita water use in Oakland is only 71.7 gallons per person per day.

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[1] http://www.oaklandglobal.com/index.php/project/about/project-overview.

[2] *See* FAQ, http://tlsoakland.com/faq/.

[3] FDR, Basis of Design, Oakland Bulk and Oversized Terminal, California Capital Investment Group, Preliminary Engineering, July 16, 2015, http://tlsoakland.com/pdf/4.pdf.

[4] Conceptual Drawings, http://tlsoakland.com/pdf/19.pdf.

Thus, the water required to control dust at the proposed Terminal could supply over 3,000 Oakland residents every year. In the middle of a record-setting state drought, which exporting and burning coal will further exacerbate, this is not an appropriate use of Oakland's limited water supply. Further, the design plans have no information on how wastewater containing coal dust will be disposed. If discharged into San Francisco Bay, it could have many detrimental impacts on water quality and aquatic organisms.

- **Coal Dust:** As CCIG's[5] and TLS's[6] recent submissions seem to indicate, the coal rail cars will most likely be uncovered. The coal loss from an uncovered bottom unloading car during a typical 400 mile trip is 45 lb from the bottom and 600 lb from the top, for a total of 645 lb per car.[7] Up to 3% of the coal loaded into a coal car can be lost in transit, which for a coal car carrying 121 tons would be 3.63 tons/car or more than 7000 lbs/car. Assuming 3 trains/day, up to 68,500 tons/yr of coal dust could be emitted from trains carrying coal from Utah to the Terminal. Assuming entry at Donner Pass, the shortest route, at least 200 miles of this route are in California. Thus, about 27% of the coal dust or about 18,300 tons/yr could be released within the state in communities like Sacramento, Davis, Richmond, Berkeley, Emeryville, and Oakland. Coal dust includes fine particles, both PM10 and PM2.5,[8] which are directly linked to health problems, including premature death, heart attacks, asthma and other problems. Coal dust can also contaminate air, water and soil, and adjacent homes, schools, and other buildings.

- **Diesel Particulate Matter:** The unit trains importing coal will be powered by up to five locomotives, which emit diesel particulate matter, a potent carcinogen that will pose significant public health risks in communities along the rail lines and adjacent to the Terminal.

- **Traffic, Noise, Vibration, Visual Impact:** The unit trains importing coal and the Terminal itself would also result in significant traffic, noise, and vibration impacts.

- **Mitigation:** None of the impacts that I discuss in this report were anticipated in the CEQA review of this Project. Further, none of the mitigation measures attached in the Sept. 8, 2015 Stice & Block Letter from the project's CEQA review[9] would address these impacts. Rail car coal dust, for example, is not regulated by any of the permits that the Terminal must obtain.

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[5] Letter from David C. Smith, Stice & Block, LLP, to Sabrina Landreth, City of Oakland, Re: September 21, 2015, Oakland City Council Public Hearing, September 8, 2015 plus attachments (Sept. 8, 2015 Stice & Block Letter).

[6] Edward J. Liebsch and Michael Musso, HDR Engineering, Oakland Bulk and Oversized Terminal Air Quality & Human Health and Safety Assessment of Potential Coal Dust Emissions, September 2015 (Sept. 2015 HDR Report).

[7] Minutes, Rail Energy Transportation Advisory Committee, September 10, 2009, http://www.scribd.com/doc/129350651/Surface-TransMinutes-9-10-09-1.

[8] Daniel Jaffe and others, Diesel Particulate Matter and Coal Dust from Trains in the Columbia River Gorge, Washington State, USA, Accepted for publication in Atmospheric Pollution Research, April 23, 2015.

[9] Sept. 8, 2015 Stice & Block, Ex. A.

My resume is included in Exhibit 1 to these comments. I have over 40 years of experience in the field of environmental engineering, including air emissions and air pollution control; greenhouse gas emission inventory and control; air quality management; water quality and water supply investigations; hazardous waste investigations; hazard investigations; risk of upset modeling; environmental permitting; nuisance investigations (odor, noise); environmental impact reports/statements, including California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA) documentation; risk assessments; and litigation support.

I have M.S. and Ph.D. degrees in environmental engineering from the University of California at Berkeley with minors in Hydrology and Mathematics. I am a licensed professional engineer (chemical, environmental) in five states, including California; a Board Certified Environmental Engineer, certified in Air Pollution Control by the American Academy of Environmental Engineers; and a Qualified Environmental Professional, certified by the Institute of Professional Environmental Practice.

FACILITY DESIGN

The design capacity of the Terminal is reported in the 7/16/15 BOD as 9.9 million tons/yr (MT/yr), with a stabilized throughput of 75% of design or 6.9 MT/yr for two commodities, designated Commodity A and B.[10] Prior information posted on the applicant's website suggested a significantly higher throughput, 26.3 MT/yr.[11]

The commodities will be shipped in Handymax, Panamax, and Capesize[12] vessels. No dredging is anticipated to accommodate these vessels, assuming the Capesize vessels are lightly loaded to 143,000 tons.[13] The rail cars will have a net capacity of 121 tons and are described as "North American Covered Hopper Cars equipped with removable, fiberglass covers".[14] The current design plans suggest that most conveyors will be enclosed, with the possible exception of pipe conveyors connecting the railcar dumper to storage. Commodity A will be stored in a series of longitudinal stockpiles located within a "storage building"[15]. Commodity B will be stored in top-filled, concrete storage domes vented to a dust collection system.

The design calls for trains of 104 railcars each (referred to as "unit trains" in this report) to import these commodities. The analysis below indicates that two to three unit trains of 104 railcars each, potentially all carrying coal, will visit the Terminal every day the Terminal is operating or 362 days per year, assuming the design throughput in the 7/16/15 BOD. However,

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[10] 7/16/15 BOD, p. 1, Sec.2.2.

[11] Oakland Global, Project, http://www.oaklandglobal.com/index.php/project/about/project-overview reports handling up to 12, 50-car trainloads per day. Assuming a net capacity of 121 tons per car (7/16/15 BOD, Table 9-1), this amounts to: 12 x 50 x 121 x 362 day/yr = 26,281,200 ton/yr.

[12] A capsize vessel is too large to fit through the Panama Canal and must sail around a cape.

[13] 7/16/15 BOD, Table 8-1.

[14] 7/16/15 BOD, Table 9-1.

[15] Drawing BMH-142, Commodity A Storage Building Section.

if the throughput reported in the Project description of 26.3 million tons of coal per year is assumed, many more unit trains would visit the Terminal each day.

Commodity A

Commodity A is characterized as "very dusty, exhibits spontaneous combustion behavior, potentially explosive".[16] This description coupled with other information in the 7/16/15 BOD, Table 9-1, indicates that Commodity A is most likely coal. This is supported by investigative news reports and e-mail correspondence, identifying Utah coal as the likely source.[17] Commodity A will be blended, suggesting coal from different mines or seams will be blended during loading at the Terminal to meet import requirements.

Commodity A railcars are expected to be bottom dump aluminum construction, closed-top hopper cars with a cargo capacity of about 121 tons.[18] Thus, a train carrying Commodity A will carry 12,584 tons[19]. As 75% of the Terminal design throughput is designated for Commodity A, about 2 unit trains per day carrying coal will visit the Terminal.[20]

Commodity B

Commodity B will have a design throughput of 1.7 MT/yr[21] and is characterized as "very dusty, hygroscopic."[22] Hygroscopic materials absorb water from the air and include many materials including coal, as well as soda ash, cellulose fibers, many fertilizers, salts, and

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[16] 7/16/15 BOD, Table 9-1.

[17] Project Could Transform Local Coal Market to International, The Richfield Reaper, April 7, 2015 ("The purchase of Sufco by Bowie [Resources] is what's driving all of this,"…He said Bowie is interested in expanding its coal shipping capacity to international markets, which would make the coal industry in Utah viable over a longer period of time….By purchasing a portion of the port's capacity, the four partner counties would be able to use 49 percent of an estimated 750,000 tons of shipping capacity each year to ship coal and other products."), http://www.richfieldreaper.com/news/local/article_e13121f0-dd67-11e4-b956-3ff480cc1929.html; Darwin BondGraham, Banking on Coal in Oakland, East Bay Express, August 19, 2015, http://www.eastbayexpress.com/oakland/banking-on-coal-in-oakland/Content?oid=4463888; Utah Wants to Send Trainloads of Coal to California Ports, AllGov California, http://www.allgov.com/usa/ca/news/california-and-the-nation/utah-wants-to-send-trainloads-of-coal-to-california-ports-150428?news=856347; Brian Maffley, Utah Coal: California, Here It Comes – And Not Everyone is Happy, August 14, 2015, The Salt Lake Tribune, http://www.sltrib.com/home/2425141-155/utah-coal-california-here-it-comes; Doug Oakley, Unlikely Partners: Utah Investing $53 Million to Export Coal through Oakland Port, San Jose Mercury News, April 24, 2015; Confidential Communications: (1) cjarrett02@gmail.com to Brody & Amber Keisel, April 8, 2015 ("…the script was to downplay coal, and discuss bulk products and a bulk terminal…); (2) Brody Keisel to Steve Frischknect, April 8, 2015, attaching CIB Presentation; (3) Jeff Holt to Jae Potter, April 24, 2015.

[18] 7/16/15 BOD, p. 12, Sec. 12.1.1.

[19] Amount of coal carried per train: 104 rail cars x 121 tons/car = 12,584 tons/train.

[20] The maximum number of unit trains carrying Commodity A per day = $0.75(9.92 \times 10^6$ ton/yr)/12,584 ton/train = 591 unit trains/yr. As the Terminal will operate 362 days/yr (7/16/15 BOD, p. 5), this means that on average,591/362 = 1.6 unit trains per day or up to 2 unit trains carrying Commodity A will visit the Terminal every day the Terminal is operating.

[21] 7/16/15 BOD, Table 6-1.

[22] 7/16/15 BOD, Table 9-1.

limestone. Commodity B railcars are expected to be steel construction, closed top, bottom dump hopper cars, with a cargo capacity of about 99 tons.[23] A train carrying Commodity B will import 10,296 tons per unit train[24]. Commodity B will not be blended. As 25% of the Terminal design throughput is designated for Commodity B, about one unit train per day on 241 days will carry this unidentified material to the Terminal.[25]

While two separate materials are identified, the design of the facility and the lack of any enforceable conditions would allow 100% of the throughput to be coal.

Dust Control

The BOD indicates the facility will use Best Control Technology (BCT) to control emissions. Public relations information[26] indicates all commodities handed at the Terminal will be:

- transported from origin to the Terminal in specially designed covered rail cars;
- discharged from the covered rail cars into an enclosed underground unit with dust control/collection technology;
- moved within the Terminal in enclosed conveyance systems with dust control/collection technology;
- stored within enclosed dome storage unit(s) with dust control/collection technology; and
,
- loaded onto the vessels using enclosed state-of-the-art ship loaders with dust control/collection technology.

Commodity A will be stored in a series of covered longitudinal stockpiles and will be reclaimed using dozers. Dust will be controlled by dry fog and/or water spray at the covered railcar dumper building, covered bulk material storage buildings, enclosed transfers, enclosed/covered conveyors, and dry fog and/or water spray at transfer points and stockpiles.

Commodity B will be stored in two concrete storage domes equipped with a dust control system and reclaimed by gravity onto a series of reclaim conveyors in above-ground tunnels underneath the domes. Dust will be controlled using the following:

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[23] The 7/16/15 BOD, Table 9-1 indicates a net capacity of 121 tons for railcars importing both Commodities A and B.

[24] Amount of Commodity B carried per unit train: 104 cars/train x 99 ton/car = 10,296 tons/unit train.

[25] Maximum number of unit trains carrying Commodity B per day = $0.25(9.92 \times 10^6$ ton/yr)/10,296 ton/train = 241 unit trains/yr. As the Terminal will operate 362 days/yr (7/16/15 BOD, p. 5), this means that one unit train carrying Commodity A will visit the Terminal on 241 days.

[26] TLS, FAQ: Frequently Asked Questions, http://tlsoakland.com/faq/.

- cartridge style, pulse-jet dust collectors or bin vents
- unloading boots, enclosed hopper and dust collection at the covered railcar dumper building
- enclosed storage domes with dust collection
- enclosed conveyor transfers
- covered conveyors
- dust collection at transfer point and shiploader (only "as required")
- dust collectors will include rotary air lock.

The design drawings indicate that the material handling equipment – storage domes and sheds, conveyors, loaders, etc. will not be located in an enclosed structure.[27] Thus, there will be emissions of PM, PM10, and PM2.5 from all of the above identified equipment.

ENVIRONMENTAL IMPACTS

The environmental impacts cannot be fully determined based on the available information, reviewed above. However, a similar proposal to export coal from the Port of Oakland was rejected by the Port of Oakland in connection with the proposed Howard Terminal. The issues identified by the Port of Oakland are outlined in a staff report that found significant environmental issues associated with handling export coal.[28] These impacts included:

At the Terminal:

- Fugitive coal dust and local air quality, requiring storage domes; enclosed conveyors and ship-loader systems;
- Risk of explosions;
- Impact of train length, up to 1.5 miles, on rail crossing in densely populated areas along route;
- Berth dredging to accommodate larger and more heavily laden vessels;
- Visual impacts of storage domes and other structures;
- Noise and vibrations from loading, unloading, and conveyor system;
- Construction impacts;
- Diesel particulate matter from train and ship engines;
- Greenhouse Gas (GHG) emissions from shipping coal from Utah to Oakland and Oakland to Asia.

[27] Conceptual Drawings, http://tlsoakland.com/pdf/19.pdf.

[28] Port of Oakland Memo from Anne Whittington to Richard Sinkoff, Re: Environmental Issues Associated with Handling Export Coal, February 19, 2014.

Transport from Mine Source to Terminal:

- The loss of up 12 tons of coal dust, assuming control using surfactants;
- Impacts of train lengths of up to 1.5 miles on rail crossing and noise from train safety horns and rail crossing barriers in communities along the rail line (Completely covering the rail cars could eliminate the dust.)

Coal Consumption in Asia:

- Inconsistent with California climate change policy
- Inconsistent with California Joint Resolution 35, Chapter 139[29]
- Inconsistent with goal to promote cleaner domestic energy source
- Potential to increase acid rain and mercury deposition in the Pacific Ocean and Western U.S. from Asia due to wind patterns

All of these issues apply to the current proposal with the possible exception of the need to dredge. In addition, the proposed Terminal presents the following additional issues not addressed in the Howard Terminal analysis:

- Water use for dust control
- Seismic-induced liquefaction and lateral spreading hazards due to site-specific soil conditions
- Impacts of coal spills on California's water supply
- Covered rail car issues
- Ignitability and spontaneous combustion
- Visual impacts of huge storage domes
- Impact of increase in rail and ship traffic on other operators within the Port of Oakland and elsewhere in San Francisco Bay

Some of these issues are discussed below.

Water Use

The major coal handling operations at the Terminal are enclosed. However, water is still required to control dust during unloading,[30] at storage piles within enclosures, at drop points, and during ship loading. Based on experience at other terminals, about 8 gallons of water are required per ton of coal throughput to control dust.[31] Assuming 100% of the Terminal's design throughput of 9.9 million tons per year is coal or another similarly dusty material, 79.2 million

[29] California Legislative Information, Assembly Joint Resolution No. 35, Chapter 139, Relative to Exportation of Coal, Approved by Governor, September 18, 2012, Filed with Secretary of State, September 18, 2012.

[30] See the significant amount of water used for coal unloading in the video, Unloading Coal via Rotary Dump, proposed for the Terminal, at: http://www.coalcap.com/press.asp.

[31] George D. Emmitt, Minimizing Groundwater Consumption for Required Fugitive Dust Control Programs, http://www.powerpastcoal.org/wp-content/uploads/2011/08/MINIMIZING-GROUNDWATER-CONSUMPTION-FOR-REQUIRED-FUGITIVE-DUST-CONTROL-PROGRAMS.pdf.

gallons of water would be required every year to control dust. In comparison, per capita water use in the area where the Terminal will be located is 71.7 gallons per person per day.[32] Thus, the water required to control dust at the proposed Terminal could supply over 3,000 Oakland residents every year.

California is currently experiencing a record-setting drought that started in 2012 and recently culminated in the first ever mandatory state-wide water restrictions. The April 2015 snow water equivalent was at only 5% of its historical average.[33] The snowpack is the major source of California's water supply, filling its reservoirs as temperatures warm and the snow melts. The record low snowpack coincides with record high January to March temperatures, highlighting the modulating role of temperature extremes in California drought severity. These results foreshadow major future impacts of climate change on the state's water supply. Further, the export of this coal will contribute to global warming and thus aggravate California's water supply situation. Therefore, the use of the state's severely depleted water supply, which is likely to remain so in the future, at a coal terminal that will aggravate the water supply deficit and contribute to global warming, is not a reasonable beneficial use of the State's limited water supply.

Wastewater Disposal

The 79.2 million gallons of water used each year to control dust will be highly contaminated with coal particles and other materials. The documents that I have reviewed identify only "process water collection and treatment facilities" but don't disclose whether "process water" is dust control wastewater nor what type of treatment would be used.[34] Conceptual drawing GC-100 identifies a "washdown treatment vault" with discharge to the Bay. These terms, "process water" and "washdown water", are ambiguous and have no special meaning. If the dust control wastewater is discharged into the Bay, it would result in significant biological impacts due to high amounts of suspended coal particles.

Accidents

The trains carrying Utah coal to the Terminal would most likely enter California in the northern part of the State, traveling via the Feather River Canyon or Donner Pass to the Bay

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[32] SWRCB, July 2015 Water Conservation Report by Supplier, Excel Spreadsheet: October 2014 – April 2015 Urban Water Supplier Report, http://www.waterboards.ca.gov/water_issues/programs/conservation_portal/conservation_reporting.shtml.

[33] S. Belmecheri et al., Multi-century Evaluation of Sierra Nevada Snowpack, Correspondence, Nature Climate Change, Advance Online Publication, September 14, 2015, http://www.nature.com/articles/nclimate2809.epdf?referrer_access_token=O7tjNvIGP2FXqNF-SJoocdRgN0jAjWel9jnR3ZoTv0MaTV2Rp6vP_EsijdwLJ1-6EMR-RFne5yHuc6YcKNVdCtzoyQ7rj7-QHAuGoydFDdl1GZvEKF_67xl1s32_i8IPfhF0DEEuVeX5gAS68cB5EzrRSO82GCWkqLz34Tmpso7K6rK_mAzmIsrJg7fm6zadxUJGEjxWuUWxeWbRCNrCqvXZGoKMz5WRE6T8-shfV6Iw2TQViyHAL47SGFeDXq6ddrl1KKQLA8Ohmsd4Z95MNwb4qEhsDB903Y4RdbzuGEulOtUpQO0HL41qQaVQp70IzN0AWUuIa5VJDXrPna5LIUUyusya39rwBp72lNCk__zfHqyaN14_6HG4oPUnFZKu&tracking_referrer=www.nytimes.com.

[34] 7/16/15 BOD, p. 4.

Area.[35] Thus, they will travel through some of the state's most densely populated areas, as well as some of its most sensitive ecological areas, as rail lines frequently operate near or over rivers and other sensitive waterways in the state.

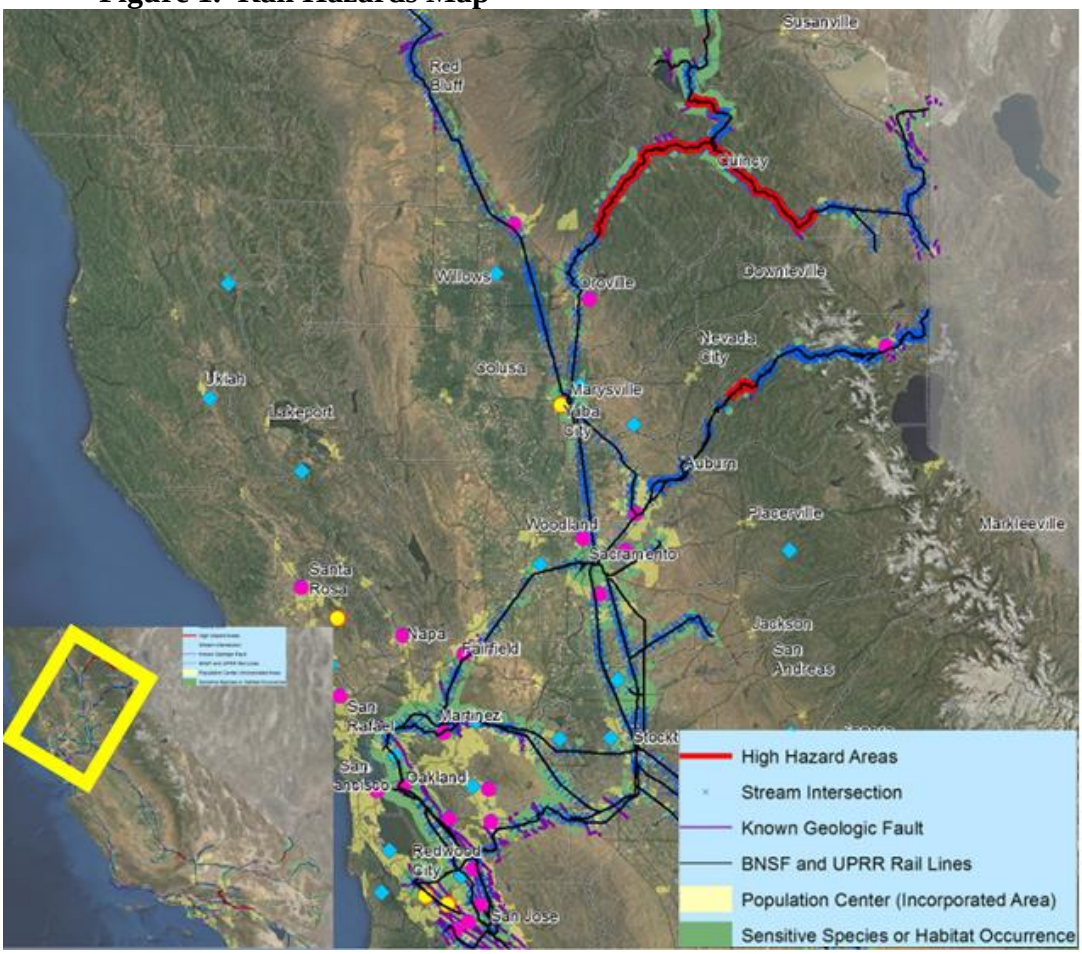
The two most likely routes include numerous "high hazard areas" where accidents are likely due to poor track and infrastructure conditions, e.g., steep grades, poor track condition, bridges in poor condition.[36] See red segments on Figure 1. An accident in these areas could result in a major release of coal into the State's water supply, which would be very difficult to cleanup due to the nature of coal. This could shut down the water supply for much of the state, resulting in significant statewide impacts on agricultural and municipal water supplies as well as significant aquatic biological impacts. A recent derailment in this area, involving corn, rang alarm bells as to the consequences if a more hazardous substance, such as coal, were involved.[37]

[35] See map of U.S. Major Freight Rail Lines at: http://earthjustice.org/features/map-crude-by-rail?utm_source=crm&utm_content=image&curation=ebrief. See also: Cambridge Systematics, Inc., National Rail Freight Infrastructure Capacity and Investment Study, September 2007, Figure 4.1, http://www.camsys.com/pubs/AAR_Nat_%20Rail_Cap_Study.pdf.

[36] Interagency Rail Safety Working Group, State of California, Oil by Rail Safety in California. Preliminary Findings and Recommendations, June 10, 2014.

[37] Tony Bizjak, Feather River Train Derailment Raises New Concerns, Sacramento Bee, December 6, 2014, http://www.sacbee.com/news/local/transportation/article4315150.html. See also: http://www.abc10.com/story/news/local/california/2014/11/26/train-derailment-feather-river-canyon/70133634/.

Figure 1. Rail Hazards Map



Further, the coal trains themselves could increase the probability of an accident by increasing the load on the tracks and by depositing coal dust on the tracks and in the track ballast, which are well known causes of train accidents. Coal trains weigh much more than other types of trains travelling these routes. The unit trains proposed to call at the Terminal loaded with coal, for example, weigh 15,600 tons[38] compared to 5,000 tons per train for double stack container trains, 8,500 tons for manifest trains, and 10,000 tons for grain trains.[39] The extra weight from these coal-carrying trains would pose additional stresses on the tracks, increasing the probability of accidents.

Further, unit trains have recently started importing crude oil to Bay Area refineries, using these same routes. A significant future increase in these crude trains is anticipated. The cumulative increase in unit crude oil and coal trains is a potentially deadly combination,

[38] Weight of 104 car unit train carrying coal: (104 cars)(130 tonne/car)(1.1 ton/tonne) + (5 locomotives)(150 ton/locomotive) = **15,622 tons.**

[39] Railway Capacity Background & Overview, http://www.quorumcorp.net/Downloads/Papers/RailwayCapacityOverview.pdf.

increasing derailment risk for both coal and oil trains.[40] Oil train derailments can decimate entire communities. The blast zones—within one mile of the rail tracks—for oil trains disproportionately impact environmental justice neighborhoods, communities with racial minorities, low incomes, or non-English speaking households.[41]

Coal Dust

Coal dust from both trains and the Terminal is notoriously difficult to control and results in numerous significant environmental impacts. The 7/16/15 BOD asserts that product will arrive at the Terminal in "North American Covered Hopper Cars", equipped with removable, fiberglass covers,[42] suggesting coal dust from the unit trains will be controlled. However, there is no enforceable condition to require that the rail cars be covered and shippers have historically resisted covering due to cost. The City and other permit-issuing agencies, such as the Bay Area Air Quality Management District, are likely preempted by federal law from regulating coal cars along the rail lines,[43] outside of the Terminal. Thus, the Terminal operator and the shippers can import coal in uncovered cars, regardless of assertions in the 7/16/15 BOD or elsewhere. The most recent Sept. 2015 HDR report prepared for California Capital Investment Group also analyzes uncovered coal cars.

Transporting coal in uncovered cars is standard industry practice to cut costs. Thus, most coal cars are uncovered. Covered rail cars have historically been used to transport bulk commodities such as grain, cement, fertilizers, food and sand, but not coal. While many companies are working on cover designs for coal cars, my research to date has not identified a commercial source for covered coal rail cars. Several companies have developed prototypes, but none are in commercial production. As there are no enforceable conditions requiring that the cars be covered, the applicant and Terminal users have no obligation to use covered rail cars. Thus, it is reasonable to assume that the rail cars servicing the Terminal will be uncovered. Therefore, I discuss some of the issues that will arise if the cars are not covered followed by a discussion of issues with covered cars, should they be used.

Coal dust can result in significant environmental impacts for two principal reasons. First, in California (and many other states), the rail lines parallel waterways. As shown in Figure 1, the two most likely rail routes to Oakland follow rivers and pass through the Sacramento-San Joaquin Delta, the largest and most biologically important estuary on the Pacific coast. These waterways also supply a significant fraction of California's water supply. Coal dust falling

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[40] *See e.g.*, Daily Oil Trains Could Threaten Lives in the Bay Area, SF Chronicle, August 10, 2015, http://blog.sfgate.com/hottopics/2015/08/10/daily-oil-trains-could-threaten-lives-in-the-bay-area/.

[41] Crude Injustice on the Rails, Communities for a Better Environment, June 30, 2015, http://www.cbecal.org/media/cbe-updates/crude-injustice-on-the-rails-report-calls-out-environmental-racism/.

[42] 7/16/15 BOD, Table 9-1.

[43] Tovah R. Trimming, Derailing Powder River Basin Coal Exports: Legal Mechanisms to Regulate Fugitive Coal Dust from Rail Transportation, Golden Gate University Environmental Law Journal, v. 6, issue 2, June 21, 2013, http://digitalcommons.law.ggu.edu/cgi/viewcontent.cgi?article=1104&context=gguelj. *See also* memo to CCIG from Venable, LLP, September 8, 2015 (arguing City of Oakland cannot regulate rail.)

along the tracks in these areas would be blown into or washed into the waterways by rainfall runoff. Second, there is a long history of coal dust creating nuisance conditions for those living and working adjacent to the tracks.

Uncovered Rail Cars

Uncovered rail cars carrying coal emit significant amounts of coal dust.[44] Most coal dust is emitted from the top of the rail car, but some is also emitted from the bottom. The movement of cars during transit creates vibrations that break larger pieces of coal into smaller particles, creating a continuous source of dust as the trains travel to their destination. Dusting also occurs on the empty return trip as leftover coal particles are blown out of the cars. This dust would be deposited along and adjacent to the rail lines between Utah and the Terminal as well as at the Terminal while waiting to be unloaded. Coal dust losses vary with wind speed, train speed, time of year, load shape, and topping agents.

While the 7/16/15 BOD asserts that covered rail cars will be used, this claim is unenforceable, the applicant has failed to identify a source of coal car covers, and there is no history of their use for transporting coal due to added cost and safety issues, discussed elsewhere. The September 2015 HDR report asserts that coal dust can be reduced by at least 85% using topping agents (surfactants) and load profiling/packing. However, these have not been proposed by the applicant and are also unenforceable.

A representative of BNSF testified before the Rail Energy Transportation Advisory Committee (RETAC) that coal loss from an uncovered bottom unloading car during a typical 400 mile trip is on average 45 lb from the bottom and 600 lb from the top, for a total of 645 lb per car.[45] Elsewhere, BNSF has reported that "The amount of coal dust that escapes from PRB coal trains is surprisingly large…BNSF has done studies indicating that from 500 lbs to a ton of coal can escape from a single loaded coal car. Other reports have indicated that as much as 3% of the coal loaded into a coal car can be lost in transit." BNSF has pulled this information from its website, but it was captured and duplicated elsewhere.[46] Norfolk Southern reported similar losses, up to 1,200 lb/car and typically 400 to 800 lb/car along a 500 mile rail corridor hauling a bituminous coals similar to the Utah coals.[47]

The rail distance from central Utah where the coal would be mined to the Terminal is about 750 miles. Assuming three 104-car unit trains per day, up to 68,300 tons/yr of coal dust

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[44] See dust from typical coal unit train at: https://www.youtube.com/watch?v=RzD2olpaooQ.

[45] Minutes, Rail Energy Transportation Advisory Committee, September 10, 2009, http://www.scribd.com/doc/129350651/Surface-TransMinutes-9-10-09-1.

[46] Cassandra Profita, How Much Coal Dust Will There Really Be?, July 30, 2012, http://www.opb.org/news/blog/ecotrope/10753/.

[47] Edward M. Calvin, G.D. Emmitt, and Jerome E. Williams, A Rail Emission Study: Fugitive Coal Dust Assessment and Mitigation, http://www.powerpastcoal.org/wp-content/uploads/2011/08/A-RAIL-EMISSION-STUDY-FUGITIVE-COAL-DUST-ASSESSMENT-AND-MITIGATION.pdf.

could be emitted from trains servicing the Terminal.[48] Assuming entry at Donner Pass, the shortest route, at least 200 miles of this route are in California. Thus, about 27% of the coal dust or about 18,200 tons/yr could be released within the state. While much of this dust would be deposited near the tracks, which are adjacent to rivers and estuaries, a significant amount of the coal dust would become air borne and cause significant downwind air quality, public health, and ecosystem impacts.[49]

Some have claimed—including the recent Sept. 2015 HDR report submitted by CCIG at p. 5—that most of this coal dust is deposited close to the mine. However, numerous You Tube and other videos[50] and Seattle Times photos in the Columbia River Gorge debunk this claim. See Figure 2. Dust is generated throughout the trip by movement of the cars during transit, particularly over the mountainous terrain between the mines in central Utah and Oakland, e.g., they must cross the Sierra Nevada mountains, which will require numerous speed changes as the trains negotiate challenging mountain passes, steep grades, and sharp curves. The references to behavior of wind blown dust from stationary storage piles in the Sept. 2015 HDR report at 5 are irrelevant to train travel. The problems caused by released coal dust are detailed below.

Figure 2. Photograph of Unit Coal Train Passing Through Columbia River Gorge.

First, railroads in California (and elsewhere, see Figure 2) parallel or cross many rivers and estuaries (Figure 1), which contain sensitive species and are lined with riparian corridors.

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[48] Coal dust: Assuming 645 lb/car x (750 mi/400 mi) x 104 cars/train x 3 trains/day x 362 day/yr/2000 lb/ton = **68,296 lbs**.

[49] See reviews in: Dan Ferber, Research Finds Additional Harm from Coal Dust Exposure, February 20, 2013, http://midwestenergynews.com/2013/02/20/research-finds-additional-harm-from-coal-dust-exposure/ and Eric de Place, How Coal Affects Water Quality: State of the Science, March 20, 2013, http://daily.sightline.org/2013/03/20/how-unburnt-coal-affects-water-the-state-of-the-science/.

[50] See the videos at Coal Dust: Norfolk Southern's Most Insidious Gift to Its Own Hometown, http://coaldustnorfolk.com/NSCoalHandling.html.

Thus, some of the 68,300 tons/yr of coal dust released during transit from Utah could end up in riparian zones and waterways, resulting in significant ecological impacts.

Coal dust that reaches waters adjacent to rail lines – such as the American, Feather, Yuba, and Sacramento Rivers and the Sacramento-San Joaquin Delta -- will have adverse physical effects on exposed organisms including abrasion, smothering, reduction in availability of light and clogging of respiratory and feeding organs.[51] Young salmon and trout exposed to coal washings, for example, experienced 100% mortality after 0.5 to 2.5 hrs exposure. The dead fish had heavy secretions of mucus from the skin and gills, to which particles of coal adhered.[52] In another study, exposure of juvenile chinook salmon to coal dust resulted in metabolic activation of genes that convert PAHs to carcinogenic and mutagenic metabolites. Coal dust leachates also reduce the growth rate of trout, cause oocyte atresia and reduce ovarian growth in crayfish, and promote DNA adduct formation and hepatocellular carcinoma in fish.[53]

Second, coal dust destabilizes rail bed ballast, which underlies and stabilizes tracks and has led to accidents, high cleanup costs, and litigation to require shippers of coal from the Powder River Basin to use surfactants to reduce coal dust. BNSF spent more than $100 million cleaning and replacing track ballast in Wyoming in 2009 and 2010. These surfactant rules do not apply to coal shipped from Utah. Further, the dust also deposits on the tracks, causing derailments.[54]

Third, coal dust, blown from unit trains, the Terminal, and staged rail cars at the Terminal, can have many impacts on humans, animals, and plants along the rail lines and in adjacent communities. The coal dust blown or otherwise emitted from these sources consists mainly of fine black particles that are carried by winds onto properties adjoining the Terminal and rail tracks. The most intense dusting events occur when trains travelling in opposite directions meet at normal track speeds,[55] which will be common occurrences due to operation of the Terminal. In addition, tunnels, trestles, and open field often cause emissions due to lateral wind stresses.[56]

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[51] Michael J. Ahrens and Donald J. Morrisey, Biological Effects of Unburnt Coal in the Marine Environment, Oceanography and Marine Biology: An Annual Review, v. 43, pp. 69-122, 2005.

[52] C.F. Pautzke, Studies on the Effect of Coal Washings on Steelhead and Cutthroat Trout, Transactions of the American Fisheries Society, v. 67, pp. 232-233, 1937.

[53] P.M. Campbell and R.H. Devlin, Increased CYP1A1 and Ribosomal Protein L5 Gene Expression in a Teleost: The Response of Juvenile Chinook Salmon to Coal Dust Exposure, Aquatic Toxicology, v. 38, pp. 1-15, 1997.

[54] See, for example:
http://www.stb.dot.gov/decisions/readingroom.nsf/fc695db5bc7ebe2c852572b80040c45f/3bdd891ff0ccc1fb8525794f006db7c9?OpenDocument
and http://www.stb.dot.gov/decisions/ReadingRoom.nsf/WEBUNID/79B5382AE20F7930852578480053111F?OpenDocument.

[55] Simpson Weather Associates, Inc., Norfolk Southern Rail Emission Study, December 30, 1993, http://leg2.state.va.us/dls/h&sdocs.nsf/By+Year/SD581994/$file/SD58_1994.pdf. See also video at: https://www.youtube.com/watch?v=qVUJcmxZ7BE.

[56] Report of the Joint Subcommittee Studying Ways to Reduce Emissions from Coal-Carrying Railroad Cars, Senate Document No. 23, Commonwealth of Virginia, 1997.

Farmers, landowners, and communities along the rail lines would have to deal with nuisance black grit covering their crops, lawns, homes, vehicles, and more seriously, increasing particulate matter in the ambient air, which would result in significant public health issues.[57] See coal dust videos.[58] Testimony before the Joint Subcommittee Studying Ways to Reduce Emissions from Coal-Carrying Railroad Cars" was summarized as follows:[59]

> "Homes and cars need repeated washing, windows and doors must stay closed and outdoor activity is curtailed because of the coal dust. Patio furniture and gardens are said to glisten with coal dust.
>
> A so-called "blowout," typically occurring during extreme meteorological conditions, can result in 40-foot-high clouds of dust billowing upward. Particularly bad episodes have reportedly forced some vehicles traveling along Route 29 to turn on headlights or pull off of the road. Homeowners have made claims with NS in exceptional cases to pay for the cleaning of their homes…[high winds are common in the Bay Area].
>
> For those so affected, the constant presence of coal dust was characterized as a burden that diminishes their quality of life. The dust leaves a greasy black film wherever it lands, settling on windowsills and finding its way through cracks and crevices. Although documentation has not been available, some citizens exposed to emissions expressed concerns about the potentially harmful health effects of coal dust exposure."

Similar complaints have been reported by communities in the Bay Area from coal trains that currently pass through Richmond on their way to the Levin Terminal. "In Parchester Village, a largely black and Latino neighborhood in northwestern Richmond, residents say coal dust blows off the open mounds, covering the grass and coating their screen doors…It's everywhere, he says. If your truck sits here for two, three days without moving you can write your name on the front."[60]

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http://leg2.state.va.us/dls/h&sdocs.nsf/fc86c2b17a1cf388852570f9006f1299/0bef1dac9cc18b48852564420068dc18/$FILE/SD23_1997.pdf.

[57] Paul R. Epstein and others, Full Cost Accounting for the Life Cycle of Coal, Annals of the New York Academy of Sciences, v. 1219, 2011, p. 84.

[58] See videos at: https://www.youtube.com/watch?v=o4v5w-TuhWM; https://www.youtube.com/watch?v=6WdsrkyaGZI; https://www.youtube.com/watch?v=tFlXHT6KCRM; https://www.youtube.com/watch?v=gjhnhZ0mFb4; https://www.youtube.com/watch?v=LwuBhcffcoo.

[59] Report of the Joint Subcommittee Studying Ways to Reduce Emissions from Coal-Carrying Railroad Cars, to the Governor and the General Assembly of Virginia, Senate Document No. 58, Commonwealth of Virginia, Richmond, 1995, http://leg2.state.va.us/dls/h&sdocs.nsf/By+Year/SD581994/$file/SD58_1994.pdf.

[60] Julie Small, Coal Train Dust Worries Richmond Residents, KQED, June 22, 2015, http://ww2.kqed.org/science/2015/06/22/coal-train-dust-worries-richmond-residents/.

"Coal dust" is an umbrella term that includes the full range of particle classifications based on size, from granules to very small particles. Known health effects from coal dust exposure include skin damage, circulatory system problems, and increased risk of developing cancer. In one study, coal dust was associated with respiratory morbidity in school children. A cross section study found that respiratory symptoms were significantly more common in children in the areas exposed to coal dust than the control areas. Elevated symptoms included wheezing, excess cough, and school absences for respiratory symptoms.[61] In another study, proximity to coal mining activities was associated with worse adjusted health status and with higher rates of cardiopulmonary disease, chronic obstructive pulmonary disease, hypertension, lung disease and kidney disease.[62]

Coal dust includes fine particles, both PM10 and PM2.5.[63] These would be emitted from the coal trains along their entire route, from Utah to the Terminal in Oakland as well as from the Terminal itself. Coal dust would be released from staged rail cars waiting to be unloaded,[64] rail car unloading, coal conveying, blending, storing, and transferring coal to ships.

These pollutants are directly linked to health problems because they can travel deep into the lungs, some reaching the bloodstream. They thus affect both the lungs and heart. Numerous scientific studies have linked particle pollution to a variety of health problems, including premature death in people with pre-existing lung and heart disease, nonfatal heart attacks, irregular heartbeat, aggravated asthma, decreased lung function, and increased respiratory symptoms, such as irritation of airways, coughing, or difficulty breathing.[65] The Utah coals that will be imported have elevated levels of silica,[66] which is more toxic than coal and is regulated to 1/20th the level of coal dust in occupational settings. Exposure to coal dust with elevated silica can result in silicosis, pulmonary tuberculosis, and lung cancer.[67]

Coal dust from uncovered rail cars also can result in other impacts, including soil contamination, visibility impairment, environmental damage, and aesthetic damage. A study adjacent to a coal terminal in Norfolk, Virginia found elevated arsenic associated with coal

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[61] Bernard Brabin and others, Respiratory Morbidity in Merseyside Schoolchildren Exposed to Coal Dust and Air Pollution, Archives of Disease in Childhood, v. 70, pp. 305-312, 1994.

[62] M. Hendryx and M.M. Ahern, Relations Between Health Indicators and Residential Proximity to Coal Mining in West Virginia, American Journal of Public Health, v. 98, pp. 669-671, 2008.

[63] Daniel Jaffe and others, Diesel Particulate Matter and Coal Dust from Trains in the Columbia River Gorge, Washington State, USA, Accepted for publication in Atmospheric Pollution Research, April 23, 2015.

[64] Phyllis Fox, Fugitive Particulate Matter Emissions from Coal Train Staging at the Proposed Coyote Island Terminal, Final Report Prepared for Sierra Club, July 19, 2013.

[65] U. S. Environmental Protection Agency. Particulate Matter, Health, http://www.epa.gov/pm/health.html.

[66] Silica levels range from 58.4% to 61.4% at four Bowie mines that may supply the Terminal. Sept. 2015 HDR Report, p. 13, http://bowieresources.com/skyline/.

[67] Jay Colinet, Health Effects of Overexposure to Respirable Silica Dust, Silica Dust Control Workshop, September 28, 201, http://www.cdc.gov/niosh/mining/UserFiles/workshops/silicaMNM2010/1-Colinet-HealthEffects.pdf.

particles, 2 to 20 times higher than upper crustal levels and 5 times higher than background soil.[68]

The Sept. 2015 HDR report at 14 argues that trace metals in Utah coal are not a concern. However, they base their argument on EPA residential soil screening levels, rather than California risk-based screening levels.[69] The California levels indicate that arsenic levels in Utah coal (1 – 8 mg/kg) are 14 to 114 times higher than the residential soil-screening level (0.07 mg/kg) and are also significantly higher than the commercial/industrial level (0.24 mg/kg).

Coal particles can be carried long distances, settling in lakes and streams, where they can increase acidity and change nutrient balances; deplete soil nutrients; damage sensitive forests and farm crops; and affect the diversity of ecosystems. A study in Oregon, for example, correlated coal dust deposition with significantly higher soil temperatures, decreased soil pH, increased moisture-holding properties, and elevated heavy metal concentrations. These changes were possibly responsible for the lower frequencies and diversity of lichen species in the impacted area.[70] Others have noted that coal dust significantly reduced carbon dioxide exchange of upper and lower leaf surfaces.

The Sept. 2015 HDR study at 13-15 attempts to set aside any worry about coal dust emissions from coal transport as "operations at OBOT will require an air permit through BAAQMD, one of the most stringent regulatory agencies in the U.S…." However, this is incorrect. The BAAQMD has no jurisdiction over emissions from rail transport or mobile sources in general. None of the permits required for the Terminal will limit coal dust emissions from trains. This is an unregulated source.

Covered Rail Cars

While covered rail cars sound like a good idea as they would prevent the release of coal dust, they pose a different set of issues. First, who would own or lease them, the railroads, the coal producers, or the company importing coal from abroad? The Terminal would have no control over whether the trains arrive covered or uncovered. Thus, the claim in the 7/16/15 BOD that the rail cars will be equipped with "removable, fiberglass covers"[71] is meaningless. Further, while the proposed covers could control the dust from the top of the train, they would not control dust from the bottom of the train, which comprises 7% of the total. Further, covered coal cars would create other issues.

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[68] William J. Bounds and Karen H. Johanneson, Arsenic Addition to Soils from Airborne Coal Dust Originating at a Major Coal Shipping Terminal, Water Air Soil Pollution, 185:195-207, 2007.

[69] Office of Environmental Health Hazard Assessment and California Environmental Protection Agency, Human-Exposure-Based Screening Numbers Developed to Aid Estimation of Cleanup Costs for Contaminated Soil, January 2005, Table 5, http://www.oehha.ca.gov/risk/pdf/screenreport010405.pdf.

[70] Sherry Spencer, Effects of coal dust on species composition of mosses and lichens in an arid environment. Journal of Arid Environments, v. 49, issue 4, pp. 843-853, 2001. Abstract available at: http://www.sciencedirect.com/science/article/pii/S014019630190816X.

[71] 7/16/15 BOD, Table 9-1.

First, coal is a highly combustible material, characterized in the 7/16/15 BOD as "very dusty, exhibits spontaneous combustion behavior, potentially explosive."[72] Containing this material in a limited space, beneath a cover, could facilitate spontaneous combustion, by trapping heat in the car. This could result in the delivery of rail cars at the Terminal partially on fire and emitting toxic gases.[73] In fact, it is well known that covered cars that are not properly ventilated are a safety hazard because they increase the risk of the coal spontaneously combusting.[74] Ventilated tops would reduce this risk, but shippers claim they are too expensive. Further, ventilated tops would allow the emission of some coal dust.

The proposal here is for unventilated fiberglass covers, which, if used, present significant safety and public health issues for those along the rail route and near the Terminal in West Oakland. Smoldering rail cars moving through the densely populated Bay Area and queued up at the Terminal present a significant public health risk to nearby businesses and residents as they would release toxic air pollutants.

Second, fiberglass covers can break, bend, blow off, and fall off. Given that train lines pass through residential and commercial areas, such as Fourth Street in Berkeley, these covers could cause serious damage to adjacent properties, pedestrians, and motor vehicles.[75]

Traffic Impacts at Train Crossings

Unit coal trains will adversely impact traffic at at-grade rail crossings, or places where the railroad tracks cross a road.[76] There are 55 at-grade rail crossings between Benicia and the proposed Terminal. A 104-car unit train is about 1.3 miles long[77] and would travel at a rate of about 10 mi/hr in urban areas. Thus, it would take a unit train 9 minutes[78] to pass any given point. Further, a 1.3 mile long train would block multiple rail crossings simultaneously. This would occur up to six times per day for 362 days out of each year as two to three unit trains filled with coal and two to three empty unit trains would pass through each of these crossings. Thus, each crossing would be blocked for up to an hour, 362 days of the year.

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[72] 7/16/15 BOD, Table 5-1.

[73] Coal's Spontaneous Combustion Problem, Sightline Daily, April 11, 2012, http://daily.sightline.org/2012/04/11/coals-spontaneous-combustion-problem/.

[74] Nick Gier, Coal Trains Threaten Environment and Public Health, http://www.sustainablepalouse.org/docs/CoalTrains2923.pdf.

[75] See, for example, Metal Covers Blow off Freight Train, Lompoc Record, July 2, 2006, http://lompocrecord.com/news/local/metal-covers-blown-off-freight-train/article_3ddb578f-5262-595f-8dd5-f439e36d61ef.html.

[76] See, for example, "The bane of all drivers in Seattle's SODO neighborhood: train crossings", http://www.seattlepi.com/local/transportation/article/Getting-There-How-long-can-trains-legally-block-1403713.php.

[77] The proposed trains would have 104 cars. This would require up to 5 locomotives. A locomotive is about 80 ft long and a typical hopper car about 60 ft long. Thus, a 104-car unit train would be: (5x80) + (104x60) = 6,640 ft or about 1.3 miles long, ignoring the gaps between cars.

[78] Transit time = 1.3 miles/10 mi/hr x 60 min/hr + 1 min (open and close gates) = 8.8 minutes.

This long transit time blocking numerous sequential rail crossings simultaneously would create significant traffic jams during rush hours. It would also delay emergency medical response times, significantly impeding emergency vehicles, such as ambulances and fire trucks, creating public emergencies. Finally, it would increase the probability of train-vehicle collisions at grade crossings.

Air Emissions

The unit trains carrying coal to the Terminal will be powered by up to five diesel-fueled locomotives that emit diesel particulate matter (DPM) as well as criteria air pollutants (NOx, SO2, PM10, PM2.5, CO) along rail lines and while idling at the Terminal.[79] Further, ships and supporting tugs that export the coal, and diesel-fired equipment within the Terminal all emit DPM as well as criteria air pollutants. As coal trains weigh much more than other types of trains carrying different products, emissions from exporting coal would be proportionally higher from coal trains than from other types of trains because more locomotives would be needed to carry the extra weight. As noted elsewhere in this report, the unit trains proposed to call at the Terminal loaded with coal weigh much more than other types of trains using these rail lines.

Increased emissions of diesel particulate matter would likely result in significant health impacts in exposed populations along the rail lines and in the vicinity of the Terminal. Exposure to DPM has been linked with acute short-term symptoms such as headache, dizziness, light-headedness, nausea, coughing, difficult or labored breathing, tightness of chest, and irritation of the eyes, nose and throat. Long-term exposures can result in cardiovascular disease, cardiopulmonary disease, increased probability of heart attacks, lung cancer, worsening of asthma, and infant mortality. Children, teens and the elderly are especially vulnerable.[80]

Health risk assessments of rail terminals and ports have found significant cancer risks from DPM up to 2 miles from the facilities. A health risk assessment prepared by the Spokane Regional Clean Air Agency found significant cancer risk (>10 cases in one million exposed) from DPM up to 2 miles from the BNSF Railyard.[81] A health risk assessment of the BNSF Stockton Railyard reported cancer risks from DPM at 100 in a million within 300 yards of the railyard, at 50 in a million within one half mile, at 25 to 50 in a million within 1 mile, and at 10 in a million at up to 2 miles from the railyard.[82] Similar cancer risk levels have been reported at railyards and terminals throughout the state[83] and would be expected in the vicinity of the Terminal, resulting in significant cancer risks in West Oakland.

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[79] Jaffe et al. 2015; Daniel A. Jaffe et al., Diesel Particulate Matter Emission Factors and Air Quality Implications from In-Service Rail in Washington State, USA, Atmospheric Pollution Research, v. 5, pp. 344-351, 2014.

[80] OEHHA, Health Effects of Diesel Exhaust, http://oehha.ca.gov/public_info/facts/pdf/diesel4-02.pdf.

[81] Spokane Regional Clean Air Agency, Health Risk Study for the Burlington Northern/Santa Fe Railroad Spokane Railyard, September 6, 2011, https://www.spokanecleanair.org/documents/air%20quality%20monitoring%20reports%20studies/BNSF%20Spokane%20Railyard%20Health%20Study.pdf.

[82] California Air Resources Board (CARB), Health Risk Assessment for BNSF Railway Stockton Railyard, November 19, 2007, http://www.arb.ca.gov/railyard/hra/bnsf_stockton_hra.pdf.

[83] See, e.g., Port of Long Beach Pier S Redevelopment Project (http://www.polb.com/civica/filebank/blobdload.asp?BlobID=8735); Port of Los Angeles San Pedro Waterfront

Noise

The equipment in the Terminal – ship loaders, switching locomotives, stackers, conveyors, reclaimers, railcar dumpers, ship loaders, dozers, etc. -- are major sources of noise that will be audible in adjacent West Oakland communities and will cause significant noise and vibration impacts.

Further, the unit trains that service the Terminal are major sources of noise that will adversely affect communities along the rail lines and adjacent to the Terminal. The noise from trains is legendary. In Berkeley where I live, train noise can be heard throughout the city, from Fourth Street near the tracks into the Berkeley Hills, 5 miles distant.

While there are many sources of noise from trains (high-pitch screeching, rumbling, idling engines, moving cars, etc.), horn sounding is the most significant. Federal rules governing the blowing of locomotive engine horns require that engineers of all trains sound horns for at least 15-20 seconds at 96-110 decibels (dB) at all public crossings. Decibels in the range of 80-105 are extremely loud, whereas those above 105 are dangerous. Decibels are logarithmic, meaning that 100 decibels is ten times as loud as 90, 110 decibels is ten times as loud as 100, and so on.

Trains servicing the Terminal will pass through 55 at-grade public crossings within the Bay Area. Round trip travel of up to three unit trains per day through 55 at-grade crossing will result in about 2 hours of horn noise[84]. Thus, every day that the Terminal operates, residents within communities along the rail line will be exposed to nearly 2 hours of extremely loud train horns.[85]

While impacts to quality of life from repeated loud noise are self-evident, chronic noise exposure has been proven to cause adverse health effects, including cardiovascular disease; cognitive impairment in children; sleep disturbance and resultant fatigue; hypertension; arrhythmia; increased rate of accidents and injuries; and exacerbation of mental health disorders such as depression, stress and anxiety, and psychosis.[86]

Secondary effects from sleep disturbance can also occur including fatigue, depressed mood and well-being, and decreased performance and alertness. Cardiovascular effects, independent of sleep disturbance, can also occur with acute exposure to noise mostly due to elevated blood pressures and levels of stress-induced hormones. In addition, noise can exacerbate

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Project (http://www.portoflosangeles.org/EIR/SPWaterfront/DEIR/AppxD3_HRA.pdf); Four Commerce Railyards (http://www.arb.ca.gov/railyard/hra/4com_hra.pdf); BNSF Watson (http://www.arb.ca.gov/railyard/hra/bnsf_watson_hra.pdf).

[84] Daily duration of train noise: 20-seconds/sounding x 55 at-grade crossings x 6 train trips/day = 6,600 seconds= 1.83 hours.

[85] http://www.coaltrainfacts.org/key-facts#trains.

[86] http://www.coaltrainfacts.org/key-facts#sthash.X5aI5sYT.dpuf.

stress and anxiety and impair task performance. The National Institute for Occupational Safety and Health recommends less than 15 minutes of exposure per day to noises over 100 dB.[87]

Visual Impacts

The Terminal, located at the foot of the new Bay Bridge and adjacent to communities in West Oakland, will not be fully enclosed based on currently available design drawings. Thus, the various components will be visible from West Oakland, local freeways, and the Bay Bridge. These components include the Commodity A storage buildings, enclosures that are about 100 feet high and 203 feet in diameter[88] and the Commodity B dome which is 142 feet high and 167 feet in diameter.[89] Also visible will be thousands of feet of conveyors and the ship loading apparatus. These massive structures will block views of the Bay and attract attention of passing motorists, which could potentially lead to accidents.

CONCLUSION

In summary, many adverse impacts would result if coal were imported at the proposed Terminal, rather than other materials. These include:

- High water usage to control Terminal dust, especially significant in light of the California drought and further anticipated impacts from climate change
- Adverse public health impacts from coal dust and diesel particulate matter emitted by unit coal trains and the facility,
- Increased potential of train accidents that could adversely impact the state's water supply,
- Adverse aquatic and riparian ecosystem impacts adjacent to the rail lines,
- Adverse noise and vibration impacts along the rail lines and in West Oakland near the Terminal, and
- Adverse traffic impacts, including delayed response time of emergency vehicles.

None of these impacts were anticipated in the CEQA review of this Project. Further, none of the mitigation measures listed in the Sept. 8, 2015 Stice & Block Letter address these impacts. None of these impacts would be mitigated by any of the permits that must be obtained to operate the Terminal.

[87] http://www.coaltrainfacts.org/key-facts#trains.

[88] Conceptual Drawing BMH-142.

[89] Conceptual Drawing BMH-150.

Carbon Dioxide Emission Factors for Coal

by

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Note: This article was originally published in Energy Information Administration, *Quarterly Coal Report, January-April 1994*, DOE/EIA-0121(94/Q1) (Washington, DC, August 1994), pp. 1-8.

Introduction

Coal is an important source of energy in the United States, and the Nation's reliance on this fossil fuel for electricity generation is growing. The combustion of coal, however, adds a significant amount of carbon dioxide to the atmosphere per unit of heat energy, more than does the combustion of other fossil fuels.(1) Because of a growing concern over the possible consequences of global warming, which may be caused in part by increases in atmospheric carbon dioxide (a major greenhouse gas), and also because of the need for accurate estimates of carbon dioxide emissions, the Energy Information Administration (EIA) has developed factors for estimating the amount of carbon dioxide emitted as a result of U.S. coal consumption.

Carbon dioxide emission factors for U.S. coals have previously been available from several sources. However, those emission factors have shortcomings because they are based on analyses of only a few coal samples. Most are single factors applied to all coals, regardless of rank (i.e., whether anthracite, bituminous, subbituminous, or lignite) or geographic origin. Because single factors do not account for differences among coals, they fail to reflect the changing "mix" of coal in U.S. coal consumption that has occurred in the past and will occur in the future. Lacking standardization, the factors previously available also differ widely from each other.(2)

EIA's emission factors will improve the accuracy of estimates of carbon dioxide emissions, especially at State and regional levels, because they reflect the difference in the ratio of carbon to heat content by rank of coal and State of origin. EIA's emission factors are derived from the EIA Coal Analysis File, a large database of coal sample analyses. The emission factors vary significantly by coal rank, confirming a long-recognized finding, and also within each rank by State of origin. These findings were verified statistically.

Two types of carbon dioxide emission factors have been developed. First are basic emission factors covering the various coal ranks by State of origin. These basic emission factors are considered as "fixed" for the foreseeable future until better data become available. Second are emission factors for use in estimating carbon dioxide emissions from coal consumption by State, with consuming-sector detail. These emission factors are based on the mix of coal consumed and the basic emission factors by coal rank and State of origin. These emission factors are subject to change over time, reflecting changes in the mix of coal consumed.

EIA's emission factors will not only enable coal-generated carbon dioxide emissions to be estimated more accurately than before, but they will also provide consistency in estimates. Energy and environmental analysts will find EIA's emission factors useful for analyzing and monitoring carbon dioxide emissions from coal combustion, whether they are estimated by the State of origin of the coal, consuming State, or consuming sector.

Coal Combustion and Carbon Dioxide Emissions

The amount of heat emitted during coal combustion depends largely on the amounts of carbon, hydrogen, and oxygen present in the coal and, to a lesser extent, on the sulfur content. Hence, the ratio of carbon to heat content depends on these heat-producing components of coal, and these components vary by coal rank.

Carbon, by far the major component of coal, is the principal source of heat, generating about 14,500 British thermal units (Btu) per pound. The typical carbon content for coal (dry basis) ranges from more than 60 percent for lignite to more than 80 percent for anthracite. Although hydrogen generates about 62,000 Btu per pound, it accounts for only 5 percent or less of coal and not all of this is available for heat because part of the hydrogen combines with oxygen to form water vapor. The higher the oxygen content of coal, the lower its heating value.(3) This inverse relationship occurs because oxygen in the coal is bound to the carbon and has, therefore, already partially oxidized the carbon, decreasing its ability to generate heat. The amount of heat contributed by the combustion of sulfur in coal is relatively small, because the heating value of sulfur is only about 4,000 Btu per pound, and the sulfur content of coal generally averages 1 to 2 percent by weight.(4) Consequently, variations in the ratios of carbon to heat content of coal are due primarily to variations in the hydrogen content.

The carbon dioxide emission factors in this article are expressed in terms of the energy content of coal as pounds of carbon dioxide per million Btu. Carbon dioxide (CO_2) forms during coal combustion when one atom of carbon (C) unites with two atoms of oxygen (O) from the air. Because the atomic weight of carbon is 12 and that of oxygen is 16, the atomic weight of carbon dioxide is 44. Based on that ratio, and assuming complete combustion, 1 pound of carbon combines with 2.667 pounds of oxygen to produce 3.667 pounds of

carbon dioxide. For example, coal with a carbon content of 78 percent and a heating value of 14,000 Btu per pound emits about 204.3 pounds of carbon dioxide per million Btu when completely burned.[5] Complete combustion of 1 short ton (2,000 pounds) of this coal will generate about 5,720 pounds (2.86 short tons) of carbon dioxide.

Methodology and Statistical Checks

EIA's carbon dioxide emission factors were derived from data in the EIA Coal Analysis File, one of the most comprehensive data sources on U.S. coal quality by coalbed and coal-producing county. Most of the samples in the file were taken from coal shipments to U.S. Government facilities, from tipples and from mines. From the more than 60,000 coal samples in the File, 5,426 were identified as containing data on heat value and the ultimate analysis[6] needed for developing the relationship between carbon and heat content of the coal, that is, the carbon dioxide emission factors. Coal rank was assigned to each sample according to the standard classification method developed by the American Society for Testing and Materials. These data observations (samples) covered all of the major and most of the minor coal-producing States (Table FE1). Except for Arizona, North Dakota, and Texas, all of the major coal-producing States were considered to have a sufficiently large number of data observations to yield reliable emission factors.

The ratio of carbon to heat content was computed for each of the 5,426 selected coal samples by coal rank and State of origin under the assumption that all of the carbon in the coal is converted to carbon dioxide during combustion.[7] Variations in the ratios were observed across both coal rank and State of origin. Analysis was performed to determine whether these variations were statistically significant and to ensure that other factors pertaining to the samples (that is, the year the sample was collected and the degree of cleaning the sample received) were not significantly responsible for the observed variations.

Table FE1. Number of Observations by Coal Rank and State of Origin

State of Origin	Anthracite	Bituminous	Sub-bituminous	Lignite
Alabama	--	224	--	--
Alaska	--	--	--	--
Arizona	--	8	--	--
Arkansas	--	8	--	--
California	--	--	--	--
Colorado	--	164	18	--
Georgia	--	1	--	--
Idaho	--	2	--	--
Illinois	--	332	--	--
Indiana	--	51	--	--
Iowa	--	67	1	--
Kansas	--	19	--	--
Kentucky: East	--	486	--	--
Kentucky: West	--	151	--	--
Louisiana	--	--	--	--
Maryland	--	13	--	--
Missouri	--	86	--	--
Montana	--	6	23	2
Nevada	--	4	--	--
New Mexico	--	50	--	--
North Dakota	--	--	--	16
Ohio	--	228	--	--
Oklahoma	--	155	--	--
Oregon	--	--	2	--
Pennsylvania	523	679	--	--
South Dakota	--	--	--	3
Tennessee	--	271	--	--
Texas	--	--	--	11
Utah	--	104	2	--
Virginia	--	169	--	--
Washington	--	181	36	4
West Virginia	--	1,071	--	--
Wyoming	--	133	121	1
Total.	**523**	**4,663**	**203**	**37**

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, "Analysis of the Relationship Between the Heat and Carbon Content of U.S. Coals," September 1992.

Distributions of the data observations by year of collection and degree of cleaning were compiled (Table FE2). Because the dates of the samples range from 1900 through 1986, it was thought that changes in laboratory analysis techniques over the years might have influenced the resultant carbon-to-heat-content ratios. A regression analysis found that, with a R^2 value of only 0.01 (Table FE3), the year the sample was collected was not a useful factor in explaining the variation in the ratio, although there were small changes in the ratio over time.[8] This finding indicated that samples from earlier time periods could be combined with more recent samples to derive carbon dioxide emission factors.

Table FE2. Distribution of Observations by Year and Degree of Cleaning

Year	Number of Observations	Percent of Total
1900-1909	217	4.0
1910-1919	679	12.5
1920-1929	657	12.1
1930-1939	772	14.2
1940-1949	744	13.7
1950-1959	1,043	19.2
1960-1969	557	10.3
1970-1979	339	6.2
1980-1986	418	7.7
Total	5,426	100.0
Degree of Cleaning		
Raw	4,519	83.3
Washed	847	15.6
Partially washed	60	1.1

Note: Total may not equal sum of components due to independent rounding.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, "Analysis of the Relationship Between the Heat and Carbon Content of U.S. Coals," September 1992.

Of the total samples, 83 percent were raw coal, with the remainder either washed or partially washed. Cleaning should not materially affect the ratio of a coal's heat-to-carbon content because the process removes primarily non-combustible impurities. This was confirmed by an analysis of variance. There were differences in the carbon-to-heat-content ratios between washed or partially washed and raw coal, but with a R^2 value of 0.06, the differences did little to explain the variation in the ratios. Therefore, no data correction was warranted to account for the small effect that coal cleaning had on emission factors.

Analysis of variance was used to test the statistical significance of differences in the carbon-to-heat-content ratios across coal rank and across State of origin within coal rank. The continuous response variable (the carbon dioxide emission factor) was related to classification variables of rank and State of origin. The carbon dioxide emission factor was assumed to be a linear function of the parameters associated with the coal rank and State of origin.[9]

The statistical analyses (Table FE3) indicated that: (1) there are statistically significant differences in carbon dioxide emission factors across both coal rank and State of origin; (2) coal rank and State of origin each explain approximately 80 percent of the variation in carbon dioxide emission factors; and (3) State of origin combined with coal rank is a slightly more powerful explanatory variable than either coal rank or State of origin alone.

Table FE3. Summary of Statistical Analyses Carbon Dioxide Emission Factors by Coal Rank and State of Origin

Variable	F Test	R^2	MSE	Root MSE
Year Collected	***	0.01	55.18	7.43
Degree of Cleaning	***	0.06	52.07	7.22
Coal Rank	***	0.78	12.24	3.50
State of Origin	***	0.81	10.78	3.28
State of Origin Combined				
with Coal Rank	***	0.82	9.98	3.16

Notes: The F test indicates the statistical significance of differences in the emission factors across levels of the explanatory variable; *** indicates significance at the 0.001 level. R^2 (coefficient of determination) indicates the proportion of total variation in the emission factors explained by the model. MSE (mean square error) is the variance of the emission factors, and root MSE is the corresponding standard deviation.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, "Analysis of the Relationship Between the Heat and Carbon Content of U.S. Coals," September 1992.

Carbon Dioxide Emission Factors by Coal Rank and State of Origin

The (arithmetic) average emission factors obtained from the individual samples (assuming complete combustion) (Table FE4)[10] confirm the long-recognized finding that anthracite emits the largest amount of carbon dioxide per million Btu, followed by lignite, subbituminous coal, and bituminous coal. The high carbon dioxide emission factor for anthracite reflects the coal's relatively small hydrogen content, which lowers its heating value.[11] In pounds of carbon dioxide per million Btu, U.S. average factors are 227.4 for anthracite, 216.3 for lignite, 211.9 for subbituminous coal, and 205.3 for bituminous coal.

Table FE4. Average Carbon Dioxide Emission Factors for Coal by Rank and State of Origin

State of Origin	Anthracite	Bituminous	Sub-bituminous	Lignite
Alabama	--	205.5	--	--
Alaska	--	--	[a]214.0	--
Arizona	--	209.7	--	--
Arkansas	--	211.6	--	[b]213.5
California	--	--	--	[c]216.3
Colorado	--	206.2	212.7	--

Georgia	--	206.1	--	--
Idaho	--	205.9	--	--
Illinois	--	203.5	--	--
Indiana	--	203.6	--	--
Iowa	--	201.6	[d]207.2	--
Kansas	--	202.8	--	--
Kentucky: East	--	204.8	--	--
Kentucky: West	--	203.2	--	--
Louisiana	--	--	--	[b]213.5
Maryland	--	210.2	--	--
Missouri	--	201.3	--	--
Montana	--	209.6	213.4	220.6
Nevada	--	201.8	--	--
New Mexico	--	205.7	[e]208.8	--
North Dakota	--	--	--	218.8
Ohio	--	202.8	--	--
Oklahoma	--	205.9	--	--
Oregon	--	--	210.4	--
Pennsylvania	227.4	205.7	--	--
South Dakota	--	--	--	217.0
Tennessee	--	204.8	--	--
Texas	--	[f]204.4	--	213.5
Utah	--	204.1	207.1	--
Virginia	--	206.2	--	--
Washington	--	203.6	208.7	211.7
West Virginia	--	207.1	--	--
Wyoming	--	206.5	212.7	215.6
U.S. Average	**227.4**	**205.3**	**211.9**	**216.3**

[a]Based on carbon and heat content data supplied by Usibelli Coal Mining Company for the subbituminous C coal currently being produced in the State.

[b]Based on the CO_2 emission factor for Texas lignite.

[c]Based on the CO_2 emission factor for U.S. lignite.

[d]Derived from "Element Geochemistry of Cherokee Group Coals (Middle Pennsylvanian) from South-Central and Southeastern Iowa," *Technical Paper No. 5*, Iowa Geological Survey (Iowa City, IA, 1984), pp. 15, 48, and 49.

[e]Based on the CO_2 emission factor for subbituminous A coal.

[f]Based on the CO_2 ratio for U.S. high-volatile bituminous coal.

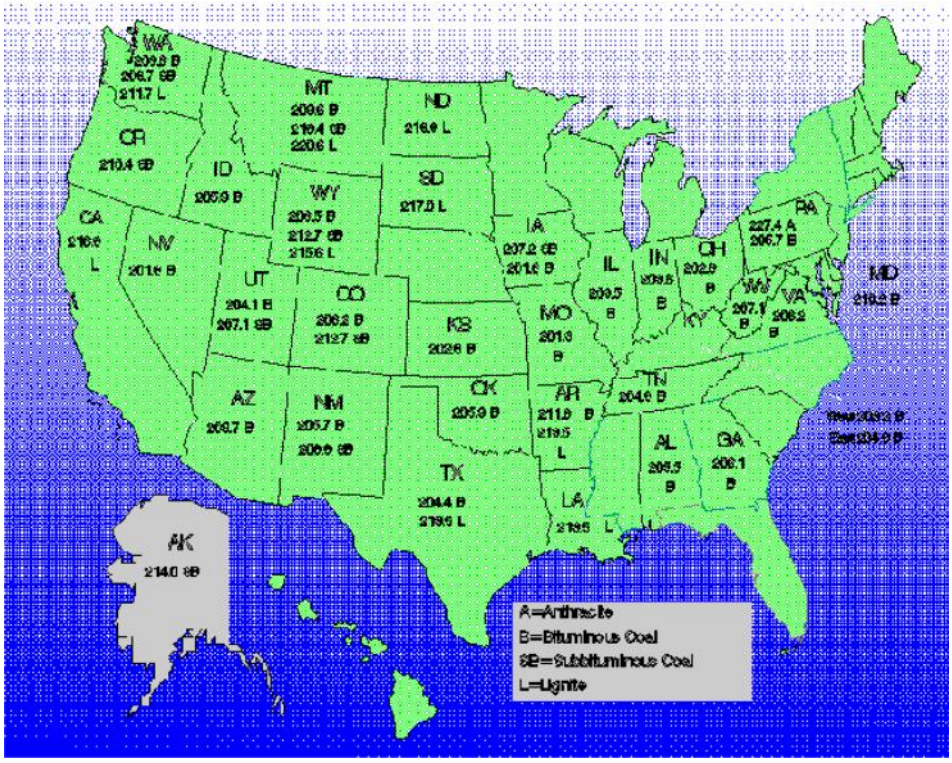
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, "Analysis of the Relationship Between the Heat and Carbon Content of U.S. Coals," September 1992.

In general, the carbon dioxide emission factors are lowest for coal produced in States east of the Mississippi River (Figure FE1), where the predominant coals are bituminous in rank and therefore have relatively low emission factors. By comparison, the coal deposits in the West are largely subbituminous coals, which have relatively high emission factors. In a broad sense, the geographic differences reflect the greater degree of coalification--the process that transformed plant material into coal under the influence of heat and pressure--in the coal-bearing areas in the East.

In the Appalachian Coal Basin, the emission factors for bituminous coal range from a low of 202.8 pounds of carbon dioxide per million Btu in Ohio to a high of 210.2 in Maryland.[(12)] Pennsylvania anthracite, which is produced in small amounts, has the highest emission factor among all coal ranks (227.4). For Illinois Basin coal, all bituminous in rank, the emission factors are relatively uniform, ranging from 203.2 in western Kentucky to 203.6 in Indiana.

Figure FE1: Average Carbon Dioxide Emission Factors for Coal by Rank and State of Origin

Pounds of Carbon Dioxide per Million Btu



West of the Mississippi River, the emission factors for bituminous coal range from more than 201 pounds of carbon dioxide per million Btu in Missouri, Iowa, and Nevada to more than 209 in Arizona, Arkansas, and Montana. About 16 percent of the 1992 coal output west of the Mississippi was bituminous coal, with production chiefly from Utah, Arizona, Colorado, and New Mexico.

Subbituminous coal is the predominant rank of coal produced west of the Mississippi River, accounting for 62 percent of the region's total coal output in 1992. Subbituminous coal in Wyoming's Powder River Basin, the principal source of this rank of coal, has an emission factor of 212.7 pounds of carbon dioxide per million Btu. This is the same as for subbituminous coal in Colorado, but slightly below that in Montana. The lowest emission factor for subbituminous coal is in Utah (207.1) and the highest is in Alaska (214.0).

The emission factor for lignite from the Gulf Coast Coal Region in Texas, Louisiana, and Arkansas is 213.5 pounds of carbon dioxide per million Btu. This is 1 to 3 percent lower than the emission factors for lignite in the Fort Union Coal Region in North Dakota, South Dakota, and Montana and for lignite in the Powder River Basin in Wyoming. The 1992 output of lignite accounted for 22 percent of coal production west of the Mississippi River, with two-thirds from Texas and most of the balance from North Dakota.

All of EIA's carbon dioxide emission factors for coal by rank and State of origin should be considered as "fixed" for the foreseeable future. This is because detailed coal analysis data are not widely available annually, and because the EIA emission factors, as developed from the EIA Coal Analysis File, are considered to effectively represent the relationship between the carbon and heat content of the various U.S. coals. However, the basic emission factors will be reviewed when sufficient additional coal analysis data are accumulated.

Carbon Dioxide Emission Factors by Coal-Consuming Sector and State

Coal use among the consuming sectors and States varies in quantity as well as in rank and State of origin. Therefore, emission factors by consuming sector in each State were derived by weighting the emission factors by coal rank and State of origin by the respective amounts received by sector.[(13),(14)] For comparison, emission factors for 1980 and 1992 are reported in this article (Table FE5). It should be noted that the amount of coal received in a certain year may not equal the amount consumed during that year because of stock additions or withdrawals. Furthermore, because data on the origin and destination of coal are available only for coal distribution, EIA's emission factors for coal consumption by sector assume that the mix of coal received during a certain year was the same as that consumed in that year.

The emission factors for coal consumption involving combustion are based on the assumption that all of the carbon in coal is converted to carbon dioxide during combustion. Actually, a very small percentage of the carbon in coal is not oxidized during combustion. The emission factors in Table FE5 can be adjusted to reflect incomplete combustion.[(15)]

In coke plants, coal is carbonized, not combusted, to make coke, which is used in the manufacture of pig iron by the iron and steel industry. Although most of the carbon in the coal carbonized remains in the coke, a small amount is retained in byproducts, some of which are consumed as energy sources and others as non-energy raw materials.[(16)] Examination of historical data for coke plant operations indicates that about 10 percent of the carbon in coking coal remains in non- energy byproducts.[(17)] However, no allowances have been made in the emission factors for coke plants (Table FE5) for carbon retained in non-energy byproducts, leaving any adjustments to the user's stipulations.

Table FE5. Average Carbon Dioxide Emission Factors for Coal-Consuming Sector and State, 1980 and 1992

State	Sector

	Electric Utilities		Industrial				Residential/Commercial		State Average[b]	
			Coking Coal[a]		Other Coal					
	1980	**1992**	**1980**	**1992**	**1980**	**1992**	**1980**	**1992**	**1980**	**1992**
Alabama	205.0	205.3	205.5	206.1	205.5	205.7	205.4	205.5	205.1	205.4
Alaska	214.0	214.0	--	--	--	--	--	214.0	214.0	214.0
Arizona	208.0	207.7	--	--	209.2	206.7	--	208.6	208.1	207.6
Arkansas	212.7	212.7	--	--	201.4	205.2	205.3	222.3	210.7	212.5
California	--	--	208.7	--	205.6	204.2	204.5	204.1	207.5	204.1
Colorado	211.5	209.8	212.6	--	212.6	212.5	212.6	211.0	211.7	209.9
Connecticut	--	204.9	--	--	--	204.7	226.1	220.2	226.1	205.2
Delaware	206.0	206.9	--	--	205.9	207.4	221.8	221.1	206.0	207.0
District of Columbia	--	--	--	--	205.0	--	205.5	206.3	205.4	206.3
Florida	204.0	204.4	--	--	204.2	205.1	205.0	205.7	204.0	204.5
Georgia	204.3	204.8	--	--	204.9	204.9	204.7	204.9	204.3	204.8
Hawaii	--	--	--	--	--	204.4	--	--	--	204.4
Idaho	--	--	--	--	212.6	212.2	205.4	205.0	210.7	211.3
Illinois	207.1	206.2	205.2	206.5	204.2	203.7	203.9	203.9	206.7	205.9
Indiana	204.0	205.6	205.0	206.0	203.7	204.5	203.7	203.8	204.3	205.5
Iowa	207.2	211.1	--	--	205.7	208.3	205.1	204.2	207.0	210.7
Kansas	209.2	210.9	--	--	201.9	205.3	202.2	202.9	209.0	210.8
Kentucky	204.0	204.1	204.6	206.3	205.4	205.4	204.6	204.6	204.1	204.2
Louisiana	212.7	212.9	--	--	203.9	210.9	201.3	--	212.1	212.8
Maine	--	--	--	--	206.0	204.9	216.2	213.0	207.9	205.3
Maryland	206.6	207.0	205.9	--	206.1	208.4	210.6	211.7	206.3	207.1
Massachusetts	206.4	206.8	--	--	206.3	207.0	218.2	214.1	207.6	206.9
Michigan	206.0	208.9	205.5	--	204.8	205.3	205.0	205.0	205.7	208.5
Minnesota	212.9	213.0	--	--	211.6	211.8	208.6	212.3	212.7	212.9
Mississippi	204.7	204.5	--	--	204.0	204.6	202.6	227.4	204.7	204.5
Missouri	204.5	206.2	205.2	--	203.6	204.5	202.1	203.4	204.5	206.1
Montana	213.9	213.5	--	--	211.2	211.4	205.6	213.3	213.7	213.5
Nebraska	211.7	212.7	--	--	212.3	213.1	212.6	219.2	211.7	212.7
Nevada	208.2	208.4	--	--	204.5	204.1	208.4	204.1	208.1	208.3
New Hampshire	206.9	206.3	--	--	207.0	207.1	227.2	225.4	207.0	206.5
New Jersey	206.6	206.6	--	--	218.3	207.3	227.2	227.1	207.1	206.8
New Mexico	205.7	205.7	--	--	212.0	212.7	209.8	206.3	205.7	205.7
New York	205.7	206.1	205.5	206.1	206.9	207.0	218.9	218.0	206.3	206.5
North Carolina	205.6	205.8	--	--	204.8	205.7	204.9	206.2	205.6	205.8
North Dakota	218.8	218.8	--	--	218.8	218.3	218.5	216.8	218.8	218.6
Ohio	204.4	204.4	205.4	206.4	204.0	204.5	203.8	205.5	204.5	204.6
Oklahoma	210.5	212.6	--	--	202.2	207.5	205.7	207.0	210.0	212.3
Oregon	212.7	212.9	--	--	212.7	211.5	205.6	204.1	212.5	212.8
Pennsylvania	206.1	206.2	205.7	206.1	207.9	208.5	221.2	219.7	206.4	206.7
Rhode Island	--	--	--	--	210.0	--	223.9	227.4	217.2	227.4
South Carolina	204.9	205.0	--	--	205.0	205.3	204.8	205.3	204.9	205.0
South Dakota	218.1	218.8	--	--	210.5	212.7	212.0	212.8	217.6	217.9
Tennessee	204.0	204.0	210.2	--	204.8	205.5	204.5	204.6	204.1	204.2
Texas	213.0	212.9	209.8	--	212.3	212.3	213.7	211.0	212.8	212.9
Utah	204.1	204.3	210.8	205.6	205.2	204.1	204.1	204.1	205.7	204.4
Vermont	205.7	--	--	--	207.8	212.2	227.4	227.4	216.0	216.8
Virginia	205.9	206.0	206.2	206.2	205.1	206.2	205.0	206.3	205.7	206.1
Washington	208.7	209.3	--	--	206.3	205.8	204.3	206.9	208.3	209.1
West Virginia	206.9	207.0	205.3	206.7	205.4	206.6	205.0	210.2	206.6	207.0
Wisconsin	207.0	209.9	205.4	--	205.5	206.1	205.8	204.9	206.8	209.5
Wyoming	212.7	212.0	--	--	212.0	212.5	212.3	212.7	212.6	212.1
U.S. Average[b]	**206.7**	**207.7**	**205.8**	**206.2**	**205.9**	**207.1**	**210.6**	**211.2**	**206.5**	**207.6**

[a]No allowances have been made for carbon retained in non-energy coal chemical byproducts from the coal carbonization process.
[b]Weighted average. The weights used are consumption values by sector.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

The mix of rank and origin of coal consumed in the United States has changed substantially in the past two decades, reflecting shifts to Western low-sulfur subbituminous coal and lignite, predominantly for electricity generation. Further changes are expected in the coming years, especially due to the Clean Air Act Amendments of 1990, which will encourage switches from high-sulfur Eastern bituminous coal to low-sulfur Western subbituminous coal.

The shift in the mix of coal ranks consumed becomes apparent when production by coal rank in 1980 is compared with that in 1992, as most production was for domestic consumption.(18) In 1980, bituminous coal comprised 76 percent of the total, but by 1992 its share

dropped to 65 percent. By contrast, the share for subbituminous coal rose from 18 percent in 1980 to 25 percent in 1992, while the share for lignite grew from 6 percent to 9 percent. Anthracite's share was about 1 percent in both years. Because lower rank coals have relatively high carbon dioxide emission factors, increased use of these coals caused the national average carbon dioxide emission factor to rise from 206.5 pounds per million Btu in 1980 to 207.6 pounds per million Btu in 1992.

The change in mix of coal ranks produced reflects the large sectorial and regional shifts in coal consumption that have occurred in the past two decades. The electric utility sector dominates coal consumption, and its share has grown substantially. Of total coal consumption in 1992, electric utilities accounted for 87 percent, up from 81 percent in 1980, due mostly to increases in utility coal consumption west of the Mississippi River.[(19)] The share held by low-rank coals in the electric utility sector increased substantially.[(20)] Subbituminous coal rose from 24 percent in 1980 to 31 percent in 1992, and lignite grew from 7 to 10 percent during the period. In contrast, bituminous coal fell from 69 percent in 1980 to 58 percent in 1992. The share held by anthracite (about 1 percent) did not change.

Coal used to produce coke is virtually all bituminous in rank; less than 1 percent is anthracite. Only a few States, mostly in Appalachia, supply coking coal. The coke industry, which has been declining, accounted for only 4 percent of total coal consumption in 1992, down from 9 percent in 1980.

All ranks of coal are used by the other industrial and the residential/commercial sectors.[(21)] The other industrial sector accounted for 8 percent of total coal consumption in 1992, slightly less than in 1980. However, the emission factor for this sector increased sizably during the period, due mainly to the rising use of low-rank coals in the West, and contributed to the increase in emission factors for the overall national average. The residential/commercial sector is a relatively minor component of coal consumption, with about 1 percent of the total in 1980 and 1992.

As with coal consumption by sector, the amount of carbon dioxide emitted from total coal combustion in a particular State--and hence the carbon dioxide emission factor for that State--depends on the mix of coal consumed by various consuming sectors in that State during a particular year. When the total energy in Btu from coal consumption by State is known (with no breakdown by coal-consuming sector), the State average emission factors can be used to estimate the total amount of carbon dioxide emissions by State.

Publication of Carbon Dioxide Emission Factors

EIA's carbon dioxide emission factors by consuming sector and State will be updated periodically to reflect changes in the mix of U.S. coal consumption. EIA plans to report these updates in the *Quarterly Coal Report*, the *State Energy Data Report*, and the annual issue of *Emissions of Greenhouse Gases in the United States*.

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[1]Coal combustion emits almost twice as much carbon dioxide per unit of energy as does the combustion of natural gas, whereas the amount from crude oil combustion falls between coal and natural gas, according to Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1985-1990*, DOE/EIA-0573 (Washington, DC, September 1993), p. 16.

[2]Examples of previously published emission factors include, in pounds of carbon dioxide per million Btu, single emission factors of 205.7 in "United States Emissions of Carbon Dioxide to the Earth's Atmosphere," *Energy Systems Policy*, Vol. 14, 1990, p. 323; 210.2 in *Changing by Degrees*, U.S. Congress, Office of Technology Assessment, February 1991, p. 333; 205.6 for bituminous coal in *Greenhouse Gases, Abatement and Control*, IEA Coal Research, June 1991, p. 24; and 183.4 in *Limiting Net Greenhouse Gas Emissions in the United States (Executive Summary)*, U.S. Department of Energy, Office of Environmental Analysis, September 1991, p. 37. EIA's first reported emission factors by coal rank, published in *Electric Power Annual 1990*, DOE/EIA-0348(90) (Washington, DC, January 1992), p. 124, were as follows: anthracite, 209; bituminous coal, 209; subbituminous coal, 219; and lignite, 213.

[3]U.S. Department of Energy, Pittsburgh Energy Technology Center, "A Coal Combustion Primer," *PETC Review*, Issue 2 (Pittsburgh, PA, September 1990), p. 17.

[4]The relationships of the various heat-producing components of coal are given in Dulong's formula, which provides a method for calculating the heating value of solid fuels. Dulong's formula is as follows: Btu per pound = 14,544C + 62,028(H - O ÷ 8) + 4,050S. C is carbon, H is hydrogen, O is oxygen, and S is sulfur, all expressed in percent by weight. The coefficients represent the approximate heating values of the respective components in Btu per pound. The term O ÷ 8 for hydrogen is a correction applied to account for the portion of hydrogen combined with oxygen to form water. For a further discussion of Dulong's formula, see Babcock and Wilcox Co., *Steam/Its Generation and Use*, 40th edition, 1992, p. 9-9.

[5]Potential carbon dioxide emissions can be calculated by use of the following formula: percent carbon ÷ Btu per pound x 36,670 = pounds (lbs) of carbon dioxide per million (10^6) Btu. Multiply pounds of carbon dioxide per million Btu by 0.123706 to get million metric tons (MMT) of carbon per quadrillion (10^{15}) Btu.

[6]Ultimate analysis refers to the determination of carbon, hydrogen, sulfur, nitrogen, oxygen, and ash. By comparison, proximate analysis determines fixed carbon, volatile matter, moisture, and ash. Fixed carbon is principally carbon, but it may contain appreciable amounts of sulfur, hydrogen, nitrogen, and oxygen. Volatile matter comprises hydrogen, carbon dioxide, carbon monoxide, and various compounds of carbon and hydrogen.

[7]Modification of the emission factors for incomplete combustion is described on page 6 of this article under "Carbon Dioxide Emission Factors by Coal-Consuming Sector and State."

[8]For details, see "Analysis of the Relationship Between the Heat and Carbon Content of U.S. Coals," prepared for the Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, by Science Applications International Corp., September 1992.

[9]Because of the unbalanced nature of the data being analyzed (i.e., unequal numbers of observations for the different levels of the classification variables), the General Linear Models procedure in the Statistical Analysis System was used to perform the analyses.

[10]The EIA Coal Analysis File did not contain data for bituminous coal in Texas, subbituminous coal in Alaska and New Mexico, or lignite in Arkansas, California, and Louisiana. The emission factor for Alaska subbituminous coal was derived from information obtained from the sole producer of coal in Alaska. The others were assigned appropriate average factors for their coal ranks, as noted in Table FE4.

[11]For the coal analyzed in the EIA Coal Analysis File, the average hydrogen content was as follows, by weight (dry basis): anthracite, 2.5 percent; bituminous coal, 5.0 percent; subbituminous coal, 4.8 percent; and lignite, 4.4 percent.

[12]For information on States that produce coal, see Energy Information Administration, *Coal Production 1992*, DOE/EIA-0118(92) (Washington, DC, October 1993), and *State Coal Profiles*, DOE/EIA-0576 (Washington, DC, January 1994).

[13]The amount of coal distributed by State of origin and State of destination is reported on Form EIA-6, "Coal Distribution Report," for consuming sectors other than electric utilities, and on Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," for utility coal by rank. The amount and energy content of coal consumption by State and sector are detailed in Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214, published annually.

[14]Acknowledgement is due Albert D. Gerard, Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, for assistance in developing Table FE5.

[15]Adjustments can be made by multiplying the factors by the estimated percentage of carbon converted to carbon dioxide. This has been estimated as 99 percent by G. Marland and A. Pippin, "United States Emissions of Carbon Dioxide to the Earth's Atmosphere by Economic Activity," *Energy Systems and Policy*, Vol. 14, (1990), p. 323. EIA's *Emissions of Greenhouse Gases in the United States 1985-1990* (DOE/EIA-0573, September 1993) also assumed 99 percent combustion for carbon emission estimates.

[16]Byproducts include coke oven gas, benzene, creosote, and other hydrocarbons. See, for example, Energy Information Administration, *Coke and Coal Chemicals in 1980*, DOE/EIA-012(80) (Washington, DC, May 1981), for production and disposition of coal chemical materials.

[17]Another source, *Greenhouse Gas Inventory Reference Manual--IPCC Draft Guideline for National Greenhouse Gas Inventories* (IPCC/OECD Joint Programme, 1993), Volume 3, part 2, 1.29, states that on average 5.91 percent of coal going to coke plants ends up as light oil and crude tar, with 75 percent of the carbon in these products remaining unoxidized for long periods.

[18]Energy Information Administration, *Coal Production 1980*, DOE/EIA-0118(80) (Washington, DC, May 1982), p. 20; and *Coal Production 1992*, DOE/EIA-0118(92) (Washington, DC, October 1993), p. 30.

[19]Energy Information Administration, *Quarterly Coal Report July-September 1993*, DOE/EIA-0121(93/3Q) (Washington, DC, February 1994), p. 77; and *Quarterly Coal Report October-December 1987*, DOE/EIA-0121 (87/4Q) (Washington, DC, May 1988), p. 46.

[20]Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1992*, DOE/EIA-019(92) (Washington, DC, August 1993), and *Cost and Quality of Fuels for Electric Utility Plants 1980 Annual*, DOE/EIA-0191(80) (Washington, DC, June 1981).

[21]Information on the rank of coal distributed to the other industrial and residential/commercial sectors from States producing more than one rank is not available. Therefore, based on available EIA data, the following coal ranks were assigned to distributions of nonutility coal from the following coal-producing States: Arkansas, bituminous; Colorado, Montana, Washington, and Wyoming, subbituminous; Texas, lignite.

Contact: Coal Experts

California Environmental Protection Agency
Air Resources Board

Last reviewed on June 17, 2016

California Greenhouse Gas Emission Inventory - 2016 Edition

2016 Edition of the GHG Emission Inventory Released (June 2016)

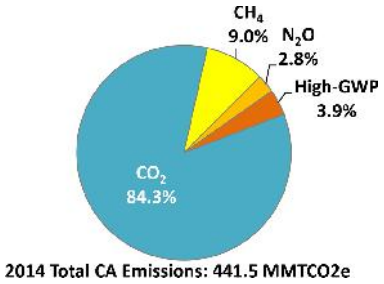
- GHG emissions from 2000 to 2014 are now available. Links to data and documentation can be found below.
- Carbon dioxide equivalent values are calculated using the IPCC's Fourth Assessment Report Global Warming Potential values. More information.

Background

California's annual statewide greenhouse gas (GHG) emission inventory is an important tool for establishing historical emission trends and tracking California's progress in reducing GHGs. In concert with data collected through various California Global Warming Solutions Act (AB 32) programs, the GHG inventory is a critical piece in demonstrating the state's progress in achieving the statewide GHG target. The inventory provides estimates of anthropogenic GHG emissions within California, as well as emissions associated with imported electricity; natural sources are not included in the inventory. The Air Resources Board (ARB) is responsible for maintaining and updating California's GHG Inventory per H&SC §39607.4.

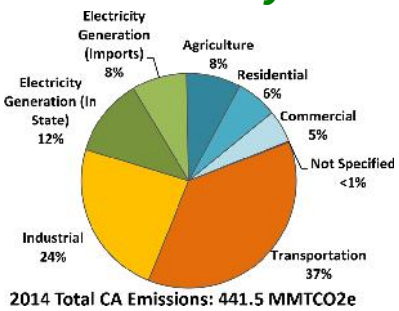
The inventory includes estimates for carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases with high global warming potentials (High-GWP) which includes sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and nitrogen trifluoride (NF_3). It uses an inventory scope and framework consistent with international and national GHG inventory practices. An updated emission inventory is published annually to include additional years and improved estimation methods. Archives of all previous inventory data and documentation are available on the archive page.

Emissions by GHG



Click the graph for more information

Emissions by Economic Sector



Data Overview

Statewide emission estimates rely on state, regional or federal data sources, and on aggregated facility-specific emission reports from ARB's Mandatory GHG Reporting Program (MRR). Calculation methodologies are consistent with the 2006 IPCC guidelines. The current inventory uses global warming potential (GWP) values from the IPCC Fourth Assessment Report, consistent with current international and national GHG inventory practices. Full documentation of data sources and methods is available below or by using the detailed documentation index.

In preparation for each new edition of the inventory, recalculations are made to correct errors, incorporate new methodologies or, most commonly, to reflect changes in statistical data supplied by other agencies. Emission estimates are recalculated for all years to maintain a consistent time-series following IPCC recommendations for developing GHG inventories. Thus the new inventory may report a different emission level for an earlier year than previous inventory editions.

The California GHG inventory is categorized in three ways:

1. Scoping Plan; follows the categories identified in the AB 32 Scoping Plan.
2. Economic sectors; allows for comparison with other ARB emission inventories, which are similarly categorized.
3. IPCC process-oriented categories; follows the IPCC categorization to ensure comparability with international inventories.

The table below provides a crosswalk among the three categorization schemes

- Inventory Categorization Crosswalk [Excel-55 KB]

Inventory Documentation

Download Reports

- 2000-2014 Emissions Trends Report [PDF-1,444 KB]
- 2000-2014 Frequently Asked Questions [PDF-87 KB]
- 2000-2014 Method Update Document [PDF-380 KB] - includes only methods that have changed for the 2000-2014 inventory.
- [COMING SOON] 2000-2014 Technical Support Document - a comprehensive methodology documentation that incorporates updates in the 2015 and 2016 inventory editions, as well as methods that are unchanged since the release of the 2000-2012 Technical Support Document.

Go To Detailed Documentation Index

- Interactive documentation index by IPCC category

Data Links

Download a Summary of the Inventory

- Scoping Plan Categorization PDF [84 KB] Excel [22 KB]
- Economic Sector Categorization PDF [92 KB] Excel [36 KB]
- IPCC Categorization PDF [116 KB] Excel [49 KB]
- Totals By Gas PDF [65 KB] Excel [15 KB]

Emission Summary Segregated by Gas

Categorization	CO_2 Only	CH_4 Only	N_2O Only	High-GWP Only
Scoping Plan	[PDF-80 KB]	[PDF-80 KB]	[PDF-81 KB]	[PDF-67 KB]
Economic Sector	[PDF-81 KB]	[PDF-80 KB]	[PDF-80 KB]	[PDF-67 KB]
IPPC Category	[PDF-92 KB]	[PDF-94 KB]	[PDF-92 KB]	[PDF-66 KB]

Download the Entire Inventory

- Scoping Plan Categorization [Excel-327 KB]
- Economic Sector Categorization [Excel-464 KB]
- IPCC Categorization [Excel-335 KB]

Query the Inventory

Query the inventory by economic sector and/or by activity. This interactive query tool allows you to select a subset of the inventory, graph it or download it to your computer. Each value also contains links to detailed methodology pages. More details on the query tool's help page.

Guidance for Working with GHG Inventory and MRR Data

The ARB Regulation for the Mandatory Reporting of GHG Emissions (MRR) is a primary data source for the statewide inventory but emissions are categorized differently in the two programs. Industrial

cogeneration (also known as Combined Heat and Power, or CHP) represents the major categorization difference. The guidance document below provides instruction for working with and crosswalking between the two datasets. A spreadsheet provides GHG inventory industrial cogeneration emissions disaggregation to facilitate comparison with MRR data.

- Guidance for Working with GHG Inventory and MRR Data Using the Industrial Cogeneration Breakout Table **[COMING SOON]**
- 2013 and 2014 Industrial Cogeneration Breakout **[COMING SOON]**

Other Useful Links

Current Inventory Graphs & Plots

Archive - data and documentation for all past inventories

Original (1990-2004) Inventory

GHG emissions prior to 2000 are included in the 1990-2004 GHG Emission Inventory published in November 2007 (data available in the 1990 Level & Limit section of this site). This inventory provided the basis for developing the 1990 statewide emission level and 2020 emission limit required by the Global Warming Solutions Act of 2006 (AB 32).

For general questions regarding California's Greenhouse Gas Emission Inventory, please contact: Anny Huang, Manager, Emission Inventory Analysis Section, Phone: (916) 323-8475

Climate Change 2014
Synthesis Report
Summary for Policymakers

Introduction

This Synthesis Report is based on the reports of the three Working Groups of the Intergovernmental Panel on Climate Change (IPCC), including relevant Special Reports. It provides an integrated view of climate change as the final part of the IPCC's Fifth Assessment Report (AR5).

This summary follows the structure of the longer report which addresses the following topics: Observed changes and their causes; Future climate change, risks and impacts; Future pathways for adaptation, mitigation and sustainable development; Adaptation and mitigation.

In the Synthesis Report, the certainty in key assessment findings is communicated as in the Working Group Reports and Special Reports. It is based on the author teams' evaluations of underlying scientific understanding and is expressed as a qualitative level of confidence (from *very low* to *very high*) and, when possible, probabilistically with a quantified likelihood (from *exceptionally unlikely* to *virtually certain*)[1]. Where appropriate, findings are also formulated as statements of fact without using uncertainty qualifiers.

This report includes information relevant to Article 2 of the United Nations Framework Convention on Climate Change (UNFCCC).

SPM 1. Observed Changes and their Causes

Human influence on the climate system is clear, and recent anthropogenic emissions of greenhouse gases are the highest in history. Recent climate changes have had widespread impacts on human and natural systems. ***{1}***

SPM 1.1 Observed changes in the climate system

Warming of the climate system is unequivocal, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, and sea level has risen. ***{1.1}***

Each of the last three decades has been successively warmer at the Earth's surface than any preceding decade since 1850. The period from 1983 to 2012 was *likely* the warmest 30-year period of the last 1400 years in the Northern Hemisphere, where such assessment is possible (*medium confidence*). The globally averaged combined land and ocean surface temperature data as calculated by a linear trend show a warming of 0.85 [0.65 to 1.06] °C[2] over the period 1880 to 2012, when multiple independently produced datasets exist (Figure SPM.1a). *{1.1.1, Figure 1.1}*

In addition to robust multi-decadal warming, the globally averaged surface temperature exhibits substantial decadal and interannual variability (Figure SPM.1a). Due to this natural variability, trends based on short records are very sensitive to the beginning and end dates and do not in general reflect long-term climate trends. As one example, the rate of warming over

[1] Each finding is grounded in an evaluation of underlying evidence and agreement. In many cases, a synthesis of evidence and agreement supports an assignment of confidence. The summary terms for evidence are: limited, medium or robust. For agreement, they are low, medium or high. A level of confidence is expressed using five qualifiers: very low, low, medium, high and very high, and typeset in italics, e.g., *medium confidence*. The following terms have been used to indicate the assessed likelihood of an outcome or a result: virtually certain 99–100% probability, very likely 90–100%, likely 66–100%, about as likely as not 33–66%, unlikely 0–33%, very unlikely 0–10%, exceptionally unlikely 0–1%. Additional terms (extremely likely 95–100%, more likely than not >50–100%, more unlikely than likely 0–<50%, extremely unlikely 0–5%) may also be used when appropriate. Assessed likelihood is typeset in italics, e.g., *very likely*. See for more details: Mastrandrea, M.D., C.B. Field, T.F. Stocker, O. Edenhofer, K.L. Ebi, D.J. Frame, H. Held, E. Kriegler, K.J. Mach, P.R. Matschoss, G.-K. Plattner, G.W. Yohe and F.W. Zwiers, 2010: Guidance Note for Lead Authors of the IPCC Fifth Assessment Report on Consistent Treatment of Uncertainties, Intergovernmental Panel on Climate Change (IPCC), Geneva, Switzerland, 4 pp.

[2] Ranges in square brackets or following '±' are expected to have a 90% likelihood of including the value that is being estimated, unless otherwise stated.

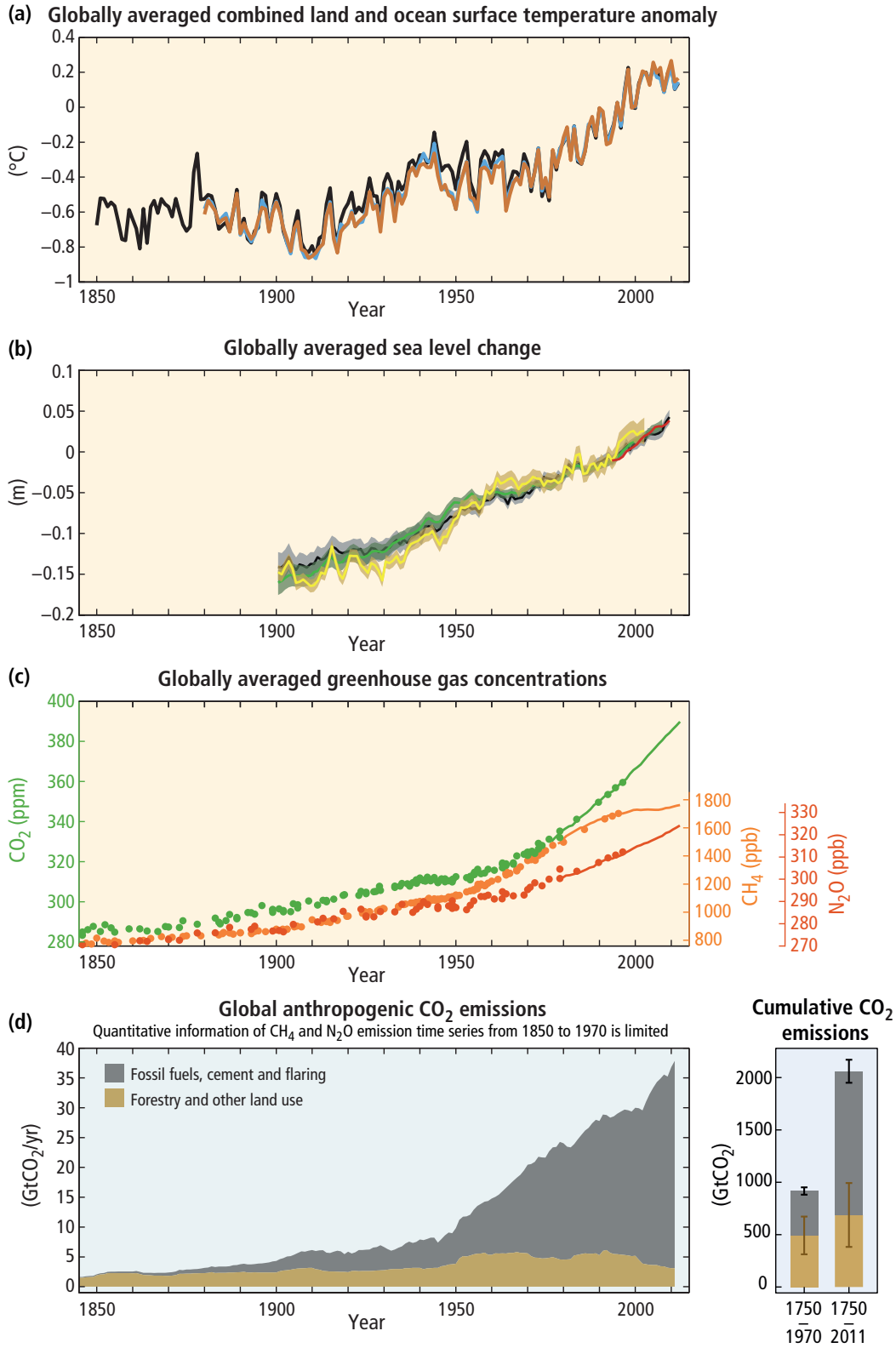


Figure SPM.1 | The complex relationship between the observations (panels a, b, c, yellow background) and the emissions (panel d, light blue background) is addressed in Section 1.2 and Topic 1. Observations and other indicators of a changing global climate system. Observations: **(a)** Annually and globally averaged combined land and ocean surface temperature anomalies relative to the average over the period 1986 to 2005. Colours indicate different data sets. **(b)** Annually and globally averaged sea level change relative to the average over the period 1986 to 2005 in the longest-running dataset. Colours indicate different data sets. All datasets are aligned to have the same value in 1993, the first year of satellite altimetry data (red). Where assessed, uncertainties are indicated by coloured shading. **(c)** Atmospheric concentrations of the greenhouse gases carbon dioxide (CO_2, green), methane (CH_4, orange) and nitrous oxide (N_2O, red) determined from ice core data (dots) and from direct atmospheric measurements (lines). Indicators: **(d)** Global anthropogenic CO_2 emissions from forestry and other land use as well as from burning of fossil fuel, cement production and flaring. Cumulative emissions of CO_2 from these sources and their uncertainties are shown as bars and whiskers, respectively, on the right hand side. The global effects of the accumulation of CH_4 and N_2O emissions are shown in panel c. Greenhouse gas emission data from 1970 to 2010 are shown in Figure SPM.2. *{Figures 1.1, 1.3, 1.5}*

the past 15 years (1998–2012; 0.05 [–0.05 to 0.15] °C per decade), which begins with a strong El Niño, is smaller than the rate calculated since 1951 (1951–2012; 0.12 [0.08 to 0.14] °C per decade). *{1.1.1, Box 1.1}*

Ocean warming dominates the increase in energy stored in the climate system, accounting for more than 90% of the energy accumulated between 1971 and 2010 (*high confidence*), with only about 1% stored in the atmosphere. On a global scale, the ocean warming is largest near the surface, and the upper 75 m warmed by 0.11 [0.09 to 0.13] °C per decade over the period 1971 to 2010. It is *virtually certain* that the upper ocean (0–700 m) warmed from 1971 to 2010, and it *likely* warmed between the 1870s and 1971. *{1.1.2, Figure 1.2}*

Averaged over the mid-latitude land areas of the Northern Hemisphere, precipitation has increased since 1901 (*medium confidence* before and *high confidence* after 1951). For other latitudes, area-averaged long-term positive or negative trends have *low confidence*. Observations of changes in ocean surface salinity also provide indirect evidence for changes in the global water cycle over the ocean (*medium confidence*). It is *very likely* that regions of high salinity, where evaporation dominates, have become more saline, while regions of low salinity, where precipitation dominates, have become fresher since the 1950s. *{1.1.1, 1.1.2}*

Since the beginning of the industrial era, oceanic uptake of CO_2 has resulted in acidification of the ocean; the pH of ocean surface water has decreased by 0.1 (*high confidence*), corresponding to a 26% increase in acidity, measured as hydrogen ion concentration. *{1.1.2}*

Over the period 1992 to 2011, the Greenland and Antarctic ice sheets have been losing mass (*high confidence*), *likely* at a larger rate over 2002 to 2011. Glaciers have continued to shrink almost worldwide (*high confidence*). Northern Hemisphere spring snow cover has continued to decrease in extent (*high confidence*). There is *high confidence* that permafrost temperatures have increased in most regions since the early 1980s in response to increased surface temperature and changing snow cover. *{1.1.3}*

The annual mean Arctic sea-ice extent decreased over the period 1979 to 2012, with a rate that was *very likely* in the range 3.5 to 4.1% per decade. Arctic sea-ice extent has decreased in every season and in every successive decade since 1979, with the most rapid decrease in decadal mean extent in summer (*high confidence*). It is *very likely* that the annual mean Antarctic sea-ice extent increased in the range of 1.2 to 1.8% per decade between 1979 and 2012. However, there is *high confidence* that there are strong regional differences in Antarctica, with extent increasing in some regions and decreasing in others. *{1.1.3, Figure 1.1}*

Over the period 1901 to 2010, global mean sea level rose by 0.19 [0.17 to 0.21] m (Figure SPM.1b). The rate of sea level rise since the mid-19th century has been larger than the mean rate during the previous two millennia (*high confidence*). *{1.1.4, Figure 1.1}*

SPM 1.2 Causes of climate change

Anthropogenic greenhouse gas emissions have increased since the pre-industrial era, driven largely by economic and population growth, and are now higher than ever. This has led to atmospheric concentrations of carbon dioxide, methane and nitrous oxide that are unprecedented in at least the last 800,000 years. Their effects, together with those of other anthropogenic drivers, have been detected throughout the climate system and are *extremely likely* to have been the dominant cause of the observed warming since the mid-20th century. ***{1.2, 1.3.1}***

Anthropogenic greenhouse gas (GHG) emissions since the pre-industrial era have driven large increases in the atmospheric concentrations of carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) (Figure SPM.1c). Between 1750 and 2011, cumulative anthropogenic CO_2 emissions to the atmosphere were 2040 ± 310 $GtCO_2$. About 40% of these emissions have remained in the atmosphere (880 ± 35 $GtCO_2$); the rest was removed from the atmosphere and stored on land (in plants and soils) and in the ocean. The ocean has absorbed about 30% of the emitted anthropogenic CO_2, causing ocean acidification. About half of the anthropogenic CO_2 emissions between 1750 and 2011 have occurred in the last 40 years (*high confidence*) (Figure SPM.1d). *{1.2.1, 1.2.2}*

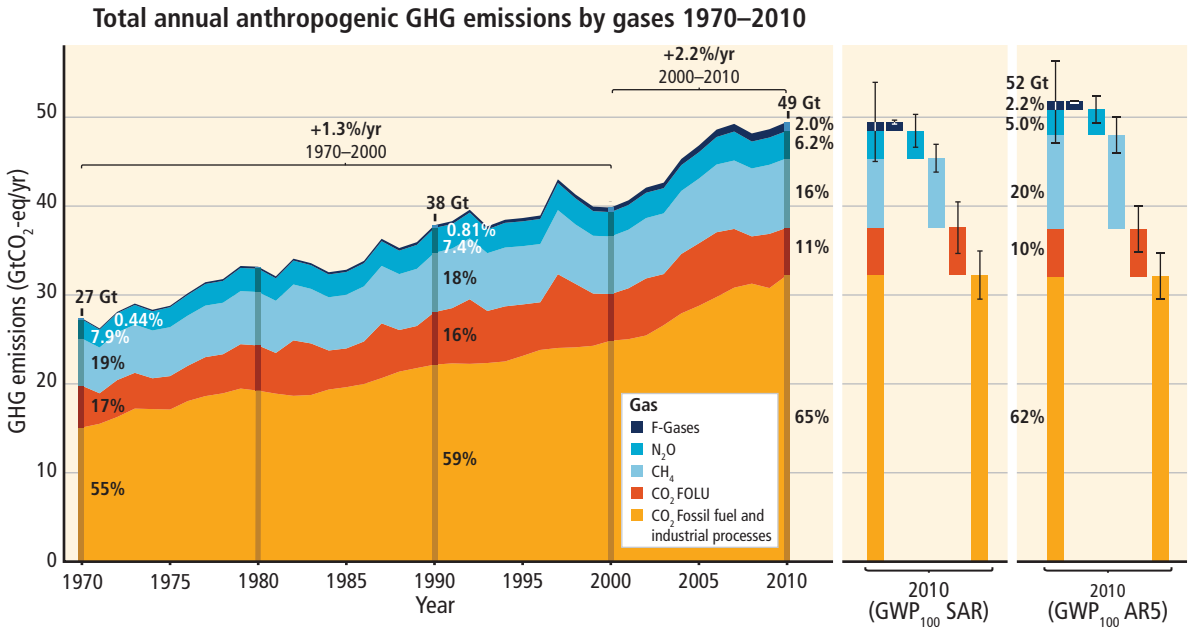


Figure SPM.2 | Total annual anthropogenic greenhouse gas (GHG) emissions (gigatonne of CO_2-equivalent per year, $GtCO_2$-eq/yr) for the period 1970 to 2010 by gases: CO_2 from fossil fuel combustion and industrial processes; CO_2 from Forestry and Other Land Use (FOLU); methane (CH_4); nitrous oxide (N_2O); fluorinated gases covered under the Kyoto Protocol (F-gases). Right hand side shows 2010 emissions, using alternatively CO_2-equivalent emission weightings based on IPCC Second Assessment Report (SAR) and AR5 values. Unless otherwise stated, CO_2-equivalent emissions in this report include the basket of Kyoto gases (CO_2, CH_4, N_2O as well as F-gases) calculated based on 100-year Global Warming Potential (GWP_{100}) values from the SAR (see Glossary). Using the most recent GWP_{100} values from the AR5 (right-hand bars) would result in higher total annual GHG emissions (52 $GtCO_2$-eq/yr) from an increased contribution of methane, but does not change the long-term trend significantly. *{Figure 1.6, Box 3.2}*

Total anthropogenic GHG emissions have continued to increase over 1970 to 2010 with larger absolute increases between 2000 and 2010, despite a growing number of climate change mitigation policies. Anthropogenic GHG emissions in 2010 have reached 49 ± 4.5 $GtCO_2$-eq/yr [3]. Emissions of CO_2 from fossil fuel combustion and industrial processes contributed about 78% of the total GHG emissions increase from 1970 to 2010, with a similar percentage contribution for the increase during the period 2000 to 2010 (*high confidence*) (Figure SPM.2). Globally, economic and population growth continued to be the most important drivers of increases in CO_2 emissions from fossil fuel combustion. The contribution of population growth between 2000 and 2010 remained roughly identical to the previous three decades, while the contribution of economic growth has risen sharply. Increased use of coal has reversed the long-standing trend of gradual decarbonization (i.e., reducing the carbon intensity of energy) of the world's energy supply (*high confidence*). *{1.2.2}*

The evidence for human influence on the climate system has grown since the IPCC Fourth Assessment Report (AR4). It is *extremely likely* that more than half of the observed increase in global average surface temperature from 1951 to 2010 was caused by the anthropogenic increase in GHG concentrations and other anthropogenic forcings together. The best estimate of the human-induced contribution to warming is similar to the observed warming over this period (Figure SPM.3). Anthropogenic forcings have *likely* made a substantial contribution to surface temperature increases since the mid-20th century over every continental region except Antarctica[4]. Anthropogenic influences have *likely* affected the global water cycle since 1960 and contributed to the retreat of glaciers since the 1960s and to the increased surface melting of the Greenland ice sheet since 1993. Anthropogenic influences have *very likely* contributed to Arctic sea-ice loss since 1979 and have *very likely* made a substantial contribution to increases in global upper ocean heat content (0–700 m) and to global mean sea level rise observed since the 1970s. *{1.3, Figure 1.10}*

[3] Greenhouse gas emissions are quantified as CO_2-equivalent ($GtCO_2$-eq) emissions using weightings based on the 100-year Global Warming Potentials, using IPCC Second Assessment Report values unless otherwise stated. *{Box 3.2}*

[4] For Antarctica, large observational uncertainties result in *low confidence* that anthropogenic forcings have contributed to the observed warming averaged over available stations.

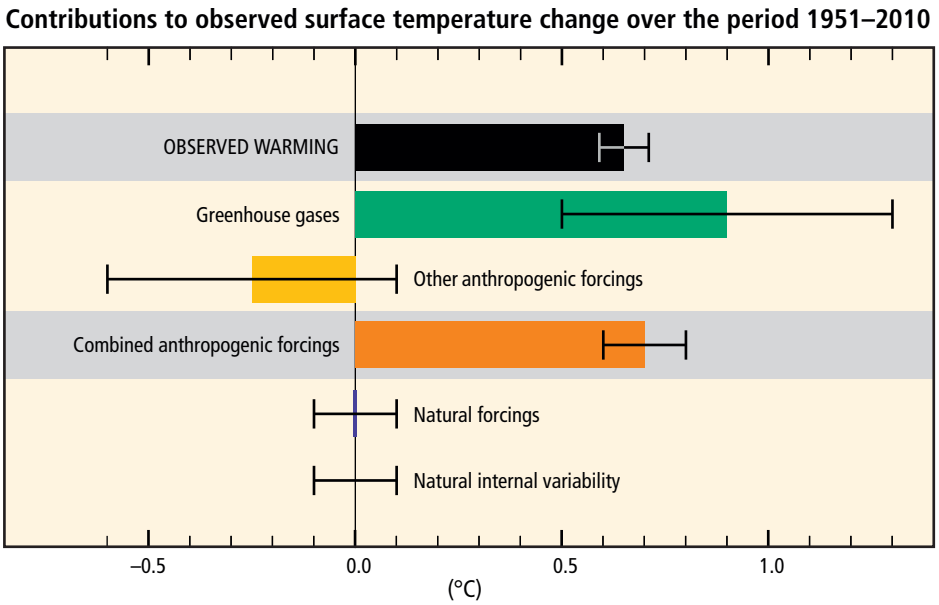


Figure SPM.3 | Assessed *likely* ranges (whiskers) and their mid-points (bars) for warming trends over the 1951–2010 period from well-mixed greenhouse gases, other anthropogenic forcings (including the cooling effect of aerosols and the effect of land use change), combined anthropogenic forcings, natural forcings and natural internal climate variability (which is the element of climate variability that arises spontaneously within the climate system even in the absence of forcings). The observed surface temperature change is shown in black, with the 5 to 95% uncertainty range due to observational uncertainty. The attributed warming ranges (colours) are based on observations combined with climate model simulations, in order to estimate the contribution of an individual external forcing to the observed warming. The contribution from the combined anthropogenic forcings can be estimated with less uncertainty than the contributions from greenhouse gases and from other anthropogenic forcings separately. This is because these two contributions partially compensate, resulting in a combined signal that is better constrained by observations. *{Figure 1.9}*

SPM 1.3 Impacts of climate change

In recent decades, changes in climate have caused impacts on natural and human systems on all continents and across the oceans. Impacts are due to observed climate change, irrespective of its cause, indicating the sensitivity of natural and human systems to changing climate. ***{1.3.2}***

Evidence of observed climate change impacts is strongest and most comprehensive for natural systems. In many regions, changing precipitation or melting snow and ice are altering hydrological systems, affecting water resources in terms of quantity and quality (*medium confidence*). Many terrestrial, freshwater and marine species have shifted their geographic ranges, seasonal activities, migration patterns, abundances and species interactions in response to ongoing climate change (*high confidence*). Some impacts on human systems have also been attributed to climate change, with a major or minor contribution of climate change distinguishable from other influences (Figure SPM.4). Assessment of many studies covering a wide range of regions and crops shows that negative impacts of climate change on crop yields have been more common than positive impacts (*high confidence*). Some impacts of ocean acidification on marine organisms have been attributed to human influence (*medium confidence*). *{1.3.2}*

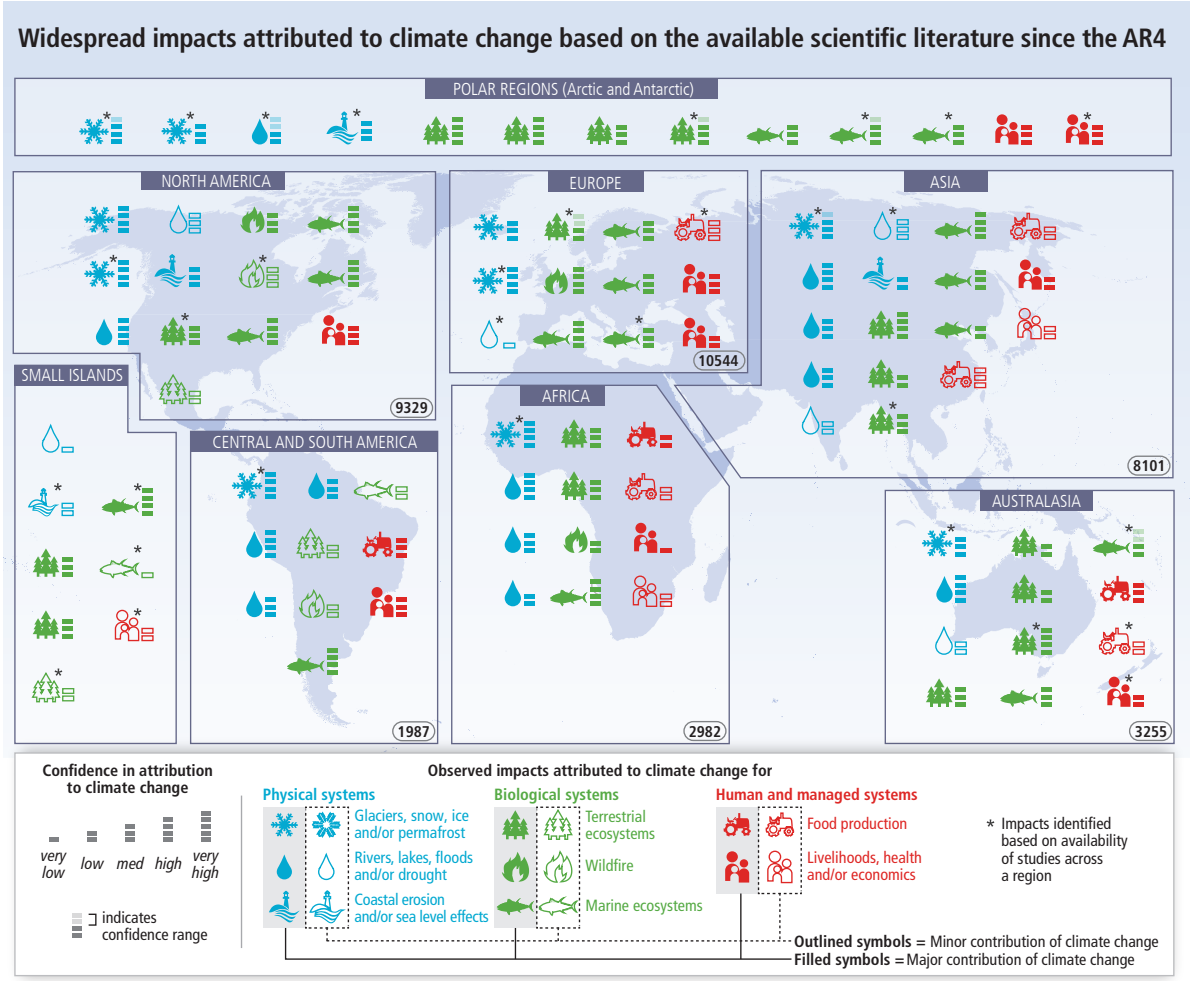


Figure SPM.4 | Based on the available scientific literature since the IPCC Fourth Assessment Report (AR4), there are substantially more impacts in recent decades now attributed to climate change. Attribution requires defined scientific evidence on the role of climate change. Absence from the map of additional impacts attributed to climate change does not imply that such impacts have not occurred. The publications supporting attributed impacts reflect a growing knowledge base, but publications are still limited for many regions, systems and processes, highlighting gaps in data and studies. Symbols indicate categories of attributed impacts, the relative contribution of climate change (major or minor) to the observed impact and confidence in attribution. Each symbol refers to one or more entries in WGII Table SPM.A1, grouping related regional-scale impacts. Numbers in ovals indicate regional totals of climate change publications from 2001 to 2010, based on the Scopus bibliographic database for publications in English with individual countries mentioned in title, abstract or key words (as of July 2011). These numbers provide an overall measure of the available scientific literature on climate change across regions; they do not indicate the number of publications supporting attribution of climate change impacts in each region. Studies for polar regions and small islands are grouped with neighbouring continental regions. The inclusion of publications for assessment of attribution followed IPCC scientific evidence criteria defined in WGII Chapter 18. Publications considered in the attribution analyses come from a broader range of literature assessed in the WGII AR5. See WGII Table SPM.A1 for descriptions of the attributed impacts. *{Figure 1.11}*

SPM 1.4 Extreme events

Changes in many extreme weather and climate events have been observed since about 1950. Some of these changes have been linked to human influences, including a decrease in cold temperature extremes, an increase in warm temperature extremes, an increase in extreme high sea levels and an increase in the number of heavy precipitation events in a number of regions. *{1.4}*

It is *very likely* that the number of cold days and nights has decreased and the number of warm days and nights has increased on the global scale. It is *likely* that the frequency of heat waves has increased in large parts of Europe, Asia and Australia. It is

very likely that human influence has contributed to the observed global scale changes in the frequency and intensity of daily temperature extremes since the mid-20th century. It is *likely* that human influence has more than doubled the probability of occurrence of heat waves in some locations. There is *medium confidence* that the observed warming has increased heat-related human mortality and decreased cold-related human mortality in some regions. *{1.4}*

There are *likely* more land regions where the number of heavy precipitation events has increased than where it has decreased. Recent detection of increasing trends in extreme precipitation and discharge in some catchments implies greater risks of flooding at regional scale (*medium confidence*). It is *likely* that extreme sea levels (for example, as experienced in storm surges) have increased since 1970, being mainly a result of rising mean sea level. *{1.4}*

Impacts from recent climate-related extremes, such as heat waves, droughts, floods, cyclones and wildfires, reveal significant vulnerability and exposure of some ecosystems and many human systems to current climate variability (*very high confidence*). *{1.4}*

SPM 2. Future Climate Changes, Risks and Impacts

Continued emission of greenhouse gases will cause further warming and long-lasting changes in all components of the climate system, increasing the likelihood of severe, pervasive and irreversible impacts for people and ecosystems. Limiting climate change would require substantial and sustained reductions in greenhouse gas emissions which, together with adaptation, can limit climate change risks. *{2}*

SPM 2.1 Key drivers of future climate

Cumulative emissions of CO_2 largely determine global mean surface warming by the late 21st century and beyond. Projections of greenhouse gas emissions vary over a wide range, depending on both socio-economic development and climate policy. *{2.1}*

Anthropogenic GHG emissions are mainly driven by population size, economic activity, lifestyle, energy use, land use patterns, technology and climate policy. The Representative Concentration Pathways (RCPs), which are used for making projections based on these factors, describe four different 21st century pathways of GHG emissions and atmospheric concentrations, air pollutant emissions and land use. The RCPs include a stringent mitigation scenario (RCP2.6), two intermediate scenarios (RCP4.5 and RCP6.0) and one scenario with very high GHG emissions (RCP8.5). Scenarios without additional efforts to constrain emissions ('baseline scenarios') lead to pathways ranging between RCP6.0 and RCP8.5 (Figure SPM.5a). RCP2.6 is representative of a scenario that aims to keep global warming *likely* below 2°C above pre-industrial temperatures. The RCPs are consistent with the wide range of scenarios in the literature as assessed by WGIII[5]. *{2.1, Box 2.2, 4.3}*

Multiple lines of evidence indicate a strong, consistent, almost linear relationship between cumulative CO_2 emissions and projected global temperature change to the year 2100 in both the RCPs and the wider set of mitigation scenarios analysed in WGIII (Figure SPM.5b). Any given level of warming is associated with a range of cumulative CO_2 emissions[6], and therefore, e.g., higher emissions in earlier decades imply lower emissions later. *{2.2.5, Table 2.2}*

[5] Roughly 300 baseline scenarios and 900 mitigation scenarios are categorized by CO_2-equivalent concentration (CO_2-eq) by 2100. The CO_2-eq includes the forcing due to all GHGs (including halogenated gases and tropospheric ozone), aerosols and albedo change.

[6] Quantification of this range of CO_2 emissions requires taking into account non-CO_2 drivers.

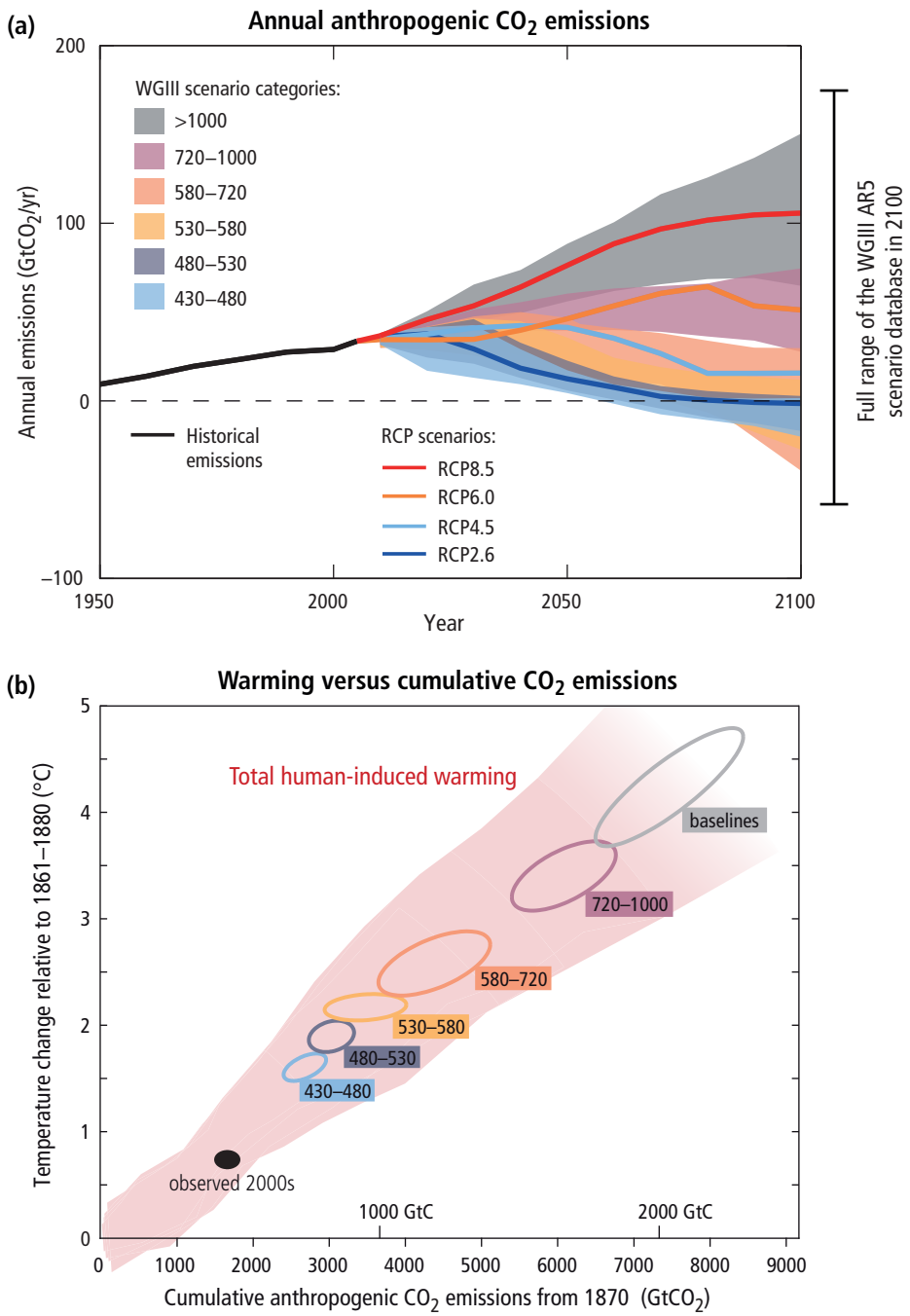


Figure SPM.5 | **(a)** Emissions of carbon dioxide (CO_2) alone in the Representative Concentration Pathways (RCPs) (lines) and the associated scenario categories used in WGIII (coloured areas show 5 to 95% range). The WGIII scenario categories summarize the wide range of emission scenarios published in the scientific literature and are defined on the basis of CO_2-eq concentration levels (in ppm) in 2100. The time series of other greenhouse gas emissions are shown in Box 2.2, Figure 1. **(b)** Global mean surface temperature increase at the time global CO_2 emissions reach a given net cumulative total, plotted as a function of that total, from various lines of evidence. Coloured plume shows the spread of past and future projections from a hierarchy of climate-carbon cycle models driven by historical emissions and the four RCPs over all times out to 2100, and fades with the decreasing number of available models. Ellipses show total anthropogenic warming in 2100 versus cumulative CO_2 emissions from 1870 to 2100 from a simple climate model (median climate response) under the scenario categories used in WGIII. The width of the ellipses in terms of temperature is caused by the impact of different scenarios for non-CO_2 climate drivers. The filled black ellipse shows observed emissions to 2005 and observed temperatures in the decade 2000–2009 with associated uncertainties. *{Box 2.2, Figure 1; Figure 2.3}*

Multi-model results show that limiting total human-induced warming to less than 2°C relative to the period 1861–1880 with a probability of >66%[7] would require cumulative CO_2 emissions from all anthropogenic sources since 1870 to remain below about 2900 $GtCO_2$ (with a range of 2550 to 3150 $GtCO_2$ depending on non-CO_2 drivers). About 1900 $GtCO_2$[8] had already been emitted by 2011. For additional context see Table 2.2. *{2.2.5}*

SPM 2.2 Projected changes in the climate system

Surface temperature is projected to rise over the 21st century under all assessed emission scenarios. It is *very likely* that heat waves will occur more often and last longer, and that extreme precipitation events will become more intense and frequent in many regions. The ocean will continue to warm and acidify, and global mean sea level to rise. *{2.2}*

The projected changes in Section SPM 2.2 are for 2081–2100 relative to 1986–2005, unless otherwise indicated.

Future climate will depend on committed warming caused by past anthropogenic emissions, as well as future anthropogenic emissions and natural climate variability. The global mean surface temperature change for the period 2016–2035 relative to 1986–2005 is similar for the four RCPs and will *likely* be in the range 0.3°C to 0.7°C (*medium confidence*). This assumes that there will be no major volcanic eruptions or changes in some natural sources (e.g., CH_4 and N_2O), or unexpected changes in total solar irradiance. By mid-21st century, the magnitude of the projected climate change is substantially affected by the choice of emissions scenario. *{2.2.1, Table 2.1}*

Relative to 1850–1900, global surface temperature change for the end of the 21st century (2081–2100) is projected to *likely* exceed 1.5°C for RCP4.5, RCP6.0 and RCP8.5 (*high confidence*). Warming is *likely* to exceed 2°C for RCP6.0 and RCP8.5 (*high confidence*), *more likely than not* to exceed 2°C for RCP4.5 (*medium confidence*), but *unlikely* to exceed 2°C for RCP2.6 (*medium confidence*). *{2.2.1}*

The increase of global mean surface temperature by the end of the 21st century (2081–2100) relative to 1986–2005 is *likely* to be 0.3°C to 1.7°C under RCP2.6, 1.1°C to 2.6°C under RCP4.5, 1.4°C to 3.1°C under RCP6.0 and 2.6°C to 4.8°C under RCP8.5[9]. The Arctic region will continue to warm more rapidly than the global mean (Figure SPM.6a, Figure SPM.7a). *{2.2.1, Figure 2.1, Figure 2.2, Table 2.1}*

It is *virtually certain* that there will be more frequent hot and fewer cold temperature extremes over most land areas on daily and seasonal timescales, as global mean surface temperature increases. It is *very likely* that heat waves will occur with a higher frequency and longer duration. Occasional cold winter extremes will continue to occur. *{2.2.1}*

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[7] Corresponding figures for limiting warming to 2°C with a probability of >50% and >33% are 3000 $GtCO_2$ (range of 2900 to 3200 $GtCO_2$) and 3300 $GtCO_2$ (range of 2950 to 3800 $GtCO_2$) respectively. Higher or lower temperature limits would imply larger or lower cumulative emissions respectively.

[8] This corresponds to about two thirds of the 2900 $GtCO_2$ that would limit warming to less than 2°C with a probability of >66%; to about 63% of the total amount of 3000 $GtCO_2$ that would limit warming to less than 2°C with a probability of >50%; and to about 58% of the total amount of 3300 $GtCO_2$ that would limit warming to less than 2°C with a probability of >33%.

[9] The period 1986–2005 is approximately 0.61 [0.55 to 0.67] °C warmer than 1850–1900. *{2.2.1}*

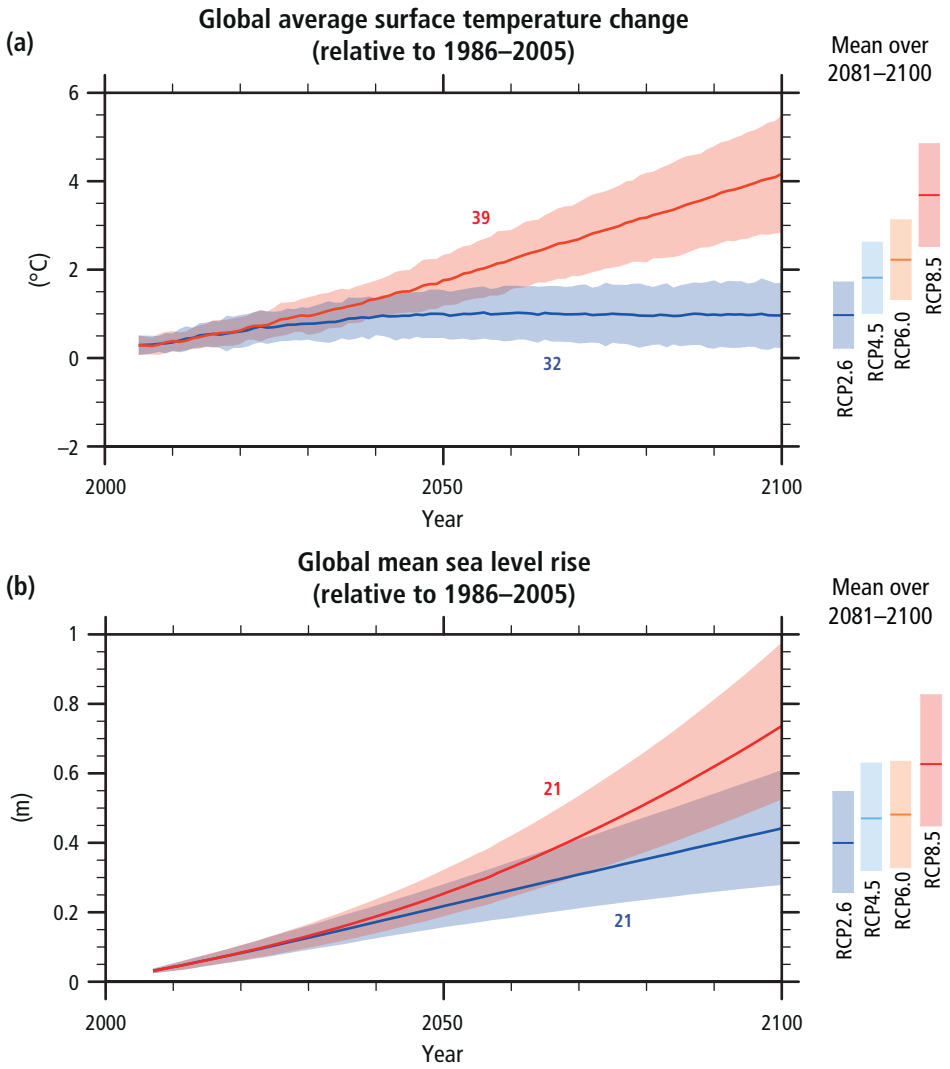


Figure SPM.6 | Global average surface temperature change **(a)** and global mean sea level rise[10] **(b)** from 2006 to 2100 as determined by multi-model simulations. All changes are relative to 1986–2005. Time series of projections and a measure of uncertainty (shading) are shown for scenarios RCP2.6 (blue) and RCP8.5 (red). The mean and associated uncertainties averaged over 2081–2100 are given for all RCP scenarios as coloured vertical bars at the right hand side of each panel. The number of Coupled Model Intercomparison Project Phase 5 (CMIP5) models used to calculate the multi-model mean is indicated. *{2.2, Figure 2.1}*

Changes in precipitation will not be uniform. The high latitudes and the equatorial Pacific are *likely* to experience an increase in annual mean precipitation under the RCP8.5 scenario. In many mid-latitude and subtropical dry regions, mean precipitation will *likely* decrease, while in many mid-latitude wet regions, mean precipitation will *likely* increase under the RCP8.5 scenario (Figure SPM.7b). Extreme precipitation events over most of the mid-latitude land masses and over wet tropical regions will *very likely* become more intense and more frequent. *{2.2.2, Figure 2.2}*

The global ocean will continue to warm during the 21st century, with the strongest warming projected for the surface in tropical and Northern Hemisphere subtropical regions (Figure SPM.7a). *{2.2.3, Figure 2.2}*

[10] Based on current understanding (from observations, physical understanding and modelling), only the collapse of marine-based sectors of the Antarctic ice sheet, if initiated, could cause global mean sea level to rise substantially above the *likely* range during the 21st century. There is *medium confidence* that this additional contribution would not exceed several tenths of a meter of sea level rise during the 21st century.

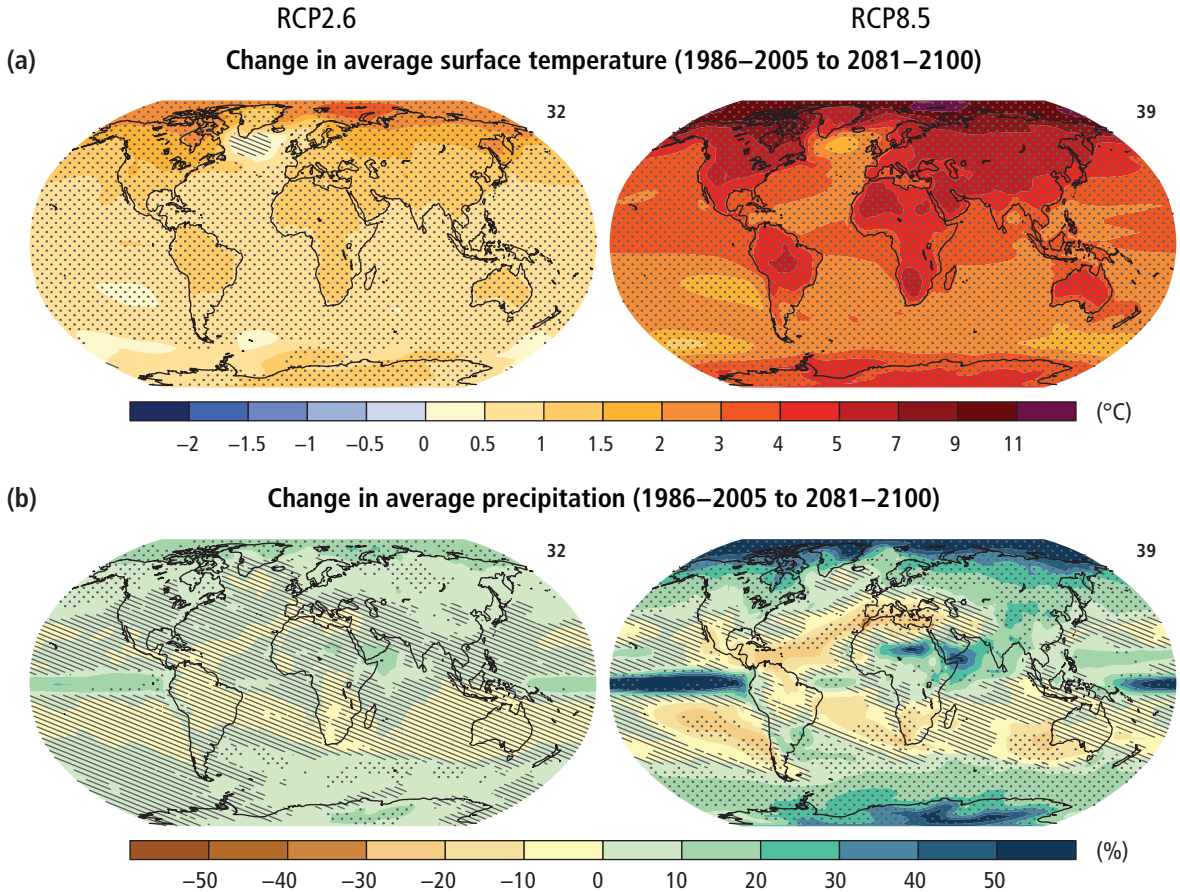


Figure SPM.7 | Change in average surface temperature **(a)** and change in average precipitation **(b)** based on multi-model mean projections for 2081–2100 relative to 1986–2005 under the RCP2.6 (left) and RCP8.5 (right) scenarios. The number of models used to calculate the multi-model mean is indicated in the upper right corner of each panel. Stippling (i.e., dots) shows regions where the projected change is large compared to natural internal variability and where at least 90% of models agree on the sign of change. Hatching (i.e., diagonal lines) shows regions where the projected change is less than one standard deviation of the natural internal variability. *{2.2, Figure 2.2}*

Earth System Models project a global increase in ocean acidification for all RCP scenarios by the end of the 21st century, with a slow recovery after mid-century under RCP2.6. The decrease in surface ocean pH is in the range of 0.06 to 0.07 (15 to 17% increase in acidity) for RCP2.6, 0.14 to 0.15 (38 to 41%) for RCP4.5, 0.20 to 0.21 (58 to 62%) for RCP6.0 and 0.30 to 0.32 (100 to 109%) for RCP8.5. *{2.2.4, Figure 2.1}*

Year-round reductions in Arctic sea ice are projected for all RCP scenarios. A nearly ice-free[11] Arctic Ocean in the summer sea-ice minimum in September before mid-century is *likely* for RCP8.5[12] (*medium confidence*). *{2.2.3, Figure 2.1}*

It is *virtually certain* that near-surface permafrost extent at high northern latitudes will be reduced as global mean surface temperature increases, with the area of permafrost near the surface (upper 3.5 m) projected to decrease by 37% (RCP2.6) to 81% (RCP8.5) for the multi-model average (*medium confidence*). *{2.2.3}*

The global glacier volume, excluding glaciers on the periphery of Antarctica (and excluding the Greenland and Antarctic ice sheets), is projected to decrease by 15 to 55% for RCP2.6 and by 35 to 85% for RCP8.5 (*medium confidence*). *{2.2.3}*

[11] When sea-ice extent is less than one million km^2 for at least five consecutive years.

[12] Based on an assessment of the subset of models that most closely reproduce the climatological mean state and 1979–2012 trend of the Arctic sea-ice extent.

There has been significant improvement in understanding and projection of sea level change since the AR4. Global mean sea level rise will continue during the 21st century, *very likely* at a faster rate than observed from 1971 to 2010. For the period 2081–2100 relative to 1986–2005, the rise will *likely* be in the ranges of 0.26 to 0.55 m for RCP2.6, and of 0.45 to 0.82 m for RCP8.5 (*medium confidence*)[10] (Figure SPM.6b). Sea level rise will not be uniform across regions. By the end of the 21st century, it is *very likely* that sea level will rise in more than about 95% of the ocean area. About 70% of the coastlines worldwide are projected to experience a sea level change within ±20% of the global mean. *{2.2.3}*

SPM 2.3 Future risks and impacts caused by a changing climate

Climate change will amplify existing risks and create new risks for natural and human systems. Risks are unevenly distributed and are generally greater for disadvantaged people and communities in countries at all levels of development. *{2.3}*

Risk of climate-related impacts results from the interaction of climate-related hazards (including hazardous events and trends) with the vulnerability and exposure of human and natural systems, including their ability to adapt. Rising rates and magnitudes of warming and other changes in the climate system, accompanied by ocean acidification, increase the risk of severe, pervasive and in some cases irreversible detrimental impacts. Some risks are particularly relevant for individual regions (Figure SPM.8), while others are global. The overall risks of future climate change impacts can be reduced by limiting the rate and magnitude of climate change, including ocean acidification. The precise levels of climate change sufficient to trigger abrupt and irreversible change remain uncertain, but the risk associated with crossing such thresholds increases with rising temperature (*medium confidence*). For risk assessment, it is important to evaluate the widest possible range of impacts, including low-probability outcomes with large consequences. *{1.5, 2.3, 2.4, 3.3, Box Introduction.1, Box 2.3, Box 2.4}*

A large fraction of species faces increased extinction risk due to climate change during and beyond the 21st century, especially as climate change interacts with other stressors (*high confidence*). Most plant species cannot naturally shift their geographical ranges sufficiently fast to keep up with current and high projected rates of climate change in most landscapes; most small mammals and freshwater molluscs will not be able to keep up at the rates projected under RCP4.5 and above in flat landscapes in this century (*high confidence*). Future risk is indicated to be high by the observation that natural global climate change at rates lower than current anthropogenic climate change caused significant ecosystem shifts and species extinctions during the past millions of years. Marine organisms will face progressively lower oxygen levels and high rates and magnitudes of ocean acidification (*high confidence*), with associated risks exacerbated by rising ocean temperature extremes (*medium confidence*). Coral reefs and polar ecosystems are highly vulnerable. Coastal systems and low-lying areas are at risk from sea level rise, which will continue for centuries even if the global mean temperature is stabilized (*high confidence*). *{2.3, 2.4, Figure 2.5}*

Climate change is projected to undermine food security (Figure SPM.9). Due to projected climate change by the mid-21st century and beyond, global marine species redistribution and marine biodiversity reduction in sensitive regions will challenge the sustained provision of fisheries productivity and other ecosystem services (*high confidence*). For wheat, rice and maize in tropical and temperate regions, climate change without adaptation is projected to negatively impact production for local temperature increases of 2°C or more above late 20th century levels, although individual locations may benefit (*medium confidence*). Global temperature increases of ~4°C or more[13] above late 20th century levels, combined with increasing food demand, would pose large risks to food security globally (*high confidence*). Climate change is projected to reduce renewable surface water and groundwater resources in most dry subtropical regions (*robust evidence*, *high agreement*), intensifying competition for water among sectors (*limited evidence*, *medium agreement*). *{2.3.1, 2.3.2}*

[13] Projected warming averaged over land is larger than global average warming for all RCP scenarios for the period 2081–2100 relative to 1986–2005. For regional projections, see Figure SPM.7. *{2.2}*

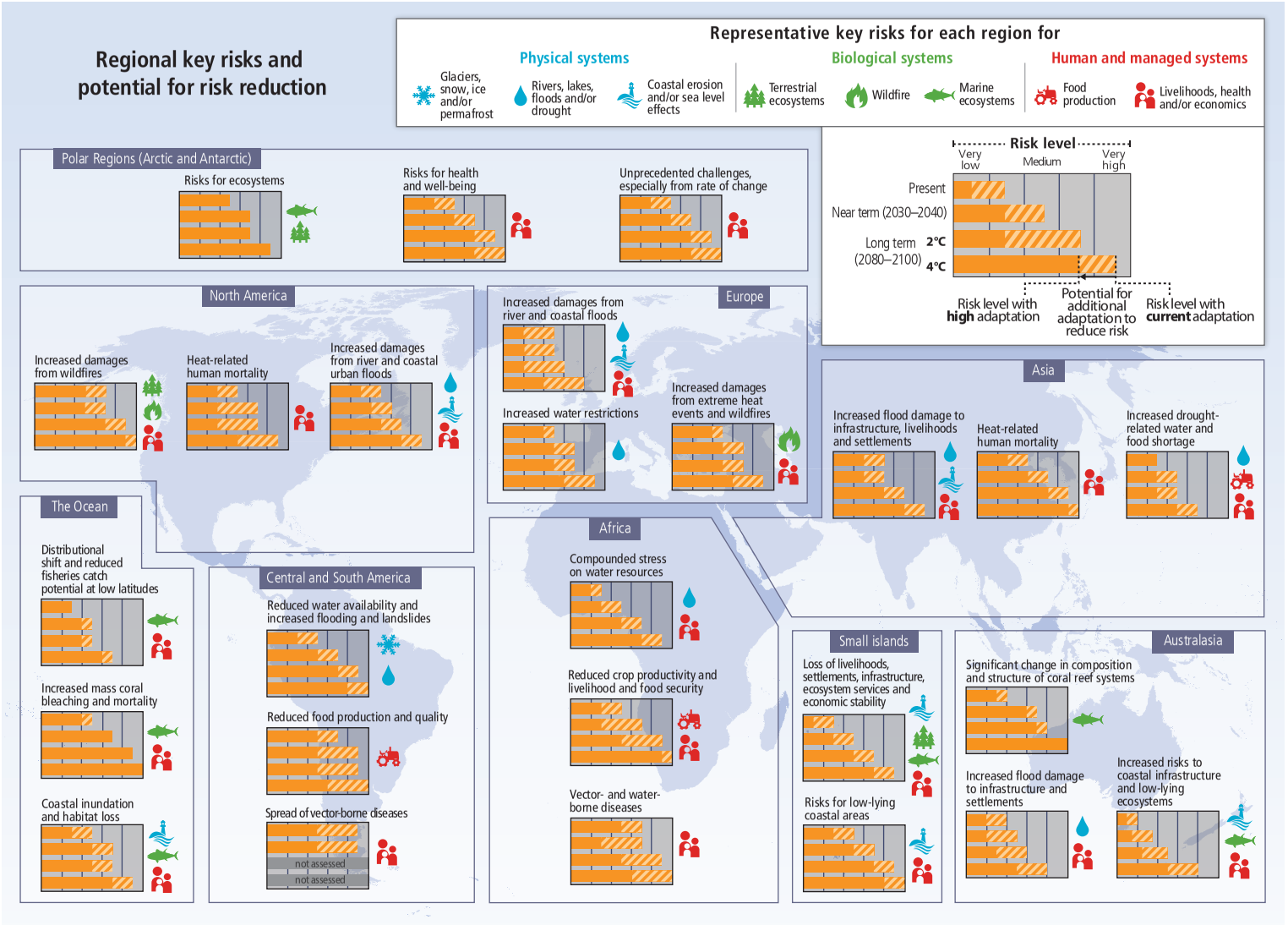


Figure SPM.8 | Representative key risks[14] for each region, including the potential for risk reduction through adaptation and mitigation, as well as limits to adaptation. Each key risk is assessed as very low, low, medium, high or very high. Risk levels are presented for three time frames: present, near term (here, for 2030–2040) and long term (here, for 2080–2100). In the near term, projected levels of global mean temperature increase do not diverge substantially across different emission scenarios. For the long term, risk levels are presented for two possible futures (2°C and 4°C global mean temperature increase above pre-industrial levels). For each timeframe, risk levels are indicated for a continuation of current adaptation and assuming high levels of current or future adaptation. Risk levels are not necessarily comparable, especially across regions. *{Figure 2.4}*

[14] Identification of key risks was based on expert judgment using the following specific criteria: large magnitude, high probability or irreversibility of impacts; timing of impacts; persistent vulnerability or exposure contributing to risks; or limited potential to reduce risks through adaptation or mitigation.

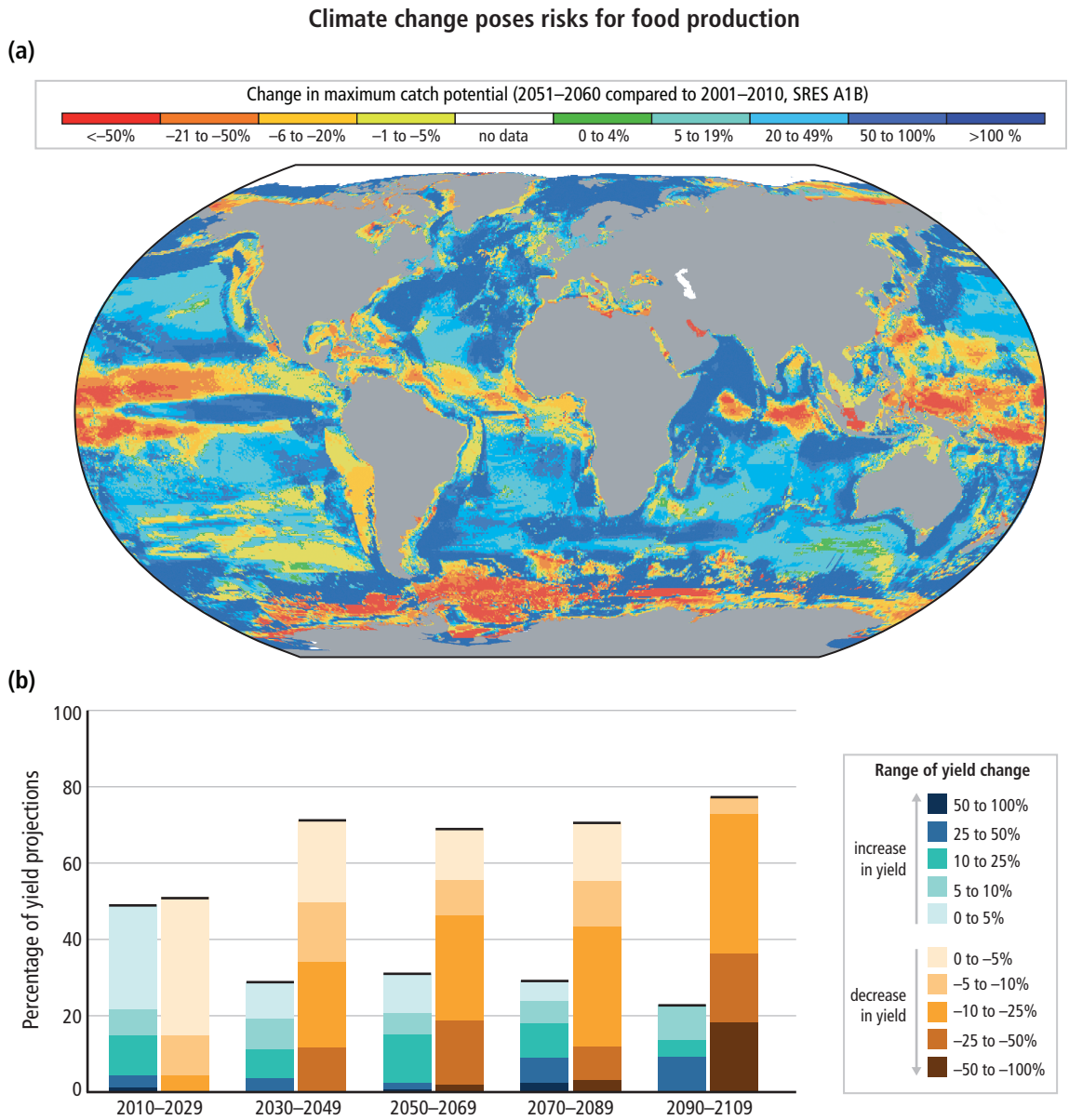


Figure SPM.9 | **(a)** Projected global redistribution of maximum catch potential of ~1000 exploited marine fish and invertebrate species. Projections compare the 10-year averages 2001–2010 and 2051–2060 using ocean conditions based on a single climate model under a moderate to high warming scenario, without analysis of potential impacts of overfishing or ocean acidification. **(b)** Summary of projected changes in crop yields (mostly wheat, maize, rice and soy), due to climate change over the 21st century. Data for each timeframe sum to 100%, indicating the percentage of projections showing yield increases versus decreases. The figure includes projections (based on 1090 data points) for different emission scenarios, for tropical and temperate regions and for adaptation and no-adaptation cases combined. Changes in crop yields are relative to late 20th century levels. *{Figure 2.6a, Figure 2.7}*

Until mid-century, projected climate change will impact human health mainly by exacerbating health problems that already exist (*very high confidence*). Throughout the 21st century, climate change is expected to lead to increases in ill-health in many regions and especially in developing countries with low income, as compared to a baseline without climate change (*high confidence*). By 2100 for RCP8.5, the combination of high temperature and humidity in some areas for parts of the year is expected to compromise common human activities, including growing food and working outdoors (*high confidence*). *{2.3.2}*

In urban areas climate change is projected to increase risks for people, assets, economies and ecosystems, including risks from heat stress, storms and extreme precipitation, inland and coastal flooding, landslides, air pollution, drought, water scarcity, sea level rise and storm surges (*very high confidence*). These risks are amplified for those lacking essential infrastructure and services or living in exposed areas. *{2.3.2}*

Rural areas are expected to experience major impacts on water availability and supply, food security, infrastructure and agricultural incomes, including shifts in the production areas of food and non-food crops around the world (*high confidence*). *{2.3.2}*

Aggregate economic losses accelerate with increasing temperature (*limited evidence, high agreement*), but global economic impacts from climate change are currently difficult to estimate. From a poverty perspective, climate change impacts are projected to slow down economic growth, make poverty reduction more difficult, further erode food security and prolong existing and create new poverty traps, the latter particularly in urban areas and emerging hotspots of hunger (*medium confidence*). International dimensions such as trade and relations among states are also important for understanding the risks of climate change at regional scales. *{2.3.2}*

Climate change is projected to increase displacement of people (*medium evidence, high agreement*). Populations that lack the resources for planned migration experience higher exposure to extreme weather events, particularly in developing countries with low income. Climate change can indirectly increase risks of violent conflicts by amplifying well-documented drivers of these conflicts such as poverty and economic shocks (*medium confidence*). *{2.3.2}*

SPM 2.4 Climate change beyond 2100, irreversibility and abrupt changes

Many aspects of climate change and associated impacts will continue for centuries, even if anthropogenic emissions of greenhouse gases are stopped. The risks of abrupt or irreversible changes increase as the magnitude of the warming increases. *{2.4}*

Warming will continue beyond 2100 under all RCP scenarios except RCP2.6. Surface temperatures will remain approximately constant at elevated levels for many centuries after a complete cessation of net anthropogenic CO_2 emissions. A large fraction of anthropogenic climate change resulting from CO_2 emissions is irreversible on a multi-century to millennial timescale, except in the case of a large net removal of CO_2 from the atmosphere over a sustained period. *{2.4, Figure 2.8}*

Stabilization of global average surface temperature does not imply stabilization for all aspects of the climate system. Shifting biomes, soil carbon, ice sheets, ocean temperatures and associated sea level rise all have their own intrinsic long timescales which will result in changes lasting hundreds to thousands of years after global surface temperature is stabilized. *{2.1, 2.4}*

There is *high confidence* that ocean acidification will increase for centuries if CO_2 emissions continue, and will strongly affect marine ecosystems. *{2.4}*

It is *virtually certain* that global mean sea level rise will continue for many centuries beyond 2100, with the amount of rise dependent on future emissions. The threshold for the loss of the Greenland ice sheet over a millennium or more, and an associated sea level rise of up to 7 m, is greater than about 1°C (*low confidence*) but less than about 4°C (*medium confidence*) of global warming with respect to pre-industrial temperatures. Abrupt and irreversible ice loss from the Antarctic ice sheet is possible, but current evidence and understanding is insufficient to make a quantitative assessment. *{2.4}*

Magnitudes and rates of climate change associated with medium- to high-emission scenarios pose an increased risk of abrupt and irreversible regional-scale change in the composition, structure and function of marine, terrestrial and freshwater ecosystems, including wetlands (*medium confidence*). A reduction in permafrost extent is *virtually certain* with continued rise in global temperatures. *{2.4}*

SPM 3. Future Pathways for Adaptation, Mitigation and Sustainable Development

Adaptation and mitigation are complementary strategies for reducing and managing the risks of climate change. Substantial emissions reductions over the next few decades can reduce climate risks in the 21st century and beyond, increase prospects for effective adaptation, reduce the costs and challenges of mitigation in the longer term and contribute to climate-resilient pathways for sustainable development. *{3.2, 3.3, 3.4}*

SPM 3.1 Foundations of decision-making about climate change

Effective decision-making to limit climate change and its effects can be informed by a wide range of analytical approaches for evaluating expected risks and benefits, recognizing the importance of governance, ethical dimensions, equity, value judgments, economic assessments and diverse perceptions and responses to risk and uncertainty. *{3.1}*

Sustainable development and equity provide a basis for assessing climate policies. Limiting the effects of climate change is necessary to achieve sustainable development and equity, including poverty eradication. Countries' past and future contributions to the accumulation of GHGs in the atmosphere are different, and countries also face varying challenges and circumstances and have different capacities to address mitigation and adaptation. Mitigation and adaptation raise issues of equity, justice and fairness. Many of those most vulnerable to climate change have contributed and contribute little to GHG emissions. Delaying mitigation shifts burdens from the present to the future, and insufficient adaptation responses to emerging impacts are already eroding the basis for sustainable development. Comprehensive strategies in response to climate change that are consistent with sustainable development take into account the co-benefits, adverse side effects and risks that may arise from both adaptation and mitigation options. *{3.1, 3.5, Box 3.4}*

The design of climate policy is influenced by how individuals and organizations perceive risks and uncertainties and take them into account. Methods of valuation from economic, social and ethical analysis are available to assist decision-making. These methods can take account of a wide range of possible impacts, including low-probability outcomes with large consequences. But they cannot identify a single best balance between mitigation, adaptation and residual climate impacts. *{3.1}*

Climate change has the characteristics of a collective action problem at the global scale, because most GHGs accumulate over time and mix globally, and emissions by any agent (e.g., individual, community, company, country) affect other agents. Effective mitigation will not be achieved if individual agents advance their own interests independently. Cooperative responses, including international cooperation, are therefore required to effectively mitigate GHG emissions and address other climate change issues. The effectiveness of adaptation can be enhanced through complementary actions across levels, including international cooperation. The evidence suggests that outcomes seen as equitable can lead to more effective cooperation. *{3.1}*

SPM 3.2 Climate change risks reduced by mitigation and adaptation

Without additional mitigation efforts beyond those in place today, and even with adaptation, warming by the end of the 21st century will lead to high to very high risk of severe, widespread and irreversible impacts globally (*high confidence*). Mitigation involves some level of co-benefits and of risks due to adverse side effects, but these risks do not involve the same possibility of severe, widespread and irreversible impacts as risks from climate change, increasing the benefits from near-term mitigation efforts. *{3.2, 3.4}*

Mitigation and adaptation are complementary approaches for reducing risks of climate change impacts over different timescales (*high confidence*). Mitigation, in the near term and through the century, can substantially reduce climate change

impacts in the latter decades of the 21st century and beyond. Benefits from adaptation can already be realized in addressing current risks, and can be realized in the future for addressing emerging risks. *{3.2, 4.5}*

Five Reasons For Concern (RFCs) aggregate climate change risks and illustrate the implications of warming and of adaptation limits for people, economies and ecosystems across sectors and regions. The five RFCs are associated with: (1) Unique and threatened systems, (2) Extreme weather events, (3) Distribution of impacts, (4) Global aggregate impacts, and (5) Large-scale singular events. In this report, the RFCs provide information relevant to Article 2 of UNFCCC. *{Box 2.4}*

Without additional mitigation efforts beyond those in place today, and even with adaptation, warming by the end of the 21st century will lead to high to very high risk of severe, widespread and irreversible impacts globally (*high confidence*) (Figure SPM.10). In most scenarios without additional mitigation efforts (those with 2100 atmospheric concentrations

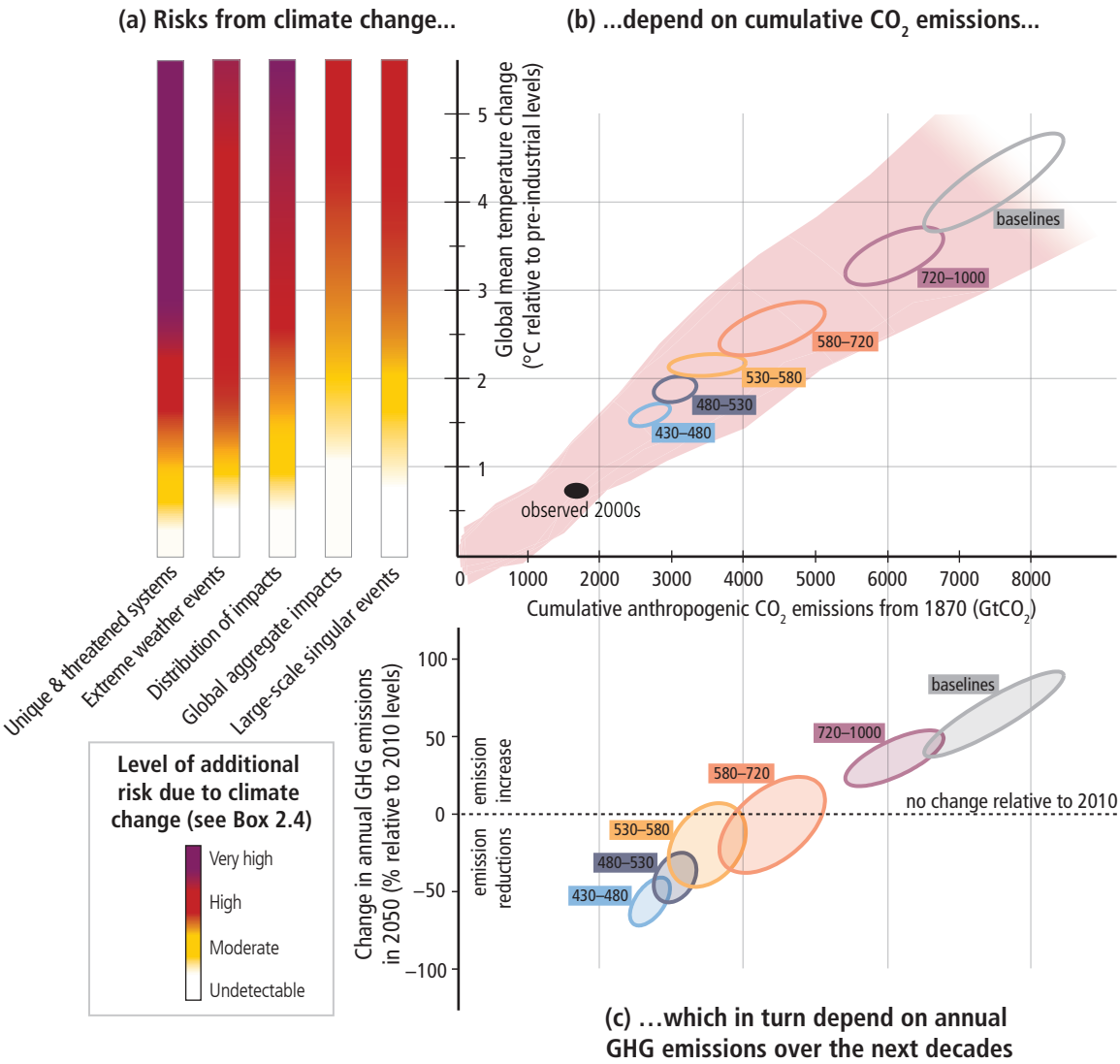


Figure SPM.10 | The relationship between risks from climate change, temperature change, cumulative carbon dioxide (CO_2) emissions and changes in annual greenhouse gas (GHG) emissions by 2050. Limiting risks across Reasons For Concern **(a)** would imply a limit for cumulative emissions of CO_2 **(b)** which would constrain annual GHG emissions over the next few decades **(c)**. **Panel a** reproduces the five Reasons For Concern *{Box 2.4}*. **Panel b** links temperature changes to cumulative CO_2 emissions (in $GtCO_2$) from 1870. They are based on Coupled Model Intercomparison Project Phase 5 (CMIP5) simulations (pink plume) and on a simple climate model (median climate response in 2100), for the baselines and five mitigation scenario categories (six ellipses). Details are provided in Figure SPM.5. **Panel c** shows the relationship between the cumulative CO_2 emissions (in $GtCO_2$) of the scenario categories and their associated change in annual GHG emissions by 2050, expressed in percentage change (in percent $GtCO_2$-eq per year) relative to 2010. The ellipses correspond to the same scenario categories as in Panel b, and are built with a similar method (see details in Figure SPM.5). *{Figure 3.1}*

>1000 ppm CO_2-eq), warming is *more likely than not* to exceed 4°C above pre-industrial levels by 2100 (Table SPM.1). The risks associated with temperatures at or above 4°C include substantial species extinction, global and regional food insecurity, consequential constraints on common human activities and limited potential for adaptation in some cases (*high confidence*). Some risks of climate change, such as risks to unique and threatened systems and risks associated with extreme weather events, are moderate to high at temperatures 1°C to 2°C above pre-industrial levels. *{2.3, Figure 2.5, 3.2, 3.4, Box 2.4, Table SPM.1}*

Substantial cuts in GHG emissions over the next few decades can substantially reduce risks of climate change by limiting warming in the second half of the 21st century and beyond. Cumulative emissions of CO_2 largely determine global mean surface warming by the late 21st century and beyond. Limiting risks across RFCs would imply a limit for cumulative emissions of CO_2. Such a limit would require that global net emissions of CO_2 eventually decrease to zero and would constrain annual emissions over the next few decades (Figure SPM.10) (*high confidence*). But some risks from climate damages are unavoidable, even with mitigation and adaptation. *{2.2.5, 3.2, 3.4}*

Mitigation involves some level of co-benefits and risks, but these risks do not involve the same possibility of severe, widespread and irreversible impacts as risks from climate change. Inertia in the economic and climate system and the possibility of irreversible impacts from climate change increase the benefits from near-term mitigation efforts (*high confidence*). Delays in additional mitigation or constraints on technological options increase the longer-term mitigation costs to hold climate change risks at a given level (Table SPM.2). *{3.2, 3.4}*

SPM 3.3 Characteristics of adaptation pathways

Adaptation can reduce the risks of climate change impacts, but there are limits to its effectiveness, especially with greater magnitudes and rates of climate change. Taking a longer-term perspective, in the context of sustainable development, increases the likelihood that more immediate adaptation actions will also enhance future options and preparedness. *{3.3}*

Adaptation can contribute to the well-being of populations, the security of assets and the maintenance of ecosystem goods, functions and services now and in the future. Adaptation is place- and context-specific (*high confidence*). A first step towards adaptation to future climate change is reducing vulnerability and exposure to present climate variability (*high confidence*). Integration of adaptation into planning, including policy design, and decision-making can promote synergies with development and disaster risk reduction. Building adaptive capacity is crucial for effective selection and implementation of adaptation options (*robust evidence, high agreement*). *{3.3}*

Adaptation planning and implementation can be enhanced through complementary actions across levels, from individuals to governments (*high confidence*). National governments can coordinate adaptation efforts of local and sub-national governments, for example by protecting vulnerable groups, by supporting economic diversification and by providing information, policy and legal frameworks and financial support (*robust evidence*, *high agreement*). Local government and the private sector are increasingly recognized as critical to progress in adaptation, given their roles in scaling up adaptation of communities, households and civil society and in managing risk information and financing (*medium evidence*, *high agreement*). *{3.3}*

Adaptation planning and implementation at all levels of governance are contingent on societal values, objectives and risk perceptions (*high confidence*). Recognition of diverse interests, circumstances, social-cultural contexts and expectations can benefit decision-making processes. Indigenous, local and traditional knowledge systems and practices, including indigenous peoples' holistic view of community and environment, are a major resource for adapting to climate change, but these have not been used consistently in existing adaptation efforts. Integrating such forms of knowledge with existing practices increases the effectiveness of adaptation. *{3.3}*

Constraints can interact to impede adaptation planning and implementation (*high confidence*). Common constraints on implementation arise from the following: limited financial and human resources; limited integration or coordination of governance; uncertainties about projected impacts; different perceptions of risks; competing values; absence of key adaptation leaders and advocates; and limited tools to monitor adaptation effectiveness. Another constraint includes insufficient research, monitoring, and observation and the finance to maintain them. *{3.3}*

Greater rates and magnitude of climate change increase the likelihood of exceeding adaptation limits (*high confidence*). Limits to adaptation emerge from the interaction among climate change and biophysical and/or socio-economic constraints. Further, poor planning or implementation, overemphasizing short-term outcomes or failing to sufficiently anticipate consequences can result in maladaptation, increasing the vulnerability or exposure of the target group in the future or the vulnerability of other people, places or sectors (*medium evidence, high agreement*). Underestimating the complexity of adaptation as a social process can create unrealistic expectations about achieving intended adaptation outcomes. *{3.3}*

Significant co-benefits, synergies and trade-offs exist between mitigation and adaptation and among different adaptation responses; interactions occur both within and across regions (*very high confidence*). Increasing efforts to mitigate and adapt to climate change imply an increasing complexity of interactions, particularly at the intersections among water, energy, land use and biodiversity, but tools to understand and manage these interactions remain limited. Examples of actions with co-benefits include (i) improved energy efficiency and cleaner energy sources, leading to reduced emissions of health-damaging, climate-altering air pollutants; (ii) reduced energy and water consumption in urban areas through greening cities and recycling water; (iii) sustainable agriculture and forestry; and (iv) protection of ecosystems for carbon storage and other ecosystem services. *{3.3}*

Transformations in economic, social, technological and political decisions and actions can enhance adaptation and promote sustainable development (*high confidence*). At the national level, transformation is considered most effective when it reflects a country's own visions and approaches to achieving sustainable development in accordance with its national circumstances and priorities. Restricting adaptation responses to incremental changes to existing systems and structures, without considering transformational change, may increase costs and losses and miss opportunities. Planning and implementation of transformational adaptation could reflect strengthened, altered or aligned paradigms and may place new and increased demands on governance structures to reconcile different goals and visions for the future and to address possible equity and ethical implications. Adaptation pathways are enhanced by iterative learning, deliberative processes and innovation. *{3.3}*

SPM 3.4 Characteristics of mitigation pathways

There are multiple mitigation pathways that are *likely* to limit warming to below 2°C relative to pre-industrial levels. These pathways would require substantial emissions reductions over the next few decades and near zero emissions of CO_2 and other long-lived greenhouse gases by the end of the century. Implementing such reductions poses substantial technological, economic, social and institutional challenges, which increase with delays in additional mitigation and if key technologies are not available. Limiting warming to lower or higher levels involves similar challenges but on different timescales. *{3.4}*

Without additional efforts to reduce GHG emissions beyond those in place today, global emissions growth is expected to persist, driven by growth in global population and economic activities. Global mean surface temperature increases in 2100 in baseline scenarios—those without additional mitigation—range from 3.7°C to 4.8°C above the average for 1850–1900 for a median climate response. They range from 2.5°C to 7.8°C when including climate uncertainty (5th to 95th percentile range) (*high confidence*). *{3.4}*

Emissions scenarios leading to CO_2-equivalent concentrations in 2100 of about 450 ppm or lower are *likely* to maintain warming below 2°C over the 21st century relative to pre-industrial levels[15]. These scenarios are characterized by 40 to 70% global anthropogenic GHG emissions reductions by 2050 compared to 2010[16], and emissions levels near zero or below in 2100. Mitigation scenarios reaching concentration levels of about 500 ppm CO_2-eq by 2100 are *more likely than not* to limit temperature change to less than 2°C, unless they temporarily overshoot concentration levels of roughly 530 ppm CO_2-eq

[15] For comparison, the CO_2-eq concentration in 2011 is estimated to be 430 ppm (uncertainty range 340 to 520 ppm)

[16] This range differs from the range provided for a similar concentration category in the AR4 (50 to 85% lower than 2000 for CO_2 only). Reasons for this difference include that this report has assessed a substantially larger number of scenarios than in the AR4 and looks at all GHGs. In addition, a large proportion of the new scenarios include Carbon Dioxide Removal (CDR) technologies (see below). Other factors include the use of 2100 concentration levels instead of stabilization levels and the shift in reference year from 2000 to 2010.

before 2100, in which case they are *about as likely as not* to achieve that goal. In these 500 ppm CO_2-eq scenarios, global 2050 emissions levels are 25 to 55% lower than in 2010. Scenarios with higher emissions in 2050 are characterized by a greater reliance on Carbon Dioxide Removal (CDR) technologies beyond mid-century (and vice versa). Trajectories that are *likely* to limit warming to 3°C relative to pre-industrial levels reduce emissions less rapidly than those limiting warming to 2°C. A limited number of studies provide scenarios that are *more likely than not* to limit warming to 1.5°C by 2100; these scenarios are characterized by concentrations below 430 ppm CO_2-eq by 2100 and 2050 emission reduction between 70% and 95% below 2010. For a comprehensive overview of the characteristics of emissions scenarios, their CO_2-equivalent concentrations and their likelihood to keep warming to below a range of temperature levels, see Figure SPM.11 and Table SPM.1. *{3.4}*

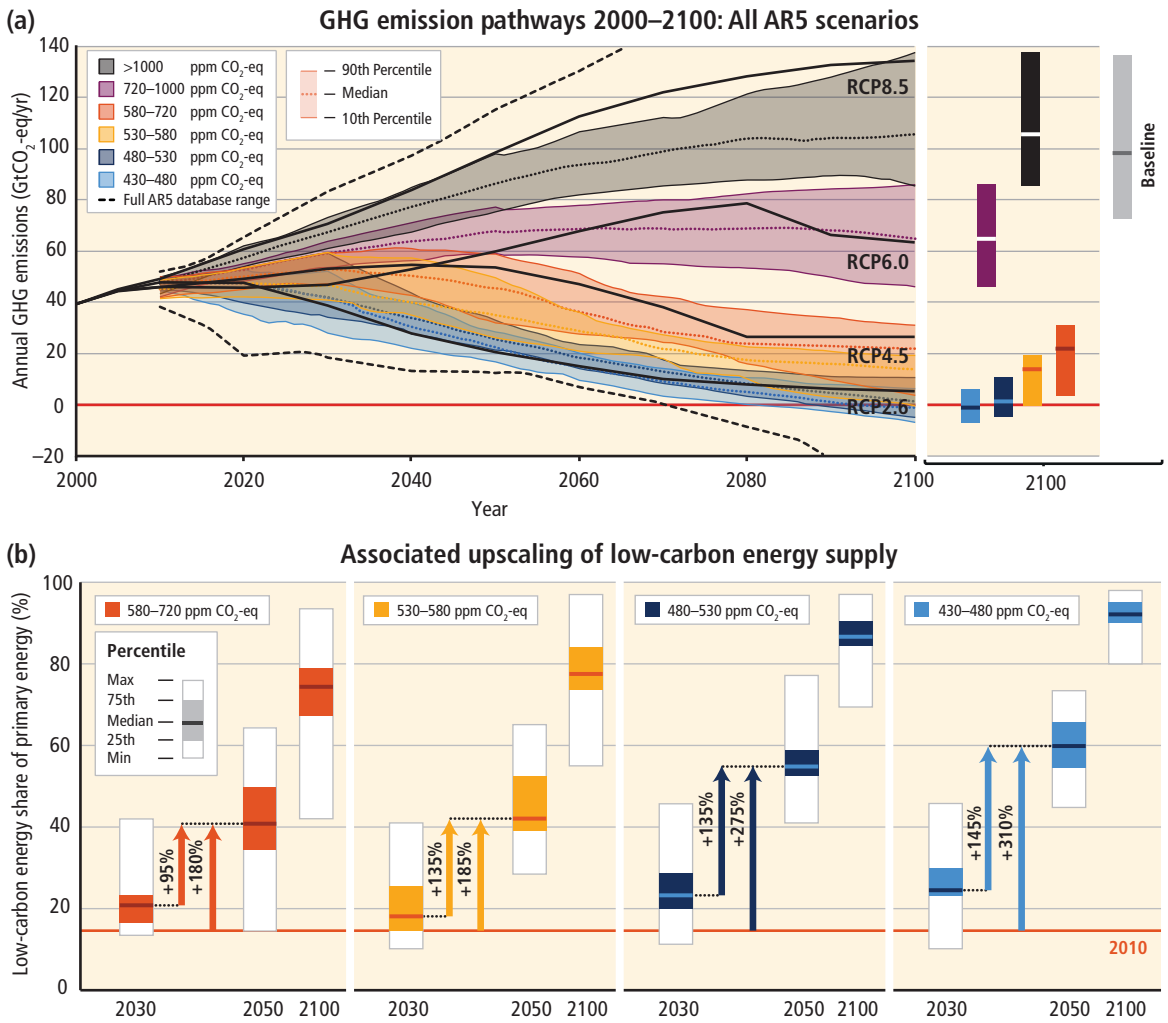


Figure SPM.11 | Global greenhouse gas emissions (gigatonne of CO_2-equivalent per year, $GtCO_2$-eq/yr) in baseline and mitigation scenarios for different long-term concentration levels **(a)** and associated upscaling requirements of low-carbon energy (% of primary energy) for 2030, 2050 and 2100 compared to 2010 levels in mitigation scenarios **(b)**. *{Figure 3.2}*

Table SPM.1 | Key characteristics of the scenarios collected and assessed for WGIII AR5. For all parameters the 10th to 90th percentile of the scenarios is shown [a]. *{Table 3.1}*

CO_2-eq Concentrations in 2100 (ppm CO_2-eq) [f] Category label (conc. range)	Subcategories	Relative position of the RCPs [d]	Change in CO_2-eq emissions compared to 2010 (in %) [c]		Likelihood of staying below a specific temperature level over the 21st century (relative to 1850–1900) [d, e]			
			2050	2100	1.5°C	2°C	3°C	4°C
<430	Only a limited number of individual model studies have explored levels below 430 ppm CO_2-eq [j]							
450 (430 to 480)	Total range [a, g]	RCP2.6	–72 to –41	–118 to –78	*More unlikely than likely*	*Likely*	*Likely*	*Likely*
500 (480 to 530)	No overshoot of 530 ppm CO_2-eq		–57 to –42	–107 to –73	*Unlikely*	*More likely than not*		
	Overshoot of 530 ppm CO_2-eq		–55 to –25	–114 to –90		*About as likely as not*		
550 (530 to 580)	No overshoot of 580 ppm CO_2-eq		–47 to –19	–81 to –59		*More unlikely than likely* [i]		
	Overshoot of 580 ppm CO_2-eq		–16 to 7	–183 to –86				
(580 to 650)	Total range	RCP4.5	–38 to 24	–134 to –50				
(650 to 720)	Total range		–11 to 17	–54 to –21		*Unlikely*	*More likely than not*	
(720 to 1000) [b]	Total range	RCP6.0	18 to 54	–7 to 72	*Unlikely* [h]		*More unlikely than likely*	
>1000 [b]	Total range	RCP8.5	52 to 95	74 to 178		*Unlikely* [h]	*Unlikely*	*More unlikely than likely*

Notes:

[a] The 'total range' for the 430 to 480 ppm CO_2-eq concentrations scenarios corresponds to the range of the 10th to 90th percentile of the subcategory of these scenarios shown in Table 6.3 of the Working Group III Report.

[b] Baseline scenarios fall into the >1000 and 720 to 1000 ppm CO_2-eq categories. The latter category also includes mitigation scenarios. The baseline scenarios in the latter category reach a temperature change of 2.5°C to 5.8°C above the average for 1850–1900 in 2100. Together with the baseline scenarios in the >1000 ppm CO_2-eq category, this leads to an overall 2100 temperature range of 2.5°C to 7.8°C (range based on median climate response: 3.7°C to 4.8°C) for baseline scenarios across both concentration categories.

[c] The global 2010 emissions are 31% above the 1990 emissions (consistent with the historic greenhouse gas emission estimates presented in this report). CO_2-eq emissions include the basket of Kyoto gases (carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O) as well as fluorinated gases).

[d] The assessment here involves a large number of scenarios published in the scientific literature and is thus not limited to the Representative Concentration Pathways (RCPs). To evaluate the CO_2-eq concentration and climate implications of these scenarios, the Model for the Assessment of Greenhouse Gas Induced Climate Change (MAGICC) was used in a probabilistic mode. For a comparison between MAGICC model results and the outcomes of the models used in WGI, see WGI 12.4.1.2, 12.4.8 and WGIII 6.3.2.6.

[e] The assessment in this table is based on the probabilities calculated for the full ensemble of scenarios in WGIII AR5 using MAGICC and the assessment in WGI of the uncertainty of the temperature projections not covered by climate models. The statements are therefore consistent with the statements in WGI, which are based on the Coupled Model Intercomparison Project Phase 5 (CMIP5) runs of the RCPs and the assessed uncertainties. Hence, the likelihood statements reflect different lines of evidence from both WGs. This WGI method was also applied for scenarios with intermediate concentration levels where no CMIP5 runs are available. The likelihood statements are indicative only *{WGIII 6.3}* and follow broadly the terms used by the WGI SPM for temperature projections: likely 66–100%, more likely than not >50–100%, about as likely as not 33–66%, and unlikely 0–33%. In addition the term more unlikely than likely 0–<50% is used.

[f] The CO_2-equivalent concentration (see Glossary) is calculated on the basis of the total forcing from a simple carbon cycle/climate model, MAGICC. The CO_2-equivalent concentration in 2011 is estimated to be 430 ppm (uncertainty range 340 to 520 ppm). This is based on the assessment of total anthropogenic radiative forcing for 2011 relative to 1750 in WGI, i.e., 2.3 W/m^2, uncertainty range 1.1 to 3.3 W/m^2.

[g] The vast majority of scenarios in this category overshoot the category boundary of 480 ppm CO_2-eq concentration.

[h] For scenarios in this category, no CMIP5 run or MAGICC realization stays below the respective temperature level. Still, an *unlikely* assignment is given to reflect uncertainties that may not be reflected by the current climate models.

[i] Scenarios in the 580 to 650 ppm CO_2-eq category include both overshoot scenarios and scenarios that do not exceed the concentration level at the high end of the category (e.g., RCP4.5). The latter type of scenarios, in general, have an assessed probability of *more unlikely than likely* to stay below the 2°C temperature level, while the former are mostly assessed to have an *unlikely* probability of staying below this level.

[j] In these scenarios, global CO_2-eq emissions in 2050 are between 70 to 95% below 2010 emissions, and they are between 110 to 120% below 2010 emissions in 2100.

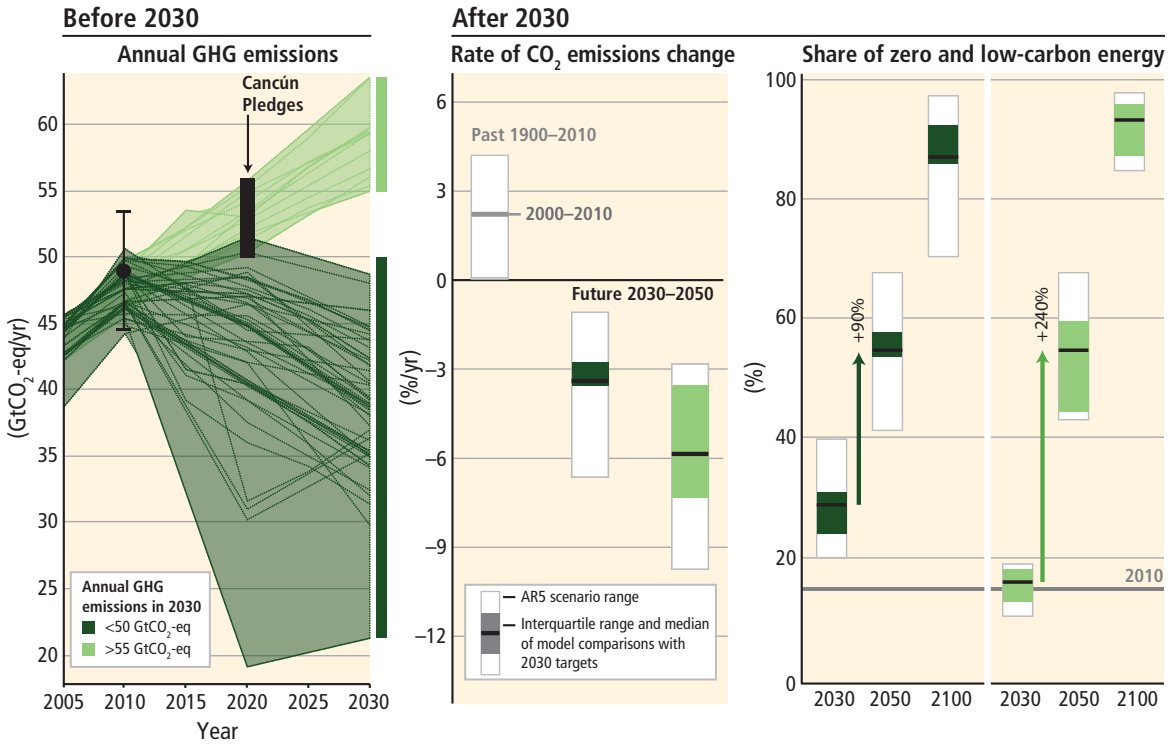


Figure SPM.12 | The implications of different 2030 greenhouse gas (GHG) emissions levels for the rate of carbon dioxide (CO_2) emissions reductions and low-carbon energy upscaling in mitigation scenarios that are at least *about as likely as not* to keep warming throughout the 21st century below 2°C relative to pre-industrial levels (2100 CO_2-equivalent concentrations of 430 to 530 ppm). The scenarios are grouped according to different emissions levels by 2030 (coloured in different shades of green). The left panel shows the pathways of GHG emissions (gigatonne of CO_2-equivalent per year, $GtCO_2$-eq/yr) leading to these 2030 levels. The black dot with whiskers gives historic GHG emission levels and associated uncertainties in 2010 as reported in Figure SPM.2. The black bar shows the estimated uncertainty range of GHG emissions implied by the Cancún Pledges. The middle panel denotes the average annual CO_2 emissions reduction rates for the period 2030–2050. It compares the median and interquartile range across scenarios from recent inter-model comparisons with explicit 2030 interim goals to the range of scenarios in the Scenario Database for WGIII AR5. Annual rates of historical emissions change (sustained over a period of 20 years) and the average annual CO_2 emission change between 2000 and 2010 are shown as well. The arrows in the right panel show the magnitude of zero and low-carbon energy supply upscaling from 2030 to 2050 subject to different 2030 GHG emissions levels. Zero- and low-carbon energy supply includes renewables, nuclear energy and fossil energy with carbon dioxide capture and storage (CCS) or bioenergy with CCS (BECCS). [Note: Only scenarios that apply the full, unconstrained mitigation technology portfolio of the underlying models (default technology assumption) are shown. Scenarios with large net negative global emissions (>20 $GtCO_2$-eq/yr), scenarios with exogenous carbon price assumptions and scenarios with 2010 emissions significantly outside the historical range are excluded.] *{Figure 3.3}*

Mitigation scenarios reaching about 450 ppm CO_2-eq in 2100 (consistent with a *likely* chance to keep warming below 2°C relative to pre-industrial levels) typically involve temporary overshoot[17] of atmospheric concentrations, as do many scenarios reaching about 500 ppm CO_2-eq to about 550 ppm CO_2-eq in 2100 (Table SPM.1). Depending on the level of overshoot, overshoot scenarios typically rely on the availability and widespread deployment of bioenergy with carbon dioxide capture and storage (BECCS) and afforestation in the second half of the century. The availability and scale of these and other CDR technologies and methods are uncertain and CDR technologies are, to varying degrees, associated with challenges and risks[18]. CDR is also prevalent in many scenarios without overshoot to compensate for residual emissions from sectors where mitigation is more expensive (*high confidence*). *{3.4, Box 3.3}*

Reducing emissions of non-CO_2 agents can be an important element of mitigation strategies. All current GHG emissions and other forcing agents affect the rate and magnitude of climate change over the next few decades, although long-term warming is mainly driven by CO_2 emissions. Emissions of non-CO_2 forcers are often expressed as 'CO_2-equivalent emissions', but the choice of metric to calculate these emissions, and the implications for the emphasis and timing of abatement of the various climate forcers, depends on application and policy context and contains value judgments. *{3.4, Box 3.2}*

[17] In concentration 'overshoot' scenarios, concentrations peak during the century and then decline.

[18] CDR methods have biogeochemical and technological limitations to their potential on the global scale. There is insufficient knowledge to quantify how much CO_2 emissions could be partially offset by CDR on a century timescale. CDR methods may carry side effects and long-term consequences on a global scale.

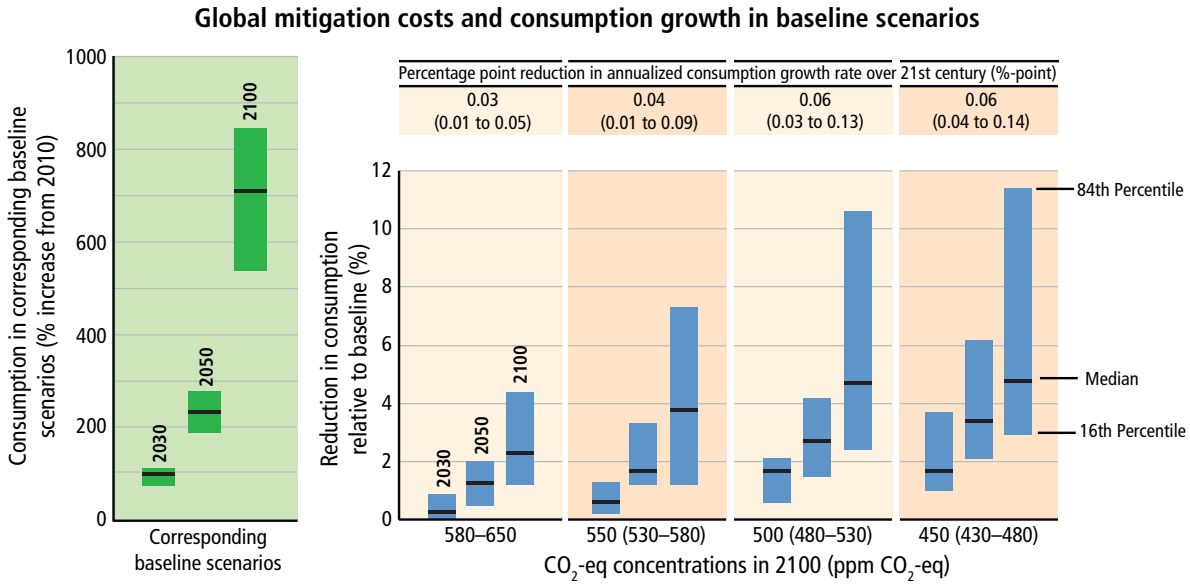


Figure SPM.13 | Global mitigation costs in cost-effective scenarios at different atmospheric concentrations levels in 2100. Cost-effective scenarios assume immediate mitigation in all countries and a single global carbon price, and impose no additional limitations on technology relative to the models' default technology assumptions. Consumption losses are shown relative to a baseline development without climate policy (left panel). The table at the top shows percentage points of annualized consumption growth reductions relative to consumption growth in the baseline of 1.6 to 3% per year (e.g., if the reduction is 0.06 percentage points per year due to mitigation, and baseline growth is 2.0% per year, then the growth rate with mitigation would be 1.94% per year). Cost estimates shown in this table do not consider the benefits of reduced climate change or co-benefits and adverse side effects of mitigation. Estimates at the high end of these cost ranges are from models that are relatively inflexible to achieve the deep emissions reductions required in the long run to meet these goals and/or include assumptions about market imperfections that would raise costs. *{Figure 3.4}*

Delaying additional mitigation to 2030 will substantially increase the challenges associated with limiting warming over the 21st century to below 2°C relative to pre-industrial levels. It will require substantially higher rates of emissions reductions from 2030 to 2050; a much more rapid scale-up of low-carbon energy over this period; a larger reliance on CDR in the long term; and higher transitional and long-term economic impacts. Estimated global emissions levels in 2020 based on the Cancún Pledges are not consistent with cost-effective mitigation trajectories that are at least *about as likely as not* to limit warming to below 2°C relative to pre-industrial levels, but they do not preclude the option to meet this goal (*high confidence*) (Figure SPM.12, Table SPM.2). *{3.4}*

Estimates of the aggregate economic costs of mitigation vary widely depending on methodologies and assumptions, but increase with the stringency of mitigation. Scenarios in which all countries of the world begin mitigation immediately, in which there is a single global carbon price, and in which all key technologies are available have been used as a cost-effective benchmark for estimating macro-economic mitigation costs (Figure SPM.13). Under these assumptions mitigation scenarios that are *likely* to limit warming to below 2°C through the 21st century relative to pre-industrial levels entail losses in global consumption—not including benefits of reduced climate change as well as co-benefits and adverse side effects of mitigation—of 1 to 4% (median: 1.7%) in 2030, 2 to 6% (median: 3.4%) in 2050 and 3 to 11% (median: 4.8%) in 2100 relative to consumption in baseline scenarios that grows anywhere from 300% to more than 900% over the century (Figure SPM.13). These numbers correspond to an annualized reduction of consumption growth by 0.04 to 0.14 (median: 0.06) percentage points over the century relative to annualized consumption growth in the baseline that is between 1.6 and 3% per year (*high confidence*). *{3.4}*

In the absence or under limited availability of mitigation technologies (such as bioenergy, CCS and their combination BECCS, nuclear, wind/solar), mitigation costs can increase substantially depending on the technology considered. Delaying additional mitigation increases mitigation costs in the medium to long term. Many models could not limit *likely* warming to below 2°C over the 21st century relative to pre-industrial levels if additional mitigation is considerably delayed. Many models could not limit *likely* warming to below 2°C if bioenergy, CCS and their combination (BECCS) are limited (*high confidence*) (Table SPM.2). *{3.4}*

Table SPM.2 | Increase in global mitigation costs due to either limited availability of specific technologies or delays in additional mitigation [a] relative to cost-effective scenarios [b]. The increase in costs is given for the median estimate and the 16th to 84th percentile range of the scenarios (in parentheses) [c]. In addition, the sample size of each scenario set is provided in the coloured symbols. The colours of the symbols indicate the fraction of models from systematic model comparison exercises that could successfully reach the targeted concentration level. *{Table 3.2}*

Mitigation cost increases in scenarios with limited availability of technologies [d] *[% increase in total discounted [e] mitigation costs (2015–2100) relative to default technology assumptions]*					**Mitigation cost increases due to delayed additional mitigation until 2030** *[% increase in mitigation costs relative to immediate mitigation]*	
2100 concentrations (ppm CO_2-eq)	no CCS	nuclear phase out	limited solar/wind	limited bioenergy	medium term costs (2030–2050)	long term costs (2050–2100)
450 (430 to 480)	138% (29 to 297%) 4	7% (4 to 18%) 8	6% (2 to 29%) 8	64% (44 to 78%) 8	44% (2 to 78%) 29	37% (16 to 82%) 29
500 (480 to 530)	not available (n.a.)	n.a.	n.a.	n.a.		
550 (530 to 580)	39% (18 to 78%) 11	13% (2 to 23%) 10	8% (5 to 15%) 10	18% (4 to 66%) 12	15% (3 to 32%)	16% (5 to 24%)
580 to 650	n.a.	n.a.	n.a.	n.a.		

Symbol legend—fraction of models successful in producing scenarios (numbers indicate the number of successful models)

: all models successful

: between 80 and 100% of models successful

: between 50 and 80% of models successful

: less than 50% of models successful

Notes:

[a] Delayed mitigation scenarios are associated with greenhouse gas emission of more than 55 $GtCO_2$-eq in 2030, and the increase in mitigation costs is measured relative to cost-effective mitigation scenarios for the same long-term concentration level.

[b] Cost-effective scenarios assume immediate mitigation in all countries and a single global carbon price, and impose no additional limitations on technology relative to the models' default technology assumptions.

[c] The range is determined by the central scenarios encompassing the 16th to 84th percentile range of the scenario set. Only scenarios with a time horizon until 2100 are included. Some models that are included in the cost ranges for concentration levels above 530 ppm CO_2-eq in 2100 could not produce associated scenarios for concentration levels below 530 ppm CO_2-eq in 2100 with assumptions about limited availability of technologies and/or delayed additional mitigation.

[d] No CCS: carbon dioxide capture and storage is not included in these scenarios. Nuclear phase out: no addition of nuclear power plants beyond those under construction, and operation of existing plants until the end of their lifetime. Limited Solar/Wind: a maximum of 20% global electricity generation from solar and wind power in any year of these scenarios. Limited Bioenergy: a maximum of 100 EJ/yr modern bioenergy supply globally (modern bioenergy used for heat, power, combinations and industry was around 18 EJ/yr in 2008). EJ = Exajoule = 10^{18} Joule.

[e] Percentage increase of net present value of consumption losses in percent of baseline consumption (for scenarios from general equilibrium models) and abatement costs in percent of baseline gross domestic product (GDP, for scenarios from partial equilibrium models) for the period 2015–2100, discounted at 5% per year.

Mitigation scenarios reaching about 450 or 500 ppm CO_2-eq by 2100 show reduced costs for achieving air quality and energy security objectives, with significant co-benefits for human health, ecosystem impacts and sufficiency of resources and resilience of the energy system. *{4.4.2.2}*

Mitigation policy could devalue fossil fuel assets and reduce revenues for fossil fuel exporters, but differences between regions and fuels exist (*high confidence*). Most mitigation scenarios are associated with reduced revenues from coal and oil trade for major exporters (*high confidence*). The availability of CCS would reduce the adverse effects of mitigation on the value of fossil fuel assets (*medium confidence*). *{4.4.2.2}*

Solar Radiation Management (SRM) involves large-scale methods that seek to reduce the amount of absorbed solar energy in the climate system. SRM is untested and is not included in any of the mitigation scenarios. If it were deployed, SRM would

entail numerous uncertainties, side effects, risks and shortcomings and has particular governance and ethical implications. SRM would not reduce ocean acidification. If it were terminated, there is *high confidence* that surface temperatures would rise very rapidly impacting ecosystems susceptible to rapid rates of change. *{Box 3.3}*

SPM 4. Adaptation and Mitigation

Many adaptation and mitigation options can help address climate change, but no single option is sufficient by itself. Effective implementation depends on policies and cooperation at all scales and can be enhanced through integrated responses that link adaptation and mitigation with other societal objectives. *{4}*

SPM 4.1 Common enabling factors and constraints for adaptation and mitigation responses

Adaptation and mitigation responses are underpinned by common enabling factors. These include effective institutions and governance, innovation and investments in environmentally sound technologies and infrastructure, sustainable livelihoods and behavioural and lifestyle choices. *{4.1}*

Inertia in many aspects of the socio-economic system constrains adaptation and mitigation options (*medium evidence, high agreement*). Innovation and investments in environmentally sound infrastructure and technologies can reduce GHG emissions and enhance resilience to climate change (*very high confidence*). *{4.1}*

Vulnerability to climate change, GHG emissions and the capacity for adaptation and mitigation are strongly influenced by livelihoods, lifestyles, behaviour and culture (*medium evidence, medium agreement*). Also, the social acceptability and/or effectiveness of climate policies are influenced by the extent to which they incentivize or depend on regionally appropriate changes in lifestyles or behaviours. *{4.1}*

For many regions and sectors, enhanced capacities to mitigate and adapt are part of the foundation essential for managing climate change risks (*high confidence*). Improving institutions as well as coordination and cooperation in governance can help overcome regional constraints associated with mitigation, adaptation and disaster risk reduction (*very high confidence*). *{4.1}*

SPM 4.2 Response options for adaptation

Adaptation options exist in all sectors, but their context for implementation and potential to reduce climate-related risks differs across sectors and regions. Some adaptation responses involve significant co-benefits, synergies and trade-offs. Increasing climate change will increase challenges for many adaptation options. *{4.2}*

Adaptation experience is accumulating across regions in the public and private sectors and within communities. There is increasing recognition of the value of social (including local and indigenous), institutional, and ecosystem-based measures and of the extent of constraints to adaptation. Adaptation is becoming embedded in some planning processes, with more limited implementation of responses (*high confidence*). *{1.6, 4.2, 4.4.2.1}*

The need for adaptation along with associated challenges is expected to increase with climate change (*very high confidence*). Adaptation options exist in all sectors and regions, with diverse potential and approaches depending on their context in vulnerability reduction, disaster risk management or proactive adaptation planning (Table SPM.3). Effective strategies and actions consider the potential for co-benefits and opportunities within wider strategic goals and development plans. *{4.2}*

Table SPM.3 | Approaches for managing the risks of climate change through adaptation. These approaches should be considered overlapping rather than discrete, and they are often pursued simultaneously. Examples are presented in no specific order and can be relevant to more than one category. *{Table 4.2}*

Overlapping Approaches	Category	Examples
Vulnerability & Exposure Reduction through development, planning & practices including many low-regrets measures	Human development	Improved access to education, nutrition, health facilities, energy, safe housing & settlement structures, & social support structures; Reduced gender inequality & marginalization in other forms.
	Poverty alleviation	Improved access to & control of local resources; Land tenure; Disaster risk reduction; Social safety nets & social protection; Insurance schemes.
	Livelihood security	Income, asset & livelihood diversification; Improved infrastructure; Access to technology & decision-making fora; Increased decision-making power; Changed cropping, livestock & aquaculture practices; Reliance on social networks.
	Disaster risk management	Early warning systems; Hazard & vulnerability mapping; Diversifying water resources; Improved drainage; Flood & cyclone shelters; Building codes & practices; Storm & wastewater management; Transport & road infrastructure improvements.
	Ecosystem management	Maintaining wetlands & urban green spaces; Coastal afforestation; Watershed & reservoir management; Reduction of other stressors on ecosystems & of habitat fragmentation; Maintenance of genetic diversity; Manipulation of disturbance regimes; Community-based natural resource management.
	Spatial or land-use planning	Provisioning of adequate housing, infrastructure & services; Managing development in flood prone & other high risk areas; Urban planning & upgrading programs; Land zoning laws; Easements; Protected areas.
Adaptation including incremental & transformational adjustments	Structural/physical	***Engineered & built-environment options***: Sea walls & coastal protection structures; Flood levees; Water storage; Improved drainage; Flood & cyclone shelters; Building codes & practices; Storm & wastewater management; Transport & road infrastructure improvements; Floating houses; Power plant & electricity grid adjustments.
		Technological options: New crop & animal varieties; Indigenous, traditional & local knowledge, technologies & methods; Efficient irrigation; Water-saving technologies; Desalinisation; Conservation agriculture; Food storage & preservation facilities; Hazard & vulnerability mapping & monitoring; Early warning systems; Building insulation; Mechanical & passive cooling; Technology development, transfer & diffusion.
		Ecosystem-based options: Ecological restoration; Soil conservation; Afforestation & reforestation; Mangrove conservation & replanting; Green infrastructure (e.g., shade trees, green roofs); Controlling overfishing; Fisheries co-management; Assisted species migration & dispersal; Ecological corridors; Seed banks, gene banks & other *ex situ* conservation; Community-based natural resource management.
		Services: Social safety nets & social protection; Food banks & distribution of food surplus; Municipal services including water & sanitation; Vaccination programs; Essential public health services; Enhanced emergency medical services.
	Institutional	***Economic options***: Financial incentives; Insurance; Catastrophe bonds; Payments for ecosystem services; Pricing water to encourage universal provision and careful use; Microfinance; Disaster contingency funds; Cash transfers; Public-private partnerships.
		Laws & regulations: Land zoning laws; Building standards & practices; Easements; Water regulations & agreements; Laws to support disaster risk reduction; Laws to encourage insurance purchasing; Defined property rights & land tenure security; Protected areas; Fishing quotas; Patent pools & technology transfer.
		National & government policies & programs: National & regional adaptation plans including mainstreaming; Sub-national & local adaptation plans; Economic diversification; Urban upgrading programs; Municipal water management programs; Disaster planning & preparedness; Integrated water resource management; Integrated coastal zone management; Ecosystem-based management; Community-based adaptation.
	Social	***Educational options***: Awareness raising & integrating into education; Gender equity in education; Extension services; Sharing indigenous, traditional & local knowledge; Participatory action research & social learning; Knowledge-sharing & learning platforms.
		Informational options: Hazard & vulnerability mapping; Early warning & response systems; Systematic monitoring & remote sensing; Climate services; Use of indigenous climate observations; Participatory scenario development; Integrated assessments.
		Behavioural options: Household preparation & evacuation planning; Migration; Soil & water conservation; Storm drain clearance; Livelihood diversification; Changed cropping, livestock & aquaculture practices; Reliance on social networks.
Transformation	Spheres of change	***Practical***: Social & technical innovations, behavioural shifts, or institutional & managerial changes that produce substantial shifts in outcomes.
		Political: Political, social, cultural & ecological decisions & actions consistent with reducing vulnerability & risk & supporting adaptation, mitigation & sustainable development.
		Personal: Individual & collective assumptions, beliefs, values & worldviews influencing climate-change responses.

SPM 4.3 Response options for mitigation

Mitigation options are available in every major sector. Mitigation can be more cost-effective if using an integrated approach that combines measures to reduce energy use and the greenhouse gas intensity of end-use sectors, decarbonize energy supply, reduce net emissions and enhance carbon sinks in land-based sectors. *{4.3}*

Well-designed systemic and cross-sectoral mitigation strategies are more cost-effective in cutting emissions than a focus on individual technologies and sectors, with efforts in one sector affecting the need for mitigation in others (*medium confidence*). Mitigation measures intersect with other societal goals, creating the possibility of co-benefits or adverse side effects. These intersections, if well-managed, can strengthen the basis for undertaking climate action. *{4.3}*

Emissions ranges for baseline scenarios and mitigation scenarios that limit CO_2-equivalent concentrations to low levels (about 450 ppm CO_2-eq, *likely* to limit warming to 2°C above pre-industrial levels) are shown for different sectors and gases in Figure SPM.14. Key measures to achieve such mitigation goals include decarbonizing (i.e., reducing the carbon intensity of) electricity generation (*medium evidence, high agreement*) as well as efficiency enhancements and behavioural changes, in order to reduce energy demand compared to baseline scenarios without compromising development (*robust evidence, high agreement*). In scenarios reaching 450 ppm CO_2-eq concentrations by 2100, global CO_2 emissions from the energy supply sector are projected to decline over the next decade and are characterized by reductions of 90% or more below 2010 levels between 2040 and 2070. In the majority of low-concentration stabilization scenarios (about 450 to about 500 ppm CO_2-eq, at least *about as likely as not* to limit warming to 2°C above pre-industrial levels), the share of low-carbon electricity supply (comprising renewable energy (RE), nuclear and carbon dioxide capture and storage (CCS) including bioenergy with carbon dioxide capture and storage (BECCS)) increases from the current share of approximately 30% to more than 80% by 2050, and fossil fuel power generation without CCS is phased out almost entirely by 2100. *{4.3}*

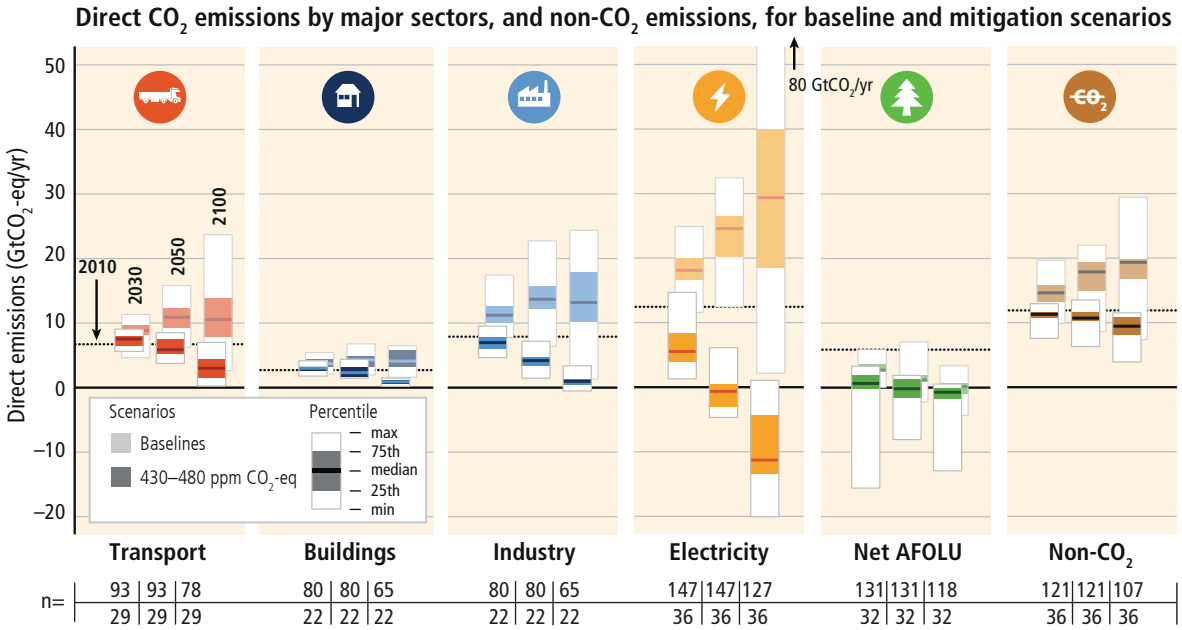


Figure SPM.14 | Carbon dioxide (CO_2) emissions by sector and total non-CO_2 greenhouse gases (Kyoto gases) across sectors in baseline (faded bars) and mitigation scenarios (solid colour bars) that reach about 450 (430 to 480) ppm CO_2-eq concentrations in 2100 (*likely* to limit warming to 2°C above pre-industrial levels). Mitigation in the end-use sectors leads also to indirect emissions reductions in the upstream energy supply sector. Direct emissions of the end-use sectors thus do not include the emission reduction potential at the supply-side due to, for example, reduced electricity demand. The numbers at the bottom of the graphs refer to the number of scenarios included in the range (upper row: baseline scenarios; lower row: mitigation scenarios), which differs across sectors and time due to different sectoral resolution and time horizon of models. Emissions ranges for mitigation scenarios include the full portfolio of mitigation options; many models cannot reach 450 ppm CO_2-eq concentration by 2100 in the absence of carbon dioxide capture and storage (CCS). Negative emissions in the electricity sector are due to the application of bioenergy with carbon dioxide capture and storage (BECCS). 'Net' agriculture, forestry and other land use (AFOLU) emissions consider afforestation, reforestation as well as deforestation activities. *{4.3, Figure 4.1}*

Near-term reductions in energy demand are an important element of cost-effective mitigation strategies, provide more flexibility for reducing carbon intensity in the energy supply sector, hedge against related supply-side risks, avoid lock-in to carbon-intensive infrastructures, and are associated with important co-benefits. The most cost-effective mitigation options in forestry are afforestation, sustainable forest management and reducing deforestation, with large differences in their relative importance across regions; and in agriculture, cropland management, grazing land management and restoration of organic soils (*medium evidence, high agreement*). *{4.3, Figures 4.1, 4.2, Table 4.3}*

Behaviour, lifestyle and culture have a considerable influence on energy use and associated emissions, with high mitigation potential in some sectors, in particular when complementing technological and structural change (*medium evidence, medium agreement*). Emissions can be substantially lowered through changes in consumption patterns, adoption of energy savings measures, dietary change and reduction in food wastes. *{4.1, 4.3}*

SPM 4.4 Policy approaches for adaptation and mitigation, technology and finance

Effective adaptation and mitigation responses will depend on policies and measures across multiple scales: international, regional, national and sub-national. Policies across all scales supporting technology development, diffusion and transfer, as well as finance for responses to climate change, can complement and enhance the effectiveness of policies that directly promote adaptation and mitigation. *{4.4}*

International cooperation is critical for effective mitigation, even though mitigation can also have local co-benefits. Adaptation focuses primarily on local to national scale outcomes, but its effectiveness can be enhanced through coordination across governance scales, including international cooperation: *{3.1, 4.4.1}*

- The United Nations Framework Convention on Climate Change (UNFCCC) is the main multilateral forum focused on addressing climate change, with nearly universal participation. Other institutions organized at different levels of governance have resulted in diversifying international climate change cooperation. *{4.4.1}*

- The Kyoto Protocol offers lessons towards achieving the ultimate objective of the UNFCCC, particularly with respect to participation, implementation, flexibility mechanisms and environmental effectiveness (*medium evidence, low agreement*). *{4.4.1}*

- Policy linkages among regional, national and sub-national climate policies offer potential climate change mitigation benefits (*medium evidence, medium agreement*). Potential advantages include lower mitigation costs, decreased emission leakage and increased market liquidity. *{4.4.1}*

- International cooperation for supporting adaptation planning and implementation has received less attention historically than mitigation but is increasing and has assisted in the creation of adaptation strategies, plans and actions at the national, sub-national and local level (*high confidence*). *{4.4.1}*

There has been a considerable increase in national and sub-national plans and strategies on both adaptation and mitigation since the AR4, with an increased focus on policies designed to integrate multiple objectives, increase co-benefits and reduce adverse side effects (*high confidence*): *{4.4.2.1, 4.4.2.2}*

- National governments play key roles in adaptation planning and implementation (*robust evidence, high agreement*) through coordinating actions and providing frameworks and support. While local government and the private sector have different functions, which vary regionally, they are increasingly recognized as critical to progress in adaptation, given their roles in scaling up adaptation of communities, households and civil society and in managing risk information and financing (*medium evidence, high agreement*). *{4.4.2.1}*

- Institutional dimensions of adaptation governance, including the integration of adaptation into planning and decision-making, play a key role in promoting the transition from planning to implementation of adaptation (*robust evidence,*

high agreement). Examples of institutional approaches to adaptation involving multiple actors include economic options (e.g., insurance, public-private partnerships), laws and regulations (e.g., land-zoning laws) and national and government policies and programmes (e.g., economic diversification). *{4.2, 4.4.2.1, Table SPM.3}*

- In principle, mechanisms that set a carbon price, including cap and trade systems and carbon taxes, can achieve mitigation in a cost-effective way but have been implemented with diverse effects due in part to national circumstances as well as policy design. The short-run effects of cap and trade systems have been limited as a result of loose caps or caps that have not proved to be constraining (*limited evidence, medium agreement*). In some countries, tax-based policies specifically aimed at reducing GHG emissions—alongside technology and other policies—have helped to weaken the link between GHG emissions and GDP (*high confidence*). In addition, in a large group of countries, fuel taxes (although not necessarily designed for the purpose of mitigation) have had effects that are akin to sectoral carbon taxes. *{4.4.2.2}*

- Regulatory approaches and information measures are widely used and are often environmentally effective (*medium evidence, medium agreement*). Examples of regulatory approaches include energy efficiency standards; examples of information programmes include labelling programmes that can help consumers make better-informed decisions. *{4.4.2.2}*

- Sector-specific mitigation policies have been more widely used than economy-wide policies (*medium evidence, high agreement*). Sector-specific policies may be better suited to address sector-specific barriers or market failures and may be bundled in packages of complementary policies. Although theoretically more cost-effective, administrative and political barriers may make economy-wide policies harder to implement. Interactions between or among mitigation policies may be synergistic or may have no additive effect on reducing emissions. *{4.4.2.2}*

- Economic instruments in the form of subsidies may be applied across sectors, and include a variety of policy designs, such as tax rebates or exemptions, grants, loans and credit lines. An increasing number and variety of renewable energy (RE) policies including subsidies—motivated by many factors—have driven escalated growth of RE technologies in recent years. At the same time, reducing subsidies for GHG-related activities in various sectors can achieve emission reductions, depending on the social and economic context (*high confidence*). *{4.4.2.2}*

Co-benefits and adverse side effects of mitigation could affect achievement of other objectives such as those related to human health, food security, biodiversity, local environmental quality, energy access, livelihoods and equitable sustainable development. The potential for co-benefits for energy end-use measures outweighs the potential for adverse side effects whereas the evidence suggests this may not be the case for all energy supply and agriculture, forestry and other land use (AFOLU) measures. Some mitigation policies raise the prices for some energy services and could hamper the ability of societies to expand access to modern energy services to underserved populations (*low confidence*). These potential adverse side effects on energy access can be avoided with the adoption of complementary policies such as income tax rebates or other benefit transfer mechanisms (*medium confidence*). Whether or not side effects materialize, and to what extent side effects materialize, will be case- and site-specific, and depend on local circumstances and the scale, scope and pace of implementation. Many co-benefits and adverse side effects have not been well-quantified. *{4.3, 4.4.2.2, Box 3.4}*

Technology policy (development, diffusion and transfer) complements other mitigation policies across all scales, from international to sub-national; many adaptation efforts also critically rely on diffusion and transfer of technologies and management practices (*high confidence*). Policies exist to address market failures in R&D, but the effective use of technologies can also depend on capacities to adopt technologies appropriate to local circumstances. *{4.4.3}*

Substantial reductions in emissions would require large changes in investment patterns (*high confidence*). For mitigation scenarios that stabilize concentrations (without overshoot) in the range of 430 to 530 ppm CO_2-eq by 2100[19], annual investments in low carbon electricity supply and energy efficiency in key sectors (transport, industry and buildings) are projected in the scenarios to rise by several hundred billion dollars per year before 2030. Within appropriate enabling environments, the private sector, along with the public sector, can play important roles in financing mitigation and adaptation (*medium evidence, high agreement*). *{4.4.4}*

[19] This range comprises scenarios that reach 430 to 480 ppm CO_2-eq by 2100 (*likely* to limit warming to 2°C above pre-industrial levels) and scenarios that reach 480 to 530 ppm CO_2-eq by 2100 (without overshoot: *more likely than* not to limit warming to 2°C above pre-industrial levels).

Financial resources for adaptation have become available more slowly than for mitigation in both developed and developing countries. Limited evidence indicates that there is a gap between global adaptation needs and the funds available for adaptation (*medium confidence*). There is a need for better assessment of global adaptation costs, funding and investment. Potential synergies between international finance for disaster risk management and adaptation have not yet been fully realized (*high confidence*). *{4.4.4}*

SPM 4.5 Trade-offs, synergies and interactions with sustainable development

Climate change is a threat to sustainable development. Nonetheless, there are many opportunities to link mitigation, adaptation and the pursuit of other societal objectives through integrated responses (*high confidence*). Successful implementation relies on relevant tools, suitable governance structures and enhanced capacity to respond (*medium confidence*). *{3.5, 4.5}*

Climate change exacerbates other threats to social and natural systems, placing additional burdens particularly on the poor (*high confidence*). Aligning climate policy with sustainable development requires attention to both adaptation and mitigation (*high confidence*). Delaying global mitigation actions may reduce options for climate-resilient pathways and adaptation in the future. Opportunities to take advantage of positive synergies between adaptation and mitigation may decrease with time, particularly if limits to adaptation are exceeded. Increasing efforts to mitigate and adapt to climate change imply an increasing complexity of interactions, encompassing connections among human health, water, energy, land use and biodiversity (*medium evidence, high agreement*). *{3.1, 3.5, 4.5}*

Strategies and actions can be pursued now which will move towards climate-resilient pathways for sustainable development, while at the same time helping to improve livelihoods, social and economic well-being and effective environmental management. In some cases, economic diversification can be an important element of such strategies. The effectiveness of integrated responses can be enhanced by relevant tools, suitable governance structures and adequate institutional and human capacity (*medium confidence*). Integrated responses are especially relevant to energy planning and implementation; interactions among water, food, energy and biological carbon sequestration; and urban planning, which provides substantial opportunities for enhanced resilience, reduced emissions and more sustainable development (*medium confidence*). *{3.5, 4.4, 4.5}*

State of California
2030 TARGET SCOPING PLAN UPDATE
CONCEPT PAPER
June 17, 2016

Executive Order B-30-15 established an updated California GHG reduction target of 40 percent below 1990 levels by 2030. California Air Resources Board (ARB) staff is providing this 2030 Draft Scoping Plan Update (Draft Scoping Plan) concept paper to describe potential policy concepts to achieve the 2030 target. The content of this paper has been informed by several public workshops and meetings held to date, beginning with the Governor's Climate Change Strategy Pillar Workshops held in summer 2015. Since then, ARB staff, in collaboration with other State agencies, has held numerous public workshops to develop the Draft Scoping Plan, including several Environmental Justice Advisory Committee meetings, a public meeting to discuss the greenhouse gas (GHG) modeling and economic analysis that will be included in the Draft Scoping Plan, and other sector-specific public workshops. These multi-agency meetings provided State agencies the opportunity to share their near- and long-term visions for climate policy and actively solicited the public's comments, concerns and questions. A full list of the Draft Scoping Plan workshops held to date can be found on ARB's Scoping Plan website: http://www.arb.ca.gov/cc/scopingplan/meetings/meetings.htm.

This paper provides additional opportunities for public and stakeholder engagement and input prior to release of the Draft Scoping Plan later this year. The intent of the paper is to inform an ongoing stakeholder process for how to most effectively achieve a 40 percent reduction in GHG emissions by 2030 as compared to 1990 statewide GHG emissions. The process going forward will include additional workshops that will be held in 2016 and early-2017. All written comments submitted on this paper will be posted for public review at the website below, and will be reviewed by State agencies as we continue to coordinate on proposing final concepts for evaluation and consideration through the ongoing public process. Comments on this paper will be considered as the Draft Scoping Plan is developed and released for public review in summer 2016. Comments on this paper can be submitted through July 8, 2016, here: http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm

Introduction

California has been a leader in addressing greenhouse gases (GHGs) since the passage of Assembly Bill 32 (AB 32), the California Global Warming Solutions Act of 2006 (AB 32, Statutes of 2006, Chapter 488), which represented a defining moment in California's long history of environmental stewardship and secured the State's role as a leader in reducing greenhouse gas (GHG) emissions. California seeks to fight climate change by employing a comprehensive, long-term approach to cut the State's GHG emissions to 1990 levels by 2020 and to maintain and continue reductions post 2020. Since the time the first energy efficiency requirements were adopted, to the Renewable Portfolio Standard (RPS), to the Pavley Advanced Clean Car Standards, and the recent proposed Short Lived Climate Pollutant Strategy, the State has been consistent and bold in its efforts to address climate change and serve as an example of how other regions can take similar action in reducing GHGs.

California is currently ranked as the world's sixth largest economy, up from number ten in 2012. Yet we reduced GHGs per capita and GHGs per gross domestic product while steadily growing the economy. Over the past half a century, we have made great strides in addressing air pollution and continue to seek and implement new policies to meet national and state air quality standards. At the same time, the State is on its way to reducing GHG emissions to meet the 2020 limit and accomplish our longer-term climate goals.

California's current climate program relies on a mix of an economy-wide cap with a market-based allowance trading system, accompanied by a suite of sector specific policies such as an RPS for electricity, a low carbon fuel standard, and strong vehicle emission standards. But, all these policies need to be reexamined and in some cases may require legislative reauthorization.

Despite California's marked progress, greater innovation and effort is needed to avoid the worst consequences of climate change. Recognizing the threat to California's future, Governor Brown called on California to pursue a new and ambitious set of objectives to continue to reduce GHG emissions by 2030 and beyond. In his January 2015 inaugural address, Governor Brown identified five key climate change strategy "pillars," which recognize that several major areas of the California economy will need to reduce their emissions to meet California's ambitious climate change goals. These five pillars are:

1. Reducing today's petroleum use in cars and trucks by up to 50%;
2. Increasing from one-third to 50% our electricity derived from renewable sources;
3. Doubling the efficiency savings achieved at existing buildings and making heating fuels cleaner;
4. Reducing the release of methane, black carbon, and other short lived climate pollutants; and
5. Managing farm and rangelands, forests and wetlands so they can store carbon.

Consistent with these goals, Governor Brown signed Executive Order B-30-15 in April 2015 establishing a California GHG reduction target of 40 percent below 1990 levels by 2030. This new emissions reduction target represents the most aggressive goal set by any government in North America to reduce GHG emissions over the next decade and a half. This new target is consistent with the path necessary to reach the scientifically established levels needed to limit global warming below 2 degrees Celsius (°C) – the warming threshold at which scientists agree that there will likely be major climate disruptions – and aligns California's GHG reduction targets with those of leading international governments.

Executive Order B-30-15 calls on ARB to update the AB 32 Climate Change Draft Scoping Plan to incorporate the 2030 target. The Draft Scoping Plan will serve as the framework to define the State's climate change priorities for the next 15 years and beyond. In addition, this Draft Scoping Plan will recognize the intersection of the pillars and the imperative to balance the outcomes of each pillar as we achieve our climate goals and maintain California's values and iconic and lifestyles.

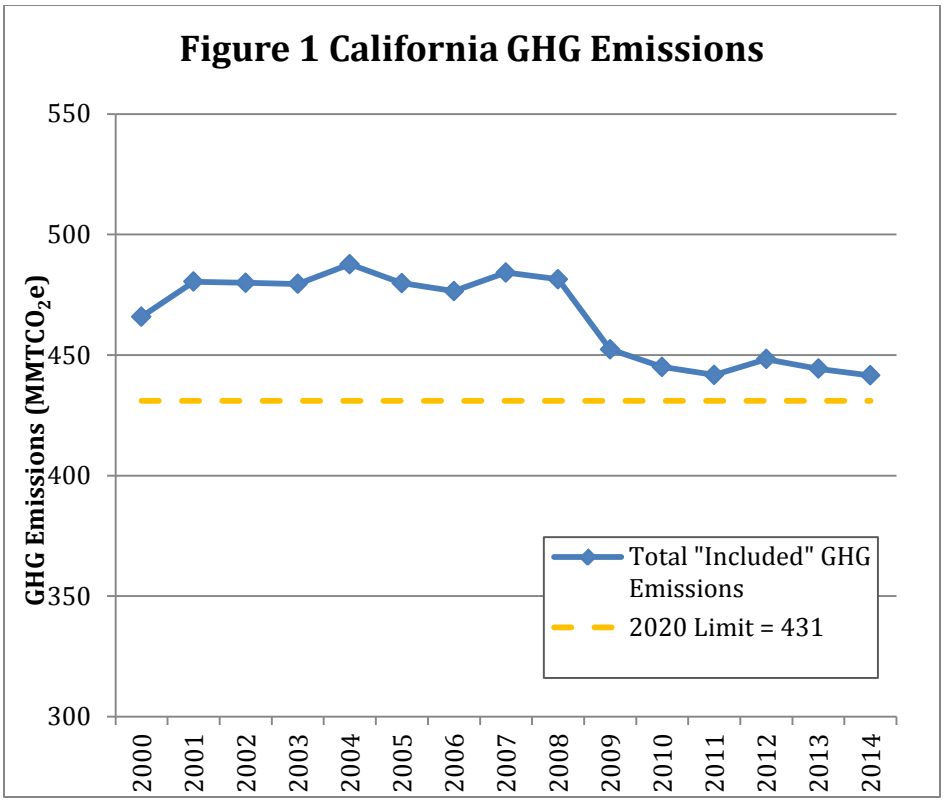
The 2030 target reflects the same science that informs the recent agreement reached in Paris by the 2015 Conference of Parties to the United Nations Framework Convention on Climate Change, aimed at keeping the global temperature rise below 2°C. California continues to play a leadership role by demonstrating that reducing carbon is compatible with a robust economy. Like California, other subnational jurisdictions are ready to take action. With the Under 2 MOU, which originated from a partnership between California and Baden-Wurttemberg, 128 jurisdictions have signed on to the goal of limiting GHGs 80 to 95 percent, or 2 metric tons per capita carbon dioxide equivalent emissions by 2050, leading the way for the world.

Progress

California has made progress toward achieving the 2020 statewide GHG target while also reducing criteria and toxic pollutants and supporting economic growth. As shown in Figure 1, in 2014, total GHG emissions decreased by 2.8 million metric tons of CO_2 equivalents ($MMTCO_2e$) compared to 2013, representing an overall decrease of 9.4% since peak levels in 2004. The 2014 GHG Emission Inventory and a description of the methodology updates can be accessed here: http://www.arb.ca.gov/cc/inventory/inventory.htm

California's annual statewide GHG emission inventory, which was used to create Figure 1, has historically been the primary tool for tracking GHG emissions trends. Aligning this inventory with the Intergovernmental Panel on Climate Change (IPCC) guidelines allows California to share a consistent method to compare GHG profiles with other subnational jurisdictions and nations.

The 2014 GHG Emission Inventory (2016 Edition) includes improved methodology updates. For example, to align the GHG inventory with the IPCC guidelines, starting with 2014 GHG Emission Inventory, ARB is separating biogenic CO_2 from transportation fuels from the total emissions and tracking those emissions separately as informational items. Figure 1 provides the GHG inventory trend using this new method. Additional information on the methodology for the GHG inventory can also be found here: http://www.arb.ca.gov/cc/inventory/inventory.htm



Although the inventory will remain critical piece for GHG accounting, it can now be supplemented using data derived from individual GHG emissions reducing programs. In the Draft Scoping Plan, to better track progress towards achieving our statewide GHG targets, we will explore how to structure an accounting framework that uses the GHG inventory, but incorporates GHG emissions related to land use conversion when biofuels are produced and supplied to California as a result of our Low Carbon Fuel Standard. We will also explore how flows of cap-and-trade program compliance instruments between California and Québec can be incorporated into such an accounting framework.

The exchange of carbon dioxide between the atmosphere and California's natural and working lands sector is not currently quantified and is excluded from the inventory. A natural and working lands carbon inventory is essential for monitoring land-based activities that may increase or decrease carbon sequestration over time. ARB staff is working to develop a comprehensive inventory of GHG fluxes from all of California's natural and working lands using International Panel on Climate Change (IPCC) design principles. The Draft Scoping Plan will describe ARB's progress and identify data gaps. Other state agencies, non-profit organizations, and research institutions are developing and testing methodologies and models to quantify GHG fluxes from California's natural and working lands. ARB's ongoing work on this inventory will serve as

one source of data to gauge the scope of GHG reduction potential from California's natural and working lands and monitor progress over time. ARB will evaluate other data sources and methodologies for use in validating or supporting the ARB inventory or project-scale tracking. As discussed later in this paper, interagency work is underway to integrate and account for the land use and management impacts of development, transportation, housing and energy policies into this Draft Scoping Plan.

The Strategy

"The whole is greater than the sum of its parts." - Aristotle

Integrated System

From our coasts to our mountains, surfers, hikers, skiers, mountain climbers, fishing enthusiasts, and many others, share a passion for California's natural landscapes. Our State Parks also reflect a rich cultural history that includes Native American, Spanish, Mexican, Asian, European, U.S. and other influences. California has a diverse economy – from energy production to manufacturing to farming to technology to cinema and goods movement. As we chart a path to achieving the 2030 and 2050 GHG targets, we must care for the whole. In the context of the Draft Scoping Plan, caring for the whole means considering California as more than the sum of its sectors. Actions in one sector need to take into account their impacts on other sectors.

To establish a comprehensive approach to achieve the State's climate goals, the plan will incorporate multiple ongoing State efforts. For example, as we address future mobility, we must show how existing efforts underway – such as the Sustainable Freight Plan, Mobile Source Strategy, California Transportation Plan 2040, urban planning, and goals for enhancement of the natural environment – can complement each other while providing air quality and climate benefits. Each of these efforts is important in its own right, but looked at together they provide insights into the trade-offs of policies across all sectors and tell a larger story about how the State will move towards a sustainable and resilient future. The Scoping Plan can help identify the policy choices that will minimize costs and optimize "win–win" solutions, while also recognizing that it is often difficult to accomplish all of the State's goals at the same time.

Flexibility

Strategies to reduce GHG emissions vary and require ongoing evaluations to accommodate innovation and change. Actions and tools recommended by the Draft Scoping Plan must include a flexible framework for implementation. Combinations of regulations, incentives, voluntary action, private-public partnerships, and support from non-governmental organizations can be leveraged together to promote desired actions and achieve 2030 climate goals. The Draft Scoping Plan will include a discussion about the important role that each of these tools play alone and together, and provide illustrative examples of successful implementation of these tools to date. With 2050 in mind, we need to find ways to encourage innovation and voluntary actions today that support and exceed the policies and measures we include in this Draft Scoping Plan.

The State will need to encourage and support near-term actions to reduce emissions through financial incentives, collaboration to overcome barriers, and other market support as needed, before some potential regulations will be feasible. We also know that successful long-term planning is achievable only through a collaborative process. For example, Caltrans is looking to maximize collaboration and leverage funding through an integrated approach to planning, designing, building and operating transportation assets. Integrating local, regional, and State priorities can help identify opportunities for strategic investment that addresses multiple mobility objectives, and collaboration between public and private stakeholders ensures the built system addresses future needs and functions appropriately.

Promoting Resilient Economic Growth

The existing policies, strategies, plans, and regulations that we already have in place are helping many California businesses to better compete in a global economy, and have created new investments, businesses, and jobs to support a clean energy economy. We have learned that California's portfolio-based climate strategy can achieve great success when accompanied by consistent and rigorous GHG monitoring and reporting, a robust public process, and an effective enforcement program for the few that chose not to play by the rules. Our experience has also shown us that California's economy and infrastructure can be strengthened while also achieving other important environmental benefits such as reductions in criteria pollutants and air toxics, especially in California's most vulnerable communities.

The benefits achieved as a result of the Draft Scoping Plan are part of California's comprehensive strategy to achieve lasting emissions reductions throughout the economy. California's strategic vision for achieving a 40 percent reduction in GHG emissions by 2030 is based on the principle that economic prosperity and environmental sustainability can be achieved together. Undertaking the actions that will be presented in the Draft Scoping Plan presents opportunities for the future, but progress towards our goals is already evident today. For example, in 2015, California added more than 20,000 new jobs in the solar sector. This was more than half of the positions in this industry across the nation.

Achieving our global goals requires a structural shift in the global economy, which is already underway. Successfully driving this transition will require cleaner and more efficient technologies, new policies and incentives that better recognize and reward innovation, and prioritize low carbon investments. These fundamental shifts will create economic opportunities in the energy and transportation sectors leading to transformative changes in the management and conservation of our natural and working lands, land use, and urban environments. These efforts are already underway, as highlighted through the development and implementation of Sustainable Communities Strategies (SCSs) pursuant to Senate Bill (SB) 375, which link land use, transportation and climate policy, and are designed to reduce per capita GHG emissions while providing benefits ranging from improved air quality and expanded transportation options to revitalization of city centers and investment in disadvantaged communities. SB 375 is just one of many ways to address land use and provide climate benefits. The Draft Scoping Plan will identify new ways to promote the technologies and infrastructure required to meet our collective climate goals, while also presenting the vision for California's continuing efforts to foster a clean energy economy.

Protecting, Enhancing, Innovating, and Increasing Sequestration in the Natural Environment

California's natural and working lands are unique and widely celebrated. The State's quarter depicts Yosemite Valley's Half Dome and conservationist John Muir, highlighting the State's self-identification with its natural landscapes. These lands support clean air, wildlife and pollinator habitat, and vibrant rural economies. They are home to the largest and most diverse sources of food and fiber production and renewable energy in the United States. Forests,

rangelands, farms, wetlands, riparian areas, deserts, coastal areas, and the ocean store substantial carbon in biomass and soils.

Natural and working lands are integral to the State's climate change strategy. Storing carbon in trees, plants, aquatic vegetation, and in the soil is one of the most effective ways to remove GHGs from the atmosphere. The Draft Scoping Plan will include policies and programs that prioritize protection and enhancement of California's landscapes, including urban landscapes. As we think about the policies to include in the Draft Scoping Plan, we cannot ignore the relationships between sectors or the adverse impacts that climate change is having on the environment itself. We must consider important trade offs in developing the State's climate strategy and understand the near and long-term impacts of various policy scenarios on topics such as farmland conversion, urban sprawl, and increased vehicle miles traveled (VMT). We must also address the increasing trend in the severity of wildfires in California due to climate change, and understand how best to increase carbon sequestration in forests and other natural lands over time. The Draft Scoping Plan will build off of ongoing efforts to identify targets for natural and working lands, such as through the Forest Carbon Plan,[1] and identify policies that directionally set us on the path towards achieving the vision for the sector even in the face of scientific and methodological uncertainty.

A Draft Scoping Plan workshop held on March 23, 2016, focused on the natural working lands sector.[2] As described at the March 2016 workshop, the high-level objectives for the State's strategy for natural and working lands include:

- Increase protections on natural and working lands to reduce the rate of conversion to intensified uses, to both preserve lands' sequestration potential and promote infill and compact development.
- Manage and restore land to increase carbon storage and minimize GHG emissions in a sustainable manner so that the carbon bank is resilient and grows over time.
- Seek synergies that optimize contributions from natural and working lands while sustaining local economies by researching and developing appropriate bioenergy, food crop, water system and waste management technology, as well as product manufacturing, that serves to support sustainable resource management.
- Harness nature's benefits through urban greening to reduce GHG emissions and increase carbon storage in urban landscapes; cool urban

[1] Forest Climate Action Team website: http://www.fire.ca.gov/fcat/
[2] The materials for this workshop are located here: http://www.arb.ca.gov/cc/scopingplan/meetings/meetings.htm

heat islands; encourage active transportation, reduce air and water pollution; allow for groundwater recharge; improve energy efficiency, and; improve human health and community resiliency.

As discussed later in this paper, the GHG modelling and economic analysis that will be included in the Draft Scoping Plan will illustrate possible policy scenarios that can help the State to achieve the 2030 and 2050 GHG reduction targets. Each policy scenario evaluated in the Draft Scoping Plan will include the abovementioned four high-level objectives in order to ensure we achieve the vision for the State's natural and working lands. How these high-level objectives translate to specific policies and implementation mechanisms will be part of the ongoing discussion with stakeholders.

The list of natural working lands objectives for the Draft Scoping Plan are discussed in detail in the Natural Working Lands Discussion Paper found here: http://www.arb.ca.gov/cc/scopingplan/meetings/meetings.htm

Improving Public Health

Climate change is already impacting the health of our communities. Those facing the greatest health inequities include low-income individuals and households, the very young and the very old, communities of color, and those who have been marginalized or discriminated against based on gender, race/ethnicity, or sexual orientation.[3] Addressing climate change presents a significant opportunity to improve public health for all of California's residents and work towards making our State the healthiest in the nation.

Climate mitigation efforts focus primarily on moving "upstream" to reduce GHG emissions at the source. Upstream GHG mitigation strategies address the root cause of impacts thereby preventing adverse health outcomes and promoting multiple benefits including long-term community health and well-being. Public health and climate actions and interventions exist on a spectrum and can often overlap and address multiple issues simultaneously. For example, certain "upstream" measures to reduce GHG emissions, such as improvements in the built environment, can help communities better adapt and be more resilient to climate impacts, can promote long-term, durable community health benefits, and can also improve individual health conditions. As part of the Draft Scoping Plan, we will present a public health assessment that will discuss key statewide climate

[3] California Department of Public Health (CDPH). 2015. The Portrait of Promise: The California Statewide Plan to Promote Health and Mental Health Equity. A Report to the Legislature and the People of California by the Office of Health Equity. Sacramento, CA: California Department of Public Health, Office of Health Equity.

mitigation measures and their potential impacts on public health, especially co-benefits, such as reductions in criteria and toxic air contaminants.

Environmental Justice

Fair and healthy climate action requires addressing the inequities that create and intensify community vulnerabilities. The capacity for resilience in the face of climate change is significantly driven by living conditions and the forces that shape them, such as income, education, housing, transportation, environmental quality, access to services such as health care, healthy foods and water, and safe spaces for physical activity, and good health status. Thus, strategies such as alleviating poverty, increasing access to opportunity, improving living conditions, and reducing health and social inequities will result in more climate-resilient communities. Promoting a low-carbon California economy will reduce GHG emissions and create a healthier environment for all of California's residents, especially those living in the State's most disadvantaged communities.

It is important to note that both climate change and the health inequities we see in our communities share similar root causes: the inequitable distribution of social, political and economic power. These power imbalances result in systems (i.e. economic, transportation, land use, etc.) and conditions that drive both health inequities and GHG emissions. As a result, we see communities with inequitable living conditions, such as low-income communities of color living in more polluted areas, facing climate change impacts that compound and exacerbate existing sensitivities and vulnerabilities. Fair and healthy climate action requires addressing the inequities that create and intensify community vulnerabilities.

AB 32 calls for ARB to convene an Environmental Justice Advisory Committee (Committee), to advise the Board in developing the Draft Scoping Plan, and any other pertinent matter in implementing AB 32. It requires that the Committee be comprised of representatives from communities in the State with the most significant exposure to air pollution, including, but not limited to, communities with minority populations or low-income populations, or both. As with the initial Draft Scoping Plan and first update, this Draft Scoping Plan development process includes consultation with the Committee. At the April 4, 2016 public meeting, the Committee provided draft initial recommendations for the Draft Scoping Plan, and staff are continuing to meet with the Committee to discuss these recommendations. The Committee will be making formal recommendations on the policies to be considered in the Draft Scoping Plan, will continue to hold

regular public meetings, and lead local environmental justice community discussions to inform the Draft Scoping Plan. More information about the Committee and recommendations on previous and current Draft Scoping Plans is located here: http://www.arb.ca.gov/cc/ejac/ejac.htm

It is critical that environmental justice communities share in the benefits of the cleaner economy that California is building. Low-income customers that are enrolled in the California Alternate Rates for Energy (CARE) Program or the Family Electric Rate Assistance (FERA) Program are also eligible to receive a rebate under the California Climate Credit[4], or a credit on residential and small business energy bills resulting from the sale of allowances received by investor-owned utilities as part of the Cap-and-Trade program.[5] SB 1018 and other implementing legislation requires that Cap-and-Trade auction monies deposited into the Greenhouse Gas Reduction Fund (GGRF) be used to further the purposes of AB 32, while also fostering job creation by promoting in-state GHG emissions reduction projects carried out by California workers and businesses. SB 535 directs State and local agencies to make significant investments from monies deposited into the GGRF that improve California's most vulnerable communities. Specifically, SB 535 requires that a minimum of 25 percent of these investments are allocated to projects that provide benefits to disadvantaged communities, and a minimum of 10 percent are allocated to projects located within and providing benefits to disadvantaged communities. Based on agency data reported as of December 2015, 51% of the $912 million dollars implementing California Climate Investments are funding projects that provide benefits to disadvantaged communities; 39% of the $912 million are funding projects located within disadvantaged communities.[6]

Relying on Sound Science and Research

Sound science underpins, updates and strengthens climate policy. The scientific record overwhelmingly and undeniably demonstrates that climate change is occurring. It also connects human-related activities to the atmospheric burden of CO_2 with expansion at an unprecedented rate. As we develop this Draft Scoping Plan, time matters. The policies that are included must rapidly lead to real results to avoid the most catastrophic impacts of climate change. In the Draft Scoping Plan, we will identify policies based on solid science and identify additional research needs, while also recognizing the need for flexibility in the face of a changing climate. Sectors such as natural and working lands have very

[4] California Public Utilities Commission. California Climate Credit: http://www.cpuc.ca.gov/climatecredit/
[5] California Public Utilities Commission. CARE/FERA Programs: http://www.cpuc.ca.gov/General.aspx?id=976?.
[6] Excluding High Speed Rail.

complex biological systems. While we have made significant progress in understanding the role forests can play in climate change mitigation, we need to continue our work on other landscapes. Ongoing research to better understand those systems will allow for additional opportunities to set targets and identify actionable policies.

Setting the Path to 2050

While this Draft Scoping Plan will chart the path to achieving the 2030 statewide GHG target, we need momentum to propel us to the 2050 statewide GHG target (80 percent below 1990 levels). This Draft Scoping Plan will require us to consider what policies are needed for the mid-term and long-term, knowing that some policies for the long-term must begin implementation now. At the same time, we must consider policies for 2030 that do not simply dead end in 2030, but rather can continue to help support the State's long-term climate objectives. As with all investments, whether financial or personal, the approach we take must balance risk, reward, longevity, and timing. For example, do we promote renewable gas in the transportation or electricity sectors, or is this resource best utilized for displacement of fossil natural gas in the residential and industrial sectors? For the forest sector, are we comfortable with policies that may result in some near-term carbon loss, but ultimately support more resilient and healthier forests in the longer timeframe? And, are we willing to pursue policies that we know are needed for the 2050 target, but may not significantly reduce GHG emissions in the near-term?

Intergovernmental Collaboration

Federal, state, and local action can be complementary. We have already seen Federal action through the Clean Air Act, development of the Clean Power Plan to limit GHGs from power plants, and the advancement of methane rules for oil and gas production. Regional and local governments and agencies are leaders in addressing climate change and are uniquely positioned to reduce emissions from certain sources, especially by reducing the demand for electricity, transportation fuels, and natural gas. Many local governments have already initiated efforts to reduce GHG emissions beyond those required by the State. For example, many cities and counties are improving their municipal operations by upgrading their vehicle fleets, retrofitting government buildings and streetlights, purchasing greener products, and implementing waste-reduction policies. In addition, they are adopting more sustainable codes, standards, and general plan improvements to reduce their community's footprints and emissions.

The State is striving to provide a supportive framework to advance these and other local efforts, while also recognizing the need to build on, and export, this success to other regional and local governments through California and beyond.

Local actions are critical for implementation of California's ambitious climate agenda. Local municipal code changes, zoning changes, or policy directions that apply broadly to the community within the general plan or climate action plan area can help promote the deployment of renewable, zero-emission, and low-carbon technologies such as zero net energy buildings, renewable fuel production facilities, and zero emission charging stations. Local decision-making has an especially important role in achieving reductions of GHG emissions generated from transportation. Over the last 60 years, development patterns have led to sprawling suburban neighborhoods, a vast highway system, growth in automobile ownership, and under-prioritization of infrastructure for public transit and active transportation. Local decisions about these policies today can establish a more sustainable built environment for the future. Local governments can incentivize locally generated renewable energy and infrastructure for alternative fuels and electric vehicles, implement water efficiency measures, develop waste-to-energy and waste-to-fuel projects, and enhance and preserve urban forests and other greenspace. Indeed, many local agencies are already implementing ambitious climate strategies. These types of local actions complement statewide measures and may be more cost effective and provide more co-benefits than relying exclusively on top-down statewide regulations to achieve the State's climate stabilization goals. The Draft Scoping Plan will explore the potential benefit of any regional or local targets to assist local agencies in their efforts to address climate change.

International efforts

California is not alone in its efforts to address climate change. The agreement reached in Paris by the 2015 Conference of Parties to the United Nations Framework Convention on Climate Change (UNFCCC) aimed at keeping the global temperature rise below 2°C, is spurring action across the world. The results of this agreement will translate into worldwide action to reduce GHGs and support decarbonization across the global economy. And, it is not just action and coordination at the international and national levels that is important. Subnational governments are front and center on this issue. With the establishment of the Under 2 Memorandum of Understanding,[7] the Governors'

[7] Under 2 MOU website: http://under2mou.org/

Climate and Forests Task Force,[8] and the Western Climate Initiative,[9] among other partnership initiatives, subnational jurisdictions from the around the world are collaborating on how best to address climate change and are leading the way.

From its inception, AB 32 recognized the importance of California's climate leadership and engagement with other jurisdictions, and directed ARB to consult with the federal government and other nations to identify the most effective strategies and methods to reduce GHGs, manage GHG control programs, and to facilitate the development of integrated and cost-effective regional, national, and international GHG reduction programs. California undertook a two-pronged approach: first, we assessed our state-specific circumstances to develop measures that would apply specifically in California; and second, we simultaneously assessed which measures might lend themselves, through careful design and collaboration with other interested jurisdictions, toward linked GHG reduction programs. Under the Clean Air Act, California has a special role as an innovator and leader in the area of motor vehicle emission regulations, which allows our State to adopt motor vehicle emission standards that are stricter than federal requirements. These motor vehicle standards have been emulated around the country and the world, leading to widespread health benefits. Similarly, by enacting a comprehensive strategy that can be exported nationally and internationally, California can lead the world in truly tackling climate change.

Today, the State's Cap-and-Trade Program is linked with Québec's program; ongoing discussions to link with Ontario's emerging emissions trading system are underway. Low-carbon fuel mandates similar to California's Low Carbon Fuel Standard have been adopted by the U.S. EPA, and by other jurisdictions including Oregon, British Columbia, the European Union, and the United Kingdom. Over two dozen states have a renewable portfolio standard. California continues to discuss carbon pricing through a cap-and-trade program with international delegations. We have seen design features of our program incorporated into other emerging and existing programs, such as the European Union Emissions Trading System and China's developing national program.

Understanding the Challenge

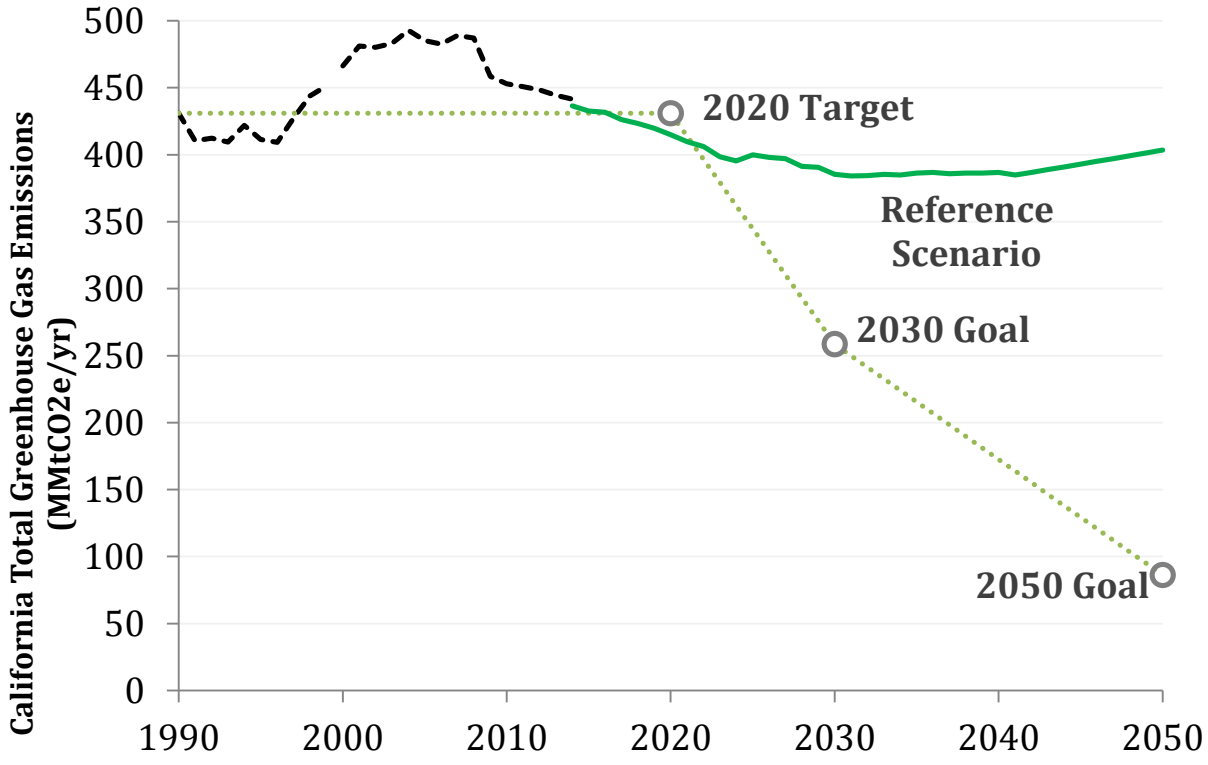
In charting the path towards the 2030 statewide GHG target, we first need to understand the amount of GHG reductions needed between now and 2030 to

[8] Governors' Climate and Forests Task Force website: http://www.gcftaskforce.org/
[9] Western Climate Initiative website: http://www.wci-inc.org/

reach our target. This is best understood by first modeling a reference case (also referred to as "Business as Usual", or BAU), which extends today's existing actions to 2030 to depict future GHG emissions levels. The forecasted level of statewide total GHG emissions in 2030 is expected without any further action to reduce GHGs. ARB held a workshop on January 15th, 2016, to provide additional details on the models that will be used to evaluate the Draft Scoping Plan (PATHWAYS and REMI PI+) and an overview of their use. The information provided at that workshop is located here: http://www.arb.ca.gov/cc/scopingplan/meetings/meetings.htm

Figure 2 provides the modeling results for a draft reference scenario (BAU) for the Draft Scoping Plan. The graph shows the State is expected to reduce emissions below the 2020 statewide GHG target, but additional effort will be needed to maintain and continue GHG reductions and meet the mid (2030) and long-term (2050) targets. The draft reference scenario (BAU) includes an updated methodology for estimating biofuel supplies.

Figure 2 Draft 2030 Target Draft Scoping Plan Reference Scenario



The same models will be used to conduct the analyses for the various scenarios that will be evaluated to achieve the 2030 statewide GHG target. There will be

future workshops on the modeling to consider the assumptions used for the reference case (BAU) and scenarios as they are designed. These workshops will allow economic reviewers, a core group of academic experts in economics, modeling, and technology, to present the findings of their analyses of the economic and technical assumptions, metrics, and tools proposed to be utilized. The assumptions used for the draft reference case is provided in Appendix A.

For the first time, the Draft Scoping Plan analysis will include estimates of the impact of land use both from business-as-usual approaches and proposed policies (GHG impacts and economic impacts). These estimates are not included in the draft reference case in Figure 2. State agencies are exploring how to estimate GHG emissions and sequestration trends for the natural working lands sector in the Draft Scoping Plan analysis. Although PATHWAYS does not directly calculate or model GHG emissions trends for the natural working lands sector, PATHWAYS can provide estimates regarding the amount of land conversion that would be required to achieve the State's renewable energy procurement goals related to utility-scale solar and wind and transportation targets. These estimates can be used to calculate the potential GHG emissions associated with the amount of land conversion required to build the new capacity and mobility. In doing so, the Draft Scoping Plan will identify potential trade-offs between renewable energy, land use impacts, and associated GHGs. Similarly, separate analyses will also examine the potential GHG impacts of more compact development, driven by SB 375, on the rate of land conversion for urbanization. Having the ability to quantify these types of emissions sources is important when we consider the impacts of energy and land use development policies on the natural and working lands sector.

Choosing a Path Forward

In this concept paper, we are presenting four potential high-level concepts for achieving the needed GHG reductions. Some policies are common to the scenarios if they are explicitly required in statute. For example, each scenario must include at least a 50 percent RPS because that is required under SB 350, Clean Energy and Pollution Reduction Act of 2015. To provide context for the potential high-level policy scenarios that could be evaluated in the Draft Scoping Plan, we must first understand the GHG reductions achieved by major policies, such as those included in SB 350 that can reasonably be expected across all scenarios. The information provided below is our best available data to help stakeholders consider the high-level concepts and provide input before modeling of any policies.

As no modeling work for the Draft Scoping Plan has begun, this discussion relies on previous work completed for the 2014 California State Agencies' PATHWAYS Project: Long-term Greenhouse Gas Reduction Scenarios (PATHWAYS).[10] This model was designed by Energy & Environmental Economics (E3) to evaluate the feasibility and cost of a range of GHG reduction scenarios in California.

Two 2014 California State Agencies' PATHWAYS Project scenarios that represent emissions reductions that could be achieved through the implementation of complementary policies through 2030 are called Straight Line and Early Deployment. None of the scenarios included California's cap and trade program. The Straight Line scenario is distinguished by high renewable energy, fuel cell and battery electric vehicles, energy efficiency and electrification. The Early Deployment scenario is similar to Straight Line scenario but with additional focus on near-term air quality and GHG actions.

Table 1 outlines the GHG emissions forecast for the 2014 California State Agencies' PATHWAYS Project two policy scenarios, which include the incremental GHG reductions achieved through complementary policies.

Table 1: 2014 California State Agencies' PATHWAYS Project Emissions MMTCO_2e Forecasts

	2020	2025	2030
Straight Line	390.9	350.9	289.4
Early deployment	387.3	338.8	267.9

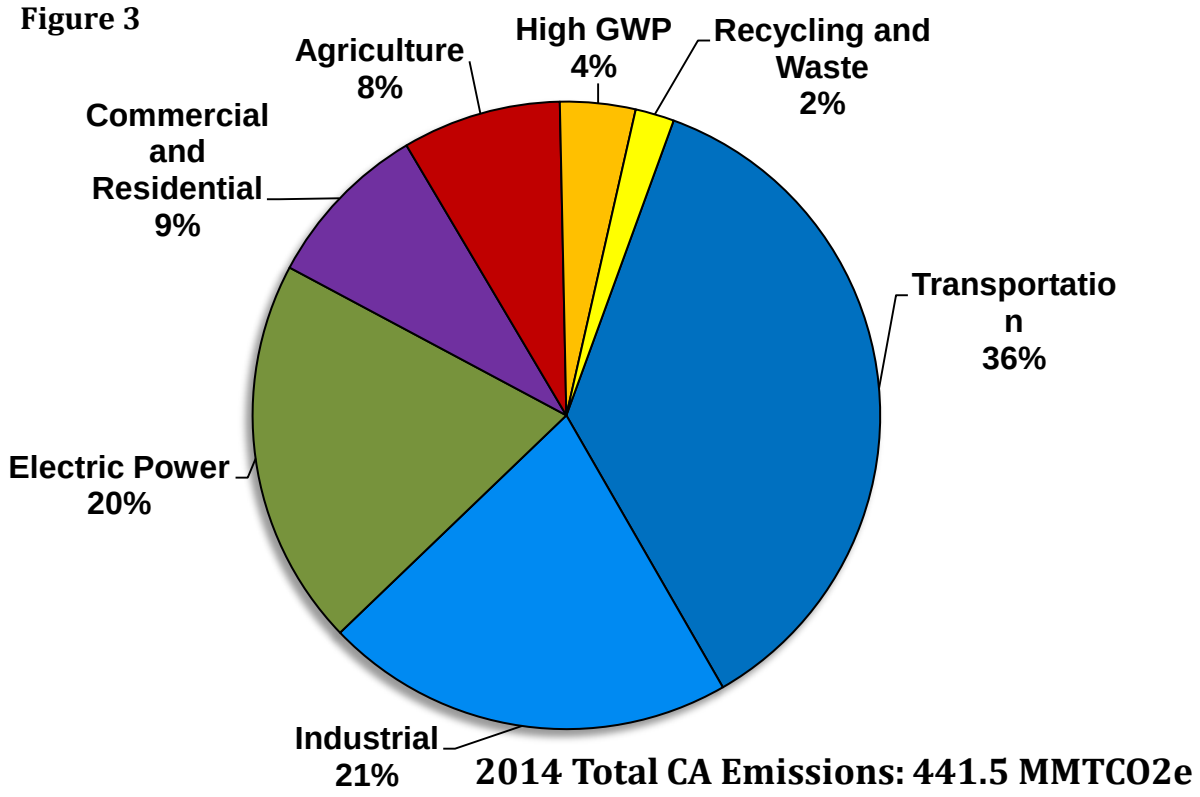
None of the 2014 California State Agencies' PATHWAYS Project scenarios reach the GHG target of a 40 percent reduction below 1990 levels by 2030 (i.e. 260 MMTCO_2e). Reaching this target would require a cumulative reduction of approximately 752 MMTCO_2e from 2021 through 2030. To reach the goal of 40 percent below 1990 levels, additional policies are required to provide GHG reductions of approximately 127 to 219 MMTCO_2e cumulatively from 2021 to 2030 (i.e., an additional 17 to 29 percent), conditional on the emission reductions that would be achieved through complementary policies and uncertainty related to technology development and deployment, legal challenges, and reduction

[10] The state agency collaborators on the project include California Air Resources Board, the California Independent System Operator, the California Public Utilities Commission, and the California Energy Commission using the PATHWAYS model. Results are available here: https://ethree.com/public_projects/energy_principals_study.php

mandates at the national and international levels. The 2014 California State Agencies' PATHWAYS Project results can serve as a rough estimate to help evaluate the high-level policy concepts that are presented in this paper. What is clear from this work is that keeping many of the existing policies at existing stringencies, while increasing the RPS to 50% and doubling energy efficiency in existing buildings to reflect SB 350 requirements, will not be sufficient to achieve the 2030 target.

It is also important to understand the sources of emissions when considering opportunities for policies and programs to reduce GHGs. Figure 3 provides the percent contribution to statewide emissions from the main economic sectors as reflected in the 2014 GHG Emission Inventory (2016 Edition).[11]

Figure 3



Climate change mitigation policies must be considered in the context of the sector's contribution to the State's total GHGs. The transportation, electricity (in-state and imported), and industrial sectors are the largest sectors for GHGs in the inventory and present the largest opportunities for GHG reductions. However, to ensure decarbonization across the entire economy, policies must be

[11] Based on 100-year global warming potentials (GWP) and the IPCC Fourth Assessment Report (FAR).

considered for all sectors. Policies that support energy efficiency, alternative fuels, and renewable power can also provide co-benefits for criteria and air toxic pollutants.

Any specific policies identified within the Draft Scoping Plan will be subject to a subsequent analytical and public process to develop and identify the full requirements and process for implementation. For example, a change in the Low Carbon Fuel Standard Carbon Intensity target would take effect after a subsequent rulemaking for that regulation that would include its own public process, CEQA, economic, and public health analyses. Stakeholders should also be aware that many large policies for reducing emissions towards the 2030 target are already known. For example, the increased RPS and energy efficiency requirements and various transportation plans will go far in reducing GHGs towards achieving the 2030 target. The challenge before us is to identify what additional policies or program enhancements we need to achieve the remaining amount of GHG reductions in a complementary, flexible, and cost effective manner to achieve the 2030 target. These policies should continue to encourage reductions beyond 2030 to keep us on track to stabilize climate. Policies that ensure economy-wide investment decisions incorporate consideration of GHG emissions are particularly important.

At the same time, we must acknowledge the integrated nature of our built and natural environments and polices. In the Draft Scoping Plan, each of the policies directed at the built environment must be considered against the high level goals for the natural working lands sector. While emissions from the agriculture and natural lands sector are lower, policies that support these sectors can reduce emissions and sequester carbon, while also providing ecosystem benefits such as better water quality, increased water yield, soil health, reduced erosion and habitat connectivity. These policies and co-benefits will be considered as part of the integrated strategy outlined above.

The four concepts below illustrate how many of the policies that will be included in any preferred path to achieving the 2030 target are already known. Some of the concepts do allow for modifying those existing or draft policies to address GHG emissions from a specific sector. Stakeholders are encouraged to provide comments on the high level concepts presented or alternative concepts, while keeping in mind that some of these are statutory requirements or existing and draft plans that have been under development for a while with a public process.

Concept 1: Complementary Policies with a Cap-and-Trade Program

Concept 1 would include enhancements to existing programs and implementation of SB 350. This concept builds on the successful programs that have put California on the path for reaching the 2020 GHG Statewide limit mandated by AB 32. This concept also continues California's strategy to rely on a package of complementary measures to achieve its GHG reduction goals as well several co-benefits including reduction of other pollutants that adversely impact public health particularly in disadvantaged communities where levels are frequently elevated. The major policies in this scenario would include the following 2030 goals:

- SB 350 – by 2030
    - 50 percent RPS
    - Doubling of energy efficiency of existing buildings
- Increase in Low Carbon Fuel Standard – by 2030
    - Carbon Intensity reduction: > 10%
- Mobile Source Strategy
    - 1.5 million zero emission and plug-in hybrid light duty electric vehicles by 2025
    - Medium and Heavy-Duty GHG Phase 2
    - Advanced Clean Transit: Up to 20 percent of new urban buses purchased beginning in 2018 will be zero-emission buses, ramping up to 100 percent of new sales in 2030.
    - Last Mile Delivery: Phase-in of zero-emission trucks for class 3-7 last mile delivery trucks starting in 2020. Zero-emission vehicles comprise 2.5 percent of new Class 3-7 trucks sales in local fleets starting 2020, increasing to 10 percent in 2025 and remaining flat through 2030.
- Implementation of currently proposed Short Lived Climate Pollutant Strategy – by 2030
    - 40% reduction in methane and hydrofluorocarbon emissions
    - 50% reduction in black carbon emissions
- Increased stringency of SB 375 Sustainable Communities Strategy – 2035 targets
- Draft California Sustainable Freight Action Plan
    - Deploy over 100,000 freight vehicles and equipment capable of zero emission operation and maximize near-zero emission freight vehicles and equipment powered by renewable energy by 2030.

- Cap-and-Trade Program with a 4 percent annual cap decline
- Natural and Working Lands – by 2030
    - Each year, 500,000 acres of nonfederal forest lands included in restoration plans oriented towards forest health and carbon storage
    - More infill and revitalization of urban core areas
    - Land preservation policies
    - Increase habitat acreage protected or restored

Concept 1 largely builds on California's success with existing programs to include enhancements to those programs combined with the new SB 350 requirements. The Low Carbon Fuel Standard would build on the current CI reduction of 10 percent in 2020 requiring further reductions in the CI through 2030. The comprehensive strategies for Sustainable Freight, Mobile Source, and California Transportation Plan 2040 that are recently developed or in the process of being finalized would be implemented to maximize benefits for criteria and air toxics and GHG reductions. This scenario would include increased stringency of SB 375 Sustainable Communities Strategy 2035 targets. To ensure that the State meets the 40% GHG reduction target, Concept 1 would include a Cap-and-Trade Program with declining caps to provide compliance flexibility for the regulated entities, access and incentive to identify the lowest cost GHG emission reduction opportunities across the economy.

This would also provide continued support for collaborative action through linkages with other programs, such as Québec's Cap-and-Trade System and a recently established Ontario Cap-and-Trade Program. We could also use the extended Cap-and-Trade Program for demonstrating compliance with the Clean Power Plan (CPP) without the need to make other programs, such as the RPS, subject to Federal jurisdiction. The Cap-and-Trade Program could also potentially be linked with other states that chose to pursue a trading program to comply with CPP. Importantly, as other sectors are identified for GHG emissions regulation at the federal level, the Cap-and-Trade Program can readily accommodate that expansion.

As Concept 1 includes the Cap-and-Trade Program with quarterly auctions of allowances, funds would also continue to be deposited into the GGRF. Currently, the Legislature and Governor appropriate proceeds from the sale of State-owned allowances for projects that support the goals of AB 32. Strategic investment of these proceeds furthers the goals of AB 32 by reducing GHG emissions, providing net GHG sequestration, providing co-benefits, and supporting the long-term, transformative efforts needed to improve public and

environmental health and develop a clean energy economy. These investments support programs and projects that also deliver major economic, environmental, and public health benefits for Californians, including meaningful benefits to the most disadvantaged communities. Investments are providing a multitude of benefits to disadvantaged communities including increased affordable housing opportunities, reduced transit and transportation costs, access to cleaner vehicles, improved mobility options and air quality, job creation, energy and water savings, and greener and more vibrant communities.

Concept 2: Ambitious Complementary Policies without Cap-and-Trade; a Focus on Industrial Sources

Concept 2 would include some additional enhancement of existing policies, implementation of SB 350, and industrial facility caps to specifically address the industrial sector. The major policies in this scenario would include the following goals:

- SB 350 – by 2030
  - 50 percent RPS
  - Doubling of energy efficiency of existing buildings
- Increase in Low Carbon Fuel Standard – by 2030
  - Carbon Intensity reduction: > 10%
- Mobile Source Strategy
  - 1.5 million zero emission and plug-in hybrid light duty electric vehicles by 2025.
  - Medium and Heavy-Duty GHG Phase 2
  - Advanced Clean Transit: Up to 20 percent of new urban buses purchased beginning in 2018 will be zero-emission buses, ramping up to 100 percent of new sales in 2030.
  - Last Mile Delivery: Phase-in of zero-emission trucks for class 3-7 last mile delivery trucks starting in 2020. Zero-emission vehicles comprise 2.5 percent of new Class 3-7 trucks sales in local fleets starting 2020, increasing to 10 percent in 2025 and remaining flat through 2030.
- Enhanced implementation of currently proposed Short Lived Climate Pollutant Strategy – by 2030
  - > 40% reduction in methane and hydrofluorocarbon emissions
  - > 50 % reduction in black carbon emissions
- More ambitious targets of SB 375 Sustainable Communities Strategy – 2035 targets

- Draft California Sustainable Freight Action Plan
    - Deploy over 100,000 freight vehicles and equipment capable of zero emission operation and maximize near-zero emission freight vehicles and equipment powered by renewable energy by 2030.
- Entity level GHG declining caps for industrial sources
- Natural and Working Lands – by 2030
    - Each year to 2030, 500,000 acres of nonfederal forest lands included in restoration plans oriented towards forest health and carbon storage
    - More infill and revitalization of urban core areas
    - Land preservation policies
    - Increase habitat acreage protected or restored

Concept 2 does not include a Cap-and-Trade Regulation post-2020 and thus would also require more ambitious targets for the Short Lived Climate Pollutant Strategy and more ambitious 2035 targets for SB 375 than in Concept 1. Because this scenario would not include a statewide limit on GHG emissions, continuous program adjustments may be necessary to ultimately achieve the 2030 target. Under Concept 2, there would be requirements on the industrial entities currently regulated by the Cap-and-Trade Program to each reduce their GHG emissions at a rate to be determined once there has been an evaluation of how many additional reductions are still needed after the other policies are implemented. The industrial facility caps would not decline at a rate greater than 4 percent each year. The industrial facility caps would be established by identifying a baseline annual GHG emissions level for each regulated entity in permits, and requiring a decrease in emissions to achieve the required GHG reductions. If the modeling demonstrates the 2030 target is still not achieved, other policies such as the Low Carbon Fuel Standard may need to be made more stringent.

Concept 2 would not include any type of compliance instruments or trading as is included in the Cap-and-Trade Program. The linked cap-and-trade program between California and Québec would no longer exist. We would also forgo future linkages with other programs. The State would also need to identify another program, such as facility caps, as the compliance demonstration mechanism for the CPP. And, as the federal GHG regulations are expanded to cover additional sectors, we would need to take a sector-by-sector approach to address compliance under a federal scheme.

Concept 3: Ambitious Complementary Policies without Cap-and-Trade; a Focus on Transportation

Concept 3 does not include a Cap-and-Trade Regulation post-2020 and thus would require additional focus on reducing GHG emissions from the transportation sector. The major policies in this scenario would include the following goals:

- SB 350 – by 2030
  - 50 percent RPS
  - Doubling of energy efficiency of existing buildings
- Increase in Low Carbon Fuel Standard – by 2030
  - Carbon Intensity reduction: >10%
- Mobile Source Strategy
  - 3.5-4.5 million zero emission and plug-in hybrid light duty electric vehicles by 2030
  - Medium and Heavy-Duty GHG Phase 2
  - Advanced Clean Transit: Up to 20 percent of new urban buses purchased beginning in 2018 will be zero-emission buses, ramping up to 100 percent of new sales in 2030.
  - Last Mile Delivery: Phase-in of zero-emission trucks for class 3-7 last mile delivery trucks starting in 2020. Zero-emission vehicles comprise 2.5 percent of new Class 3-7 trucks sales in local fleets starting 2020, increasing to 10 percent in 2025 and remaining flat through 2030.
- Implementation of currently proposed Short Lived Climate Pollutant Strategy – by 2030
  - 40% reduction in methane and hydrofluorocarbon emissions
  - 50% reduction in black carbon emissions
- Require industrial entities to evaluate and identify cost-effective and technically feasible improvements, develop individual rules on source types of emissions and require improvements during scheduled maintenance, or other schedule, at the industrial facility
- Ambitious stringency of SB 375 Sustainable Communities Strategy – 2035 targets
- Draft California Sustainable Freight Action Plan
  - Deploy over 100,000 freight vehicles and equipment capable of zero emission operation and maximize near-zero emission freight vehicles and equipment powered by renewable energy by 2030.
- Natural and Working Lands – by 2030

    - Each year, 500,000 acres of nonfederal forest lands included in restoration plans oriented towards forest health and carbon storage
    - More infill and revitalization of urban core areas
    - Ambitious land preservation policies
    - Increase habitat acreage protected or restored

Concept 3 would include more ambitious targets for the Low Carbon Fuel Standard and increased percentage of zero emission vehicles than in Concept 1. Because this scenario would not include a statewide limit on GHG emissions, continuous program adjustments may be necessary to ultimately achieve the 2030 target. As this strategy would focus on transportation and fuels, staff would explore additional measures to promote technology with GHG emissions reductions from heavy-duty vehicles, public transit systems, and freight. Industrial sector GHG emissions would be addressed through the traditional regulatory approach for addressing criteria pollutants at stationary sources. Land-use and planning would also include additional measures to reduce VMT by identifying more ambitious targets for SB 375 than in Concepts 1 and 2. Enhanced goals for the natural working lands sector for land preservation would support reduced new development and reduced VMT.

Concept 3 would not include any type of compliance instruments or trading as is included in the Cap-and-Trade Program. The existing linked cap-and-trade program between California and Québec would no longer exist. We would forgo future linkages of this type with other programs, such as the recently adopted Ontario Cap-and-Trade Program. The State would also need to identify another program, such as the RPS or use the facility level caps, as the compliance demonstration mechanism for the Clean Power Plan. And, as the federal GHG regulations are expanded to cover additional sectors, we would need to take a sector-by-sector approach to address compliance under a federal scheme.

Concept 4: Complementary Policies with a Carbon Tax

Concept 4 would include the same enhancements to existing programs as in Concept 1, but in lieu of a Cap-and-Trade Program, this scenario includes a carbon tax. The major policies in Concept 4 would include the following goals:

- SB 350 – by 2030
    - 50 percent RPS
    - Doubling of energy efficiency of existing buildings
- Increase in Low Carbon Fuel Standard – by 2030

    - Carbon Intensity reduction: > 10%
- Mobile Source Strategy
    - 1.5 million zero emission and plug-in hybrid light duty electric vehicles by 2025
    - Medium and Heavy-Duty GHG Phase 2
    - Advanced Clean Transit: Up to 20 percent of new urban buses purchased beginning in 2018 will be zero-emission buses, ramping up to 100 percent of new sales in 2030.
    - Last Mile Delivery: Phase-in of zero-emission trucks for class 3-7 last mile delivery trucks starting in 2020. Zero-emission vehicles comprise 2.5 percent of new Class 3-7 trucks sales in local fleets starting 2020, increasing to 10 percent in 2025 and remaining flat through 2030.
- Implementation of currently proposed Short Lived Climate Pollutant Strategy – by 2030
    - 40% reduction in methane and hydrofluorocarbon emissions
    - 50% reduction in black carbon emissions
- Increased stringency of SB 375 Sustainable Communities Strategy – 2035 targets
- Draft California Sustainable Freight Action Plan
    - Deploy over 100,000 freight vehicles and equipment capable of zero emission operation and maximize near-zero emission freight vehicles and equipment powered by renewable energy by 2030.
- Natural and Working Lands – by 2030
    - Each year, 500,000 acres of nonfederal forest lands included in restoration plans oriented towards forest health and carbon storage
    - More infill and revitalization of urban core areas
    - Land preservation policies
    - Increase habitat acreage protected or restored
- Carbon tax applied at a value predetermined by a method such as economic modeling or the use of the US EPA social cost of carbon

Concept 4 would require additional legislative authority, as it is a tax. Other GHG reductions policies can be implemented under existing authority. A potential carbon tax could be set at the same point of regulation for the entities that are currently subject to the California Cap-and-Trade Program, or farther upstream. Because this scenario would not include a statewide limit on GHG emissions, it is unknown if any given level carbon tax would ultimately achieve the 2030 target. This scenario includes a fixed cost for each metric ton of carbon dioxide equivalent, which could be priced at a value predetermined by a method such as economic modeling or the use of the US EPA social cost of carbon, which has a

range of $11 to $105 in 2015. At this time, it is not known how monies generated by a carbon tax would be used. Although some types of GGRF programs could continue to be funded, if a carbon tax is passed by a 2/3 vote, it would give the legislature and Governor more flexibility on ways to use the funds.

Under Concept 4, the linked cap-and-trade program between California and Québec would no longer exist. We would forgo future linkages of this type with other programs, such as the Ontario program and a federal trading system for the CPP. The State would need to identify another program, such as the RPS, as the compliance demonstration mechanism for the Clean Power Plan. And, as the federal GHG regulations are expanded to cover additional sectors, we would need to take a sector-by-sector approach to address compliance under a federal scheme.

Next Steps and Submittal of Public Comments

As part of the continuing public input process, ARB staff will provide a Draft Scoping Plan update at the June 23rd Board hearing, which will include the opportunity for public comment. This summer and fall, the agencies will hold public workshops to solicit comments on modeling efforts and scenarios for achieving the 2030 target. Once the scenarios are fully developed in late summer, we will provide a Draft Scoping Plan with CEQA and economic analyses for public review and comment.

The first Board hearing on the Draft Scoping Plan is planned for November 2016 with a second Board hearing in March 2017. The Environmental Advisory Justice Committee is also planning a series of local community meetings plus additional full Committee meetings throughout the State starting in summer 2016.

This paper provides the overall framing for this Draft Scoping Plan and lays out the challenge and potential solutions to achieving our 2030 statewide GHG target. For this paper, stakeholders are encouraged to provide written comments during an informal comment period which will conclude at 5:00 p.m. Pacific time on Friday, July 8, 2016. Comments can be submitted here: http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm

APPENDIX A

2030 Target Scoping Plan Concept Paper

Draft Reference Scenario Assumptions for PATHWAYS Model

DRAFT REFERENCE SCENARIO MAJOR POLICY ASSUMPTIONS
Utility Electricity - Supply Side
Renewable Portfolio Standard (RPS) - SB 1x-2: Achieve 33% by 2020 and maintain at 33% through 2050. Renewable generation technologies represented using the California Public Utilities Commission (CPUC) RPS Calculator (2016) SB 1368: Existing coal generation contracts expire and are not renewed Phase out of Once Through Cooling capacity as planned Increased Combined Heat and Power (CHP) to achieve the Governor's target as described in the CPUC Long-Term Procurement Plan (LTPP, February 2016) Energy storage requirements (CPUC) achieved and then maintained through 2050 Diablo Canyon retired in 2025
Buildings
The Integrated Energy Policy Report (IEPR, 2015) California Energy Demand Forecast is used as a benchmark through 2026, which incorporates: *Additional Achievable Energy Efficiency* *Continued Cap-and-Trade Program cap maintained at the 2020 level* *Customer Side Solar, including the Governor's Distributed Generation (DG) goal* *Building Energy Efficiency Standards (AB 1109, AB 1470)* *Green State Buildings Executive Order* *Energy Savings Assistance Program* *Weatherization Assistance Program*
Transportation
The Mobile Source Strategy (May 2016) Current Control Programs scenario is used, which is based on CARB Vision Scenario Planning analyses (Version 2.1). The Vision analyses incorporate: *AB1493 Clean Car Standards* *Advanced Clean Cars* *Zero Emissions Vehicle (ZEV) Action Plan (EO B-16-2012)* *Maritime: Ocean/Harbor Regulation* *High Speed Rail (SP T-9)* *SB99 Active Transport* *SB375 Sustainable Communities (current plans)* *Affordable housing and sustainable communities program* *Heavy Duty Vehicle (HDV) Efficiency Standards (EPA/NHTSA and SP T-8)*

DRAFT REFERENCE SCENARIO MAJOR POLICY ASSUMPTIONS
Fuels
Low Carbon Fuel Standard (LCFS) achieves 10% reduction in fuel carbon intensity (CI) by 2020 (relying in part on banked credits) and maintains the 10% thereafter. The LCFS analysis incorporates the continuation of the Federal Renewable Fuel Standard and the Cap-and-Trade Program cap maintained at the 2020 level. (The Federal Biodiesel Blenders Tax Credit is assumed to end after 2016.)
Industry and Agriculture Energy Demand
The Integrated Energy Policy Report (IEPR, 2015) California Energy Demand Forecast is used as a benchmark through 2026, which incorporates: *Additional Achievable Energy Efficiency* *Continued Cap-and-Trade Program cap maintained at the 2020 level*
Non-energy, non-CO_2 Greenhouse Gases
The Proposed Short Lived Climate Pollutant Strategy (April 2016) is used, reflecting emissions estimates with existing measures.

Carbon Dioxide Emissions

Please click on the column title to reorder.

No	Plant Name	Country	State /Province	Primary Fuel	Electricity Generation (MWh)	Emission Rate (kg/MW-h)	Total Emissions (t)
1201	Highland	United States	Illinois	Oil	1,870.95	750.83	1,404.77
1202	Highmore	United States	South Dakota	Oil	256.95	882.78	226.83
1203	Hill City	United States	Kansas	Natural Gas	1,631.89	648.96	1,059.03
1204	Hillburn	United States	New York	Natural Gas	689.89	1,419.52	979.31
1205	Hillsdale	United States	Michigan	Natural Gas	1,398.92	625.77	875.41
1206	Hilton Head	United States	South Carolina	Oil	1,204.94	2,682.33	3,232.04
1207	Hines Energy Complex	United States	Florida	Natural Gas	6,071,853.00	378.23	2,296,585.74
1208	HMP&L Station Two Henderson	United States	Kentucky	Coal	1,434,960.00	1,596.01	2,290,214.40
1209	Hoffer Plastics	United States	Illinois	Natural Gas	11,628.92	611.68	7,113.19
1210	Hoffmann LaRoche	United States	New Jersey	Natural Gas	62,037.80	452.91	28,097.24
1211	Hofstra University	United States	New York	Natural Gas	12,734.97	478.47	6,093.27
1212	Hog Bayou Energy Center	United States	Alabama	Natural Gas	20,103.00	382.45	7,688.45
1213	Hoisington	United States	Kansas	Natural Gas	1,169.88	577.90	676.07

DOWNLOAD THE REPORT

Download the report by clicking on the image. You can also view maps and explore the data using Google Earth or download the raw data in excel format.

RESOURCES

Project Glossary

Related Websites

USEFUL CONVERSION TABLES

Energy				
Basic Unit	Joule	J		
Electricity consumption	Watt-hour	Wh	3600	J
British units system	British thermal unit	Btu	1,055.056	J
Mass				
Basic Unit	gram	g		
Metric tonne	tonne	t	1,000,000	g
Power				
Basic Unit	Watt	W	1	J/s

Common Unit Prefixes		multiply by
k	kilo	$1x10^3$
M	mega	$1x10^6$
G	giga	$1x10^9$
T	tera	$1x10^{12}$
Global Warming Potential		**CO_2 Equivalent**
CO_2	Carbon dioxide	1
CH_4	Methane	21

No	Plant Name	Country	State /Province	Primary Fuel	Electricity Generation (MWh)	Emission Rate (kg/MW-h)	Total Emissions (t)
1214	Holcomb	United States	Kansas	Coal	2,684,906.00	946.72	2,541,861.19
1215	Holden	United States	Missouri	Natural Gas	25,545.00	708.86	18,107.83
1216	Holland Energy Facility	United States	Illinois	Natural Gas	827,075.00	426.92	353,094.83
1217	Holly	United States	Colorado	Oil	16.95	750.97	12.73
1218	Holly Street	United States	Texas	Natural Gas	377,352.00	638.06	240,772.77
1219	Holton	United States	Kansas	Natural Gas	3,785.94	564.93	2,138.79
1220	Holtsville	United States	New York	Oil	135,220.00	1,043.18	141,058.30
1221	Homer City Station	United States	Pennsylvania	Coal	13,599,227.00	894.51	12,164,632.72
1222	Honea Path	United States	South Carolina	Oil	36.95	768.01	28.38
1223	Honeywell Farms	United States	New York	Natural Gas	12,126.44	453.20	5,495.67
1224	Honolulu	United States	Hawaii	Oil	191,897.96	915.90	175,760.04
1225	Hoonah	United States	Alaska	Oil	5,116.96	701.88	3,591.47
1226	Hooper Bay	United States	Alaska	Oil	2,432.94	775.19	1,885.99
1227	Hoot Lake	United States	Minnesota	Coal	934,548.00	1,123.32	1,049,795.87
1228	Hoover Company	United States	Texas	Oil	146.93	513.26	75.41
1229	Hopewell Cogeneration	United States	Virginia	Natural Gas	691,707.84	508.32	351,611.73
1230	Hopkinton	United States	Iowa	Oil	41.93	860.08	36.06
1231	Horseshoe Lake	United States	Oklahoma	Natural Gas	698,429.00	683.18	477,150.94
1232	Hot Spring Power Project	United States	Arkansas	Natural Gas	452,428.94	432.54	195,694.74
1233	Houma	United States	Louisiana	Natural Gas	52,783.95	835.34	44,092.59

N_2O	Nitrous oxide	310

No	Plant Name	Country	State /Province	Primary Fuel	Electricity Generation (MWh)	Emission Rate (kg/MW-h)	Total Emissions (t)
1234	Houston Chemical Complex Battleground	United States	Texas	Natural Gas	1,395,962.81	12.39	17,297.28
1235	Howard Bend	United States	Missouri	Oil	196.94	883.27	173.95
1236	Howard Down	United States	New Jersey	Coal	95,329.83	1,261.43	120,252.33
1237	Hudson Avenue	United States	New York	Oil	2,555.94	1,338.56	3,421.29
1238	Hugo	United States	Oklahoma	Coal	3,019,097.00	1,050.95	3,172,908.75
1239	Hugoton 2	United States	Kansas	Natural Gas	2,052.89	650.75	1,335.92
1240	Humboldt Bay	United States	California	Natural Gas	444,498.00	674.90	299,992.00
1241	Hunlock Power Station	United States	Pennsylvania	Coal	236,042.77	1,346.02	317,718.50
1242	Hunter	United States	Utah	Coal	9,742,633.00	976.15	9,510,226.36
1243	Hunterdon Cogen Facility	United States	New Jersey	Natural Gas	26,749.96	650.20	17,392.79
1244	Hunters Point	United States	California	Natural Gas	619,481.00	609.37	377,491.42
1245	Hunterstown	United States	Pennsylvania	Natural Gas	714,682.00	419.28	299,653.60
1246	Hunterstown	United States	Pennsylvania	Natural Gas	8,004.88	912.35	7,303.23
1247	Huntington	United States	Utah	Coal	6,381,332.00	905.83	5,780,425.43
1248	Huron	United States	South Dakota	Natural Gas	124.94	8,573.89	1,071.22
1249	Hutchinson Energy Center	United States	Kansas	Oil	183,240.00	1,017.43	186,433.10
1250	Hutchinson Plant #1	United States	Minnesota	Oil	1,452.85	591.32	859.11

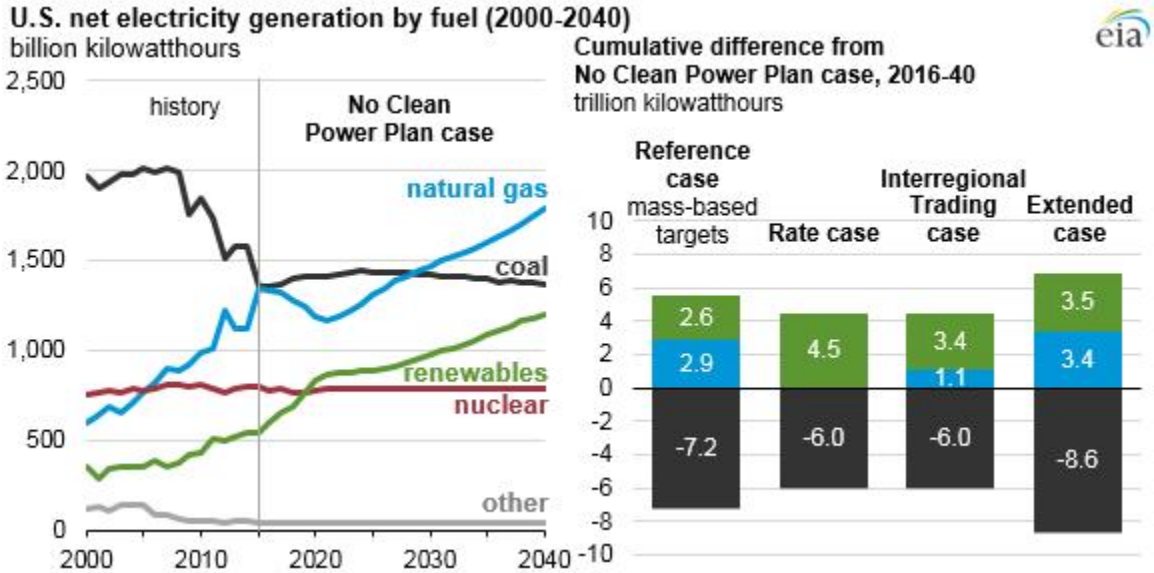
« first ‹ previous … 21 22 23 24 25 26 27 28 29 … next › last »

U.S. Energy Information Administration

Today in Energy

Jul 6, 2016

Clean Power Plan implementation choices by states could affect electricity generation mix



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2016*

In designing the Clean Power Plan, the U.S. Environmental Protection Agency provided states with implementation flexibility. Given the options available to states, EIA has produced several scenarios as part of an Issues in Focus analysis in the *Annual Energy Outlook 2016* (AEO2016). Differences in emissions target types, emissions trading markets, and policy timelines have implications for electric capacity and generation in the United States.

Read More ›

Tags: AEO2016 (Annual Energy Outlook 2016) , Clean Power Plan (CPP) , CO2 (carbon dioxide) , coal , electricity , electricity generating fuel mix , energy efficiency , forecast , natural gas , renewable , solar , wind

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Jul 5, 2016

Mexico electricity market reforms attempt to reduce costs and develop new capacity

Source: EIA calculations based on locational marginal price data from Mexico CENACE using an exchange rate of 0.054 U.S. dollars per Mexican peso
Note: Locations of load zones on map are approximate.

Mexico is in the process of reforming much of its electricity industry. Earlier in 2016, Mexico opened up day-ahead and real-time trading in a new wholesale power market. Although wholesale prices briefly spiked for a handful of hours, average prices in most locations during the market's first six months of operation have ranged from 880 to 1,100 pesos per megawatthour (MWh), or about $48/MWh to $60/MWh.

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Tags: electricity , generation , international , Mexico , policy , prices , renewable , wholesale prices

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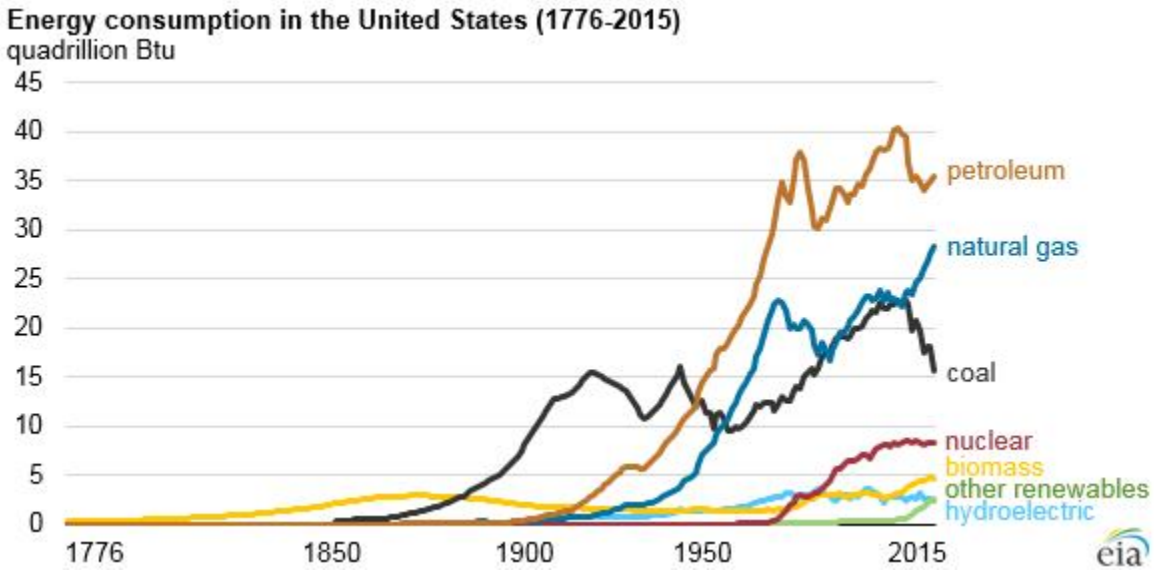
Jul 1, 2016

Fossil fuels still dominate U.S. energy consumption despite recent market share decline



Source: U.S. Energy Information Administration, *Monthly Energy Review*

Three fossil fuels—petroleum, natural gas, and coal—have provided more than 80% of total U.S. energy consumption for more than 100 years. In 2015, fossil fuels made up 81.5% of total U.S. energy consumption, the lowest fossil fuel share in the past century. In EIA's *Annual Energy Outlook 2016* Reference case projections, which reflect current laws and policies, that percentage declines to 76.6% by 2040. Policy changes or technology breakthroughs that go beyond the trend improvements included in the Reference case could significantly change that projection.

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Tags: biomass , coal , consumption , hydroelectric , liquid fuels , natural gas , nuclear , oil/petroleum , renewable

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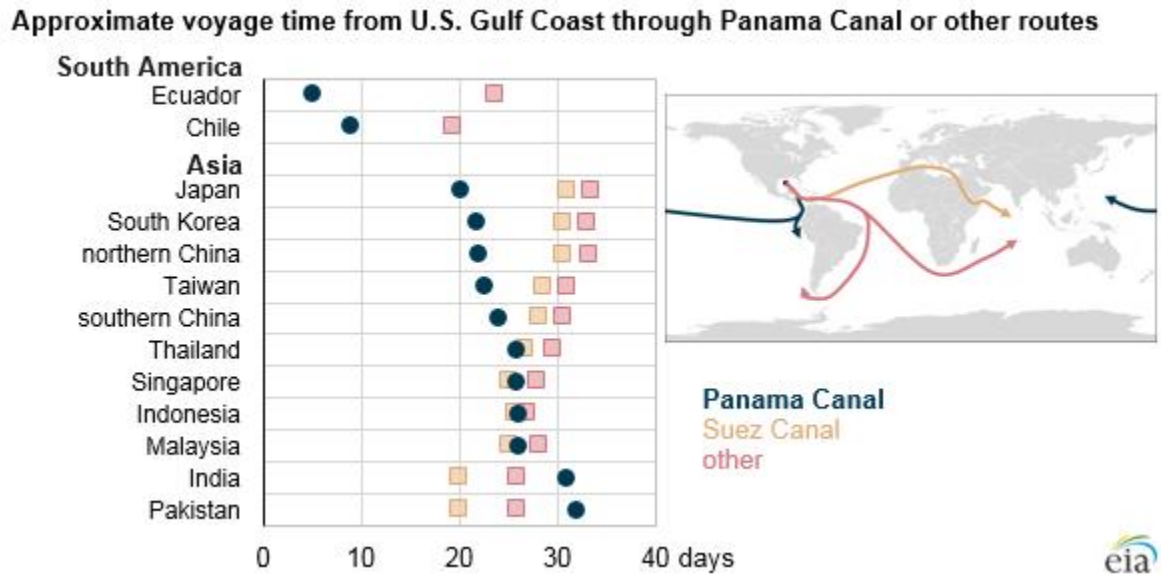
Jun 30, 2016

Expanded Panama Canal reduces travel time for shipments of U.S. LNG to Asian markets



Source: U.S. Energy Information Administration calculations based on IHS and other sources
Note: Calculations assume export from the Sabine Pass liquefaction terminal at an average LNG Carrier speed of 19.5 knots and one-day transit time through the Panama and Suez Canals.

The newly expanded Panama Canal will be able to accommodate 90% of the world's current liquefied natural gas (LNG) tankers with LNG-carrying capacity up to 3.9 billion cubic feet (Bcf). Prior to the expansion, only 30 of the smallest LNG tankers (6% of the current global fleet) with capacities up to 0.7 Bcf could transit the canal. The expansion has significant implications for LNG trade, reducing travel time and transportation costs for LNG shipments from the U.S. Gulf Coast to key markets in Asia and providing additional access to previously regionalized LNG markets.

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Tags: liquid fuels , LNG (liquefied natural gas) , natural gas , transportation

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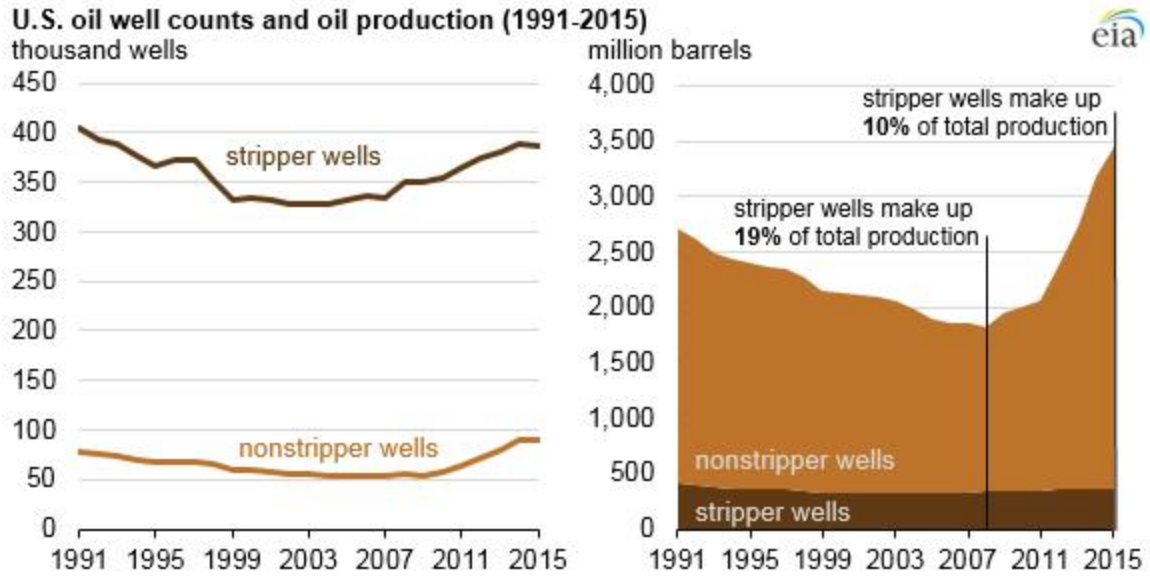
Jun 29, 2016

Stripper wells accounted for 10% of U.S. oil production in 2015



Source: U.S. Energy Information Administration, based on DrillingInfo
Note: Results can vary because of the types of wells, completions, and leases included in the analysis, update schedules of source databases, and estimation results for a number of late-reporting states.

Stripper wells, or wells that produce small volumes, represent an important but decreasing share of total U.S. oil and natural gas production. These wells are characterized as producing no more than 15 barrels of oil equivalent per day (boe/d) over a 12-month period. EIA estimates that there were about 380,000 stripper oil wells (so called because they are stripping the remaining oil out of the ground) in the United States operating at the end of 2015, compared to about 90,000 nonstripper oil wells.

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Tags: liquid fuels , oil/petroleum , production

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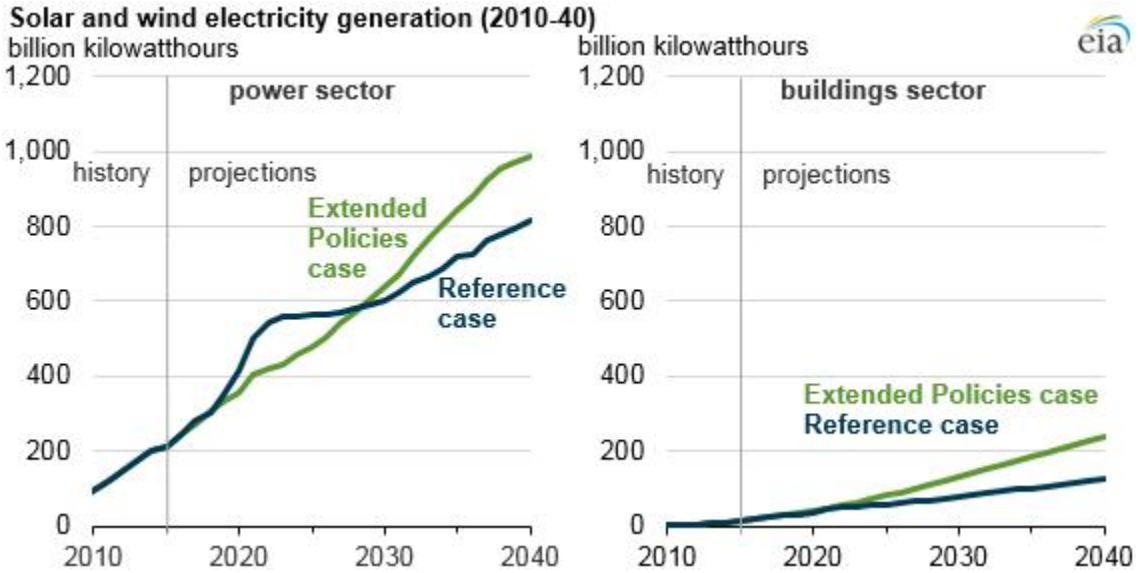
Jun 28, 2016

Extended policies case shows reduced energy use, emissions, more renewables, efficiency



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2016*

Tax credits and efficiency standards for appliances and vehicles have been key drivers for increasing renewable energy use and

energy efficiency in the United States. Extending these policies and increasing the stringency of the Clean Power Plan beyond 2030 would reduce energy-related carbon dioxide (CO2) emissions by reducing motor fuel use and energy use in buildings by increasing efficiency and by increasing the share of solar and wind in the electricity generation mix.

Read More ›

Tags: AEO2016 (Annual Energy Outlook 2016) , efficiency , electricity , emissions , forecast , solar , standards , wind

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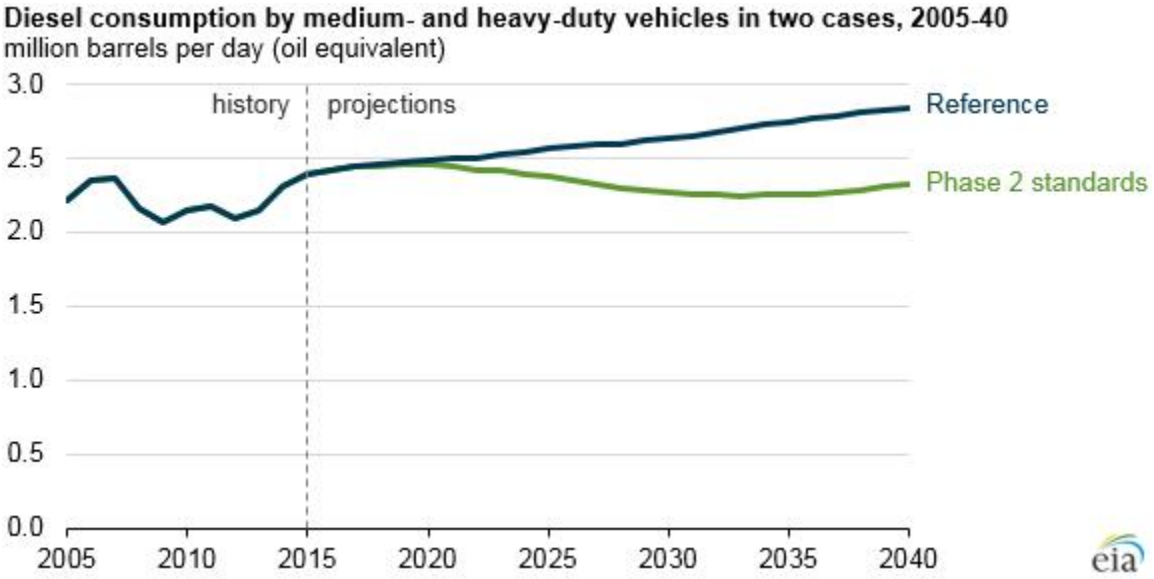
Jun 27, 2016

Proposed standards for medium- and heavy-duty vehicles would reduce diesel consumption



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2016*

Proposed fuel economy and greenhouse gas emissions standards would increase fuel economy and reduce diesel consumption in medium- and heavy-duty vehicles. Unlike light-duty vehicles, which have been subject to fuel economy standards since the 1970s, the first phase of medium- and heavy-duty vehicle standards was recently implemented, starting with model year 2014. The proposed Phase 2 standards—issued jointly by the U.S. Environmental Protection Agency and the National Highway Traffic Safety Administration—would take effect in model year 2021 for most medium- and heavy-duty vehicle classes and increase in stringency through model year 2027. These standards are projected to reduce diesel consumption by 0.5 million barrels of oil equivalent per day (boe/d) by 2040.

Read More ›

Tags: AEO2016 (Annual Energy Outlook 2016) , diesel , gasoline , transportation

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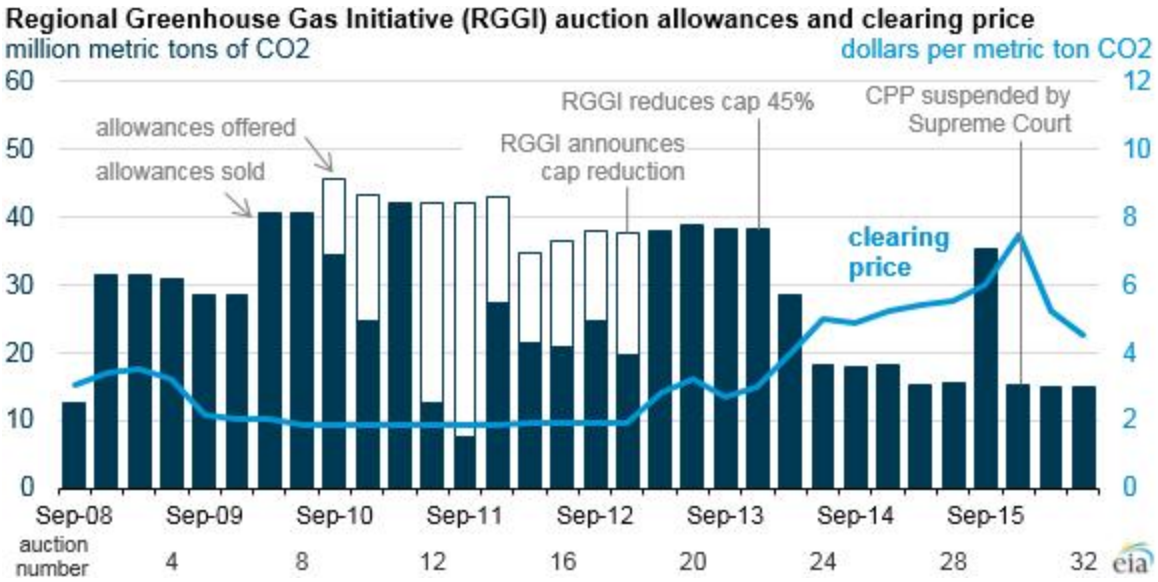
Jun 24, 2016

Regional Greenhouse Gas Initiative auction prices decline



Source: U.S. Energy Information Administration, based on Regional Greenhouse Gas Initiative

Prices of carbon dioxide (CO2) emission allowances in the Regional Greenhouse Gas Initiative (RGGI) have fallen for the second auction in a row, to $4.53 per metric ton (mt) of CO2. The auction prices on June 1 were 40% below their previous peak value of $7.50/mtCO2, reached on December 2, 2015.

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Tags: CO2 (carbon dioxide) , electricity , emissions , generation

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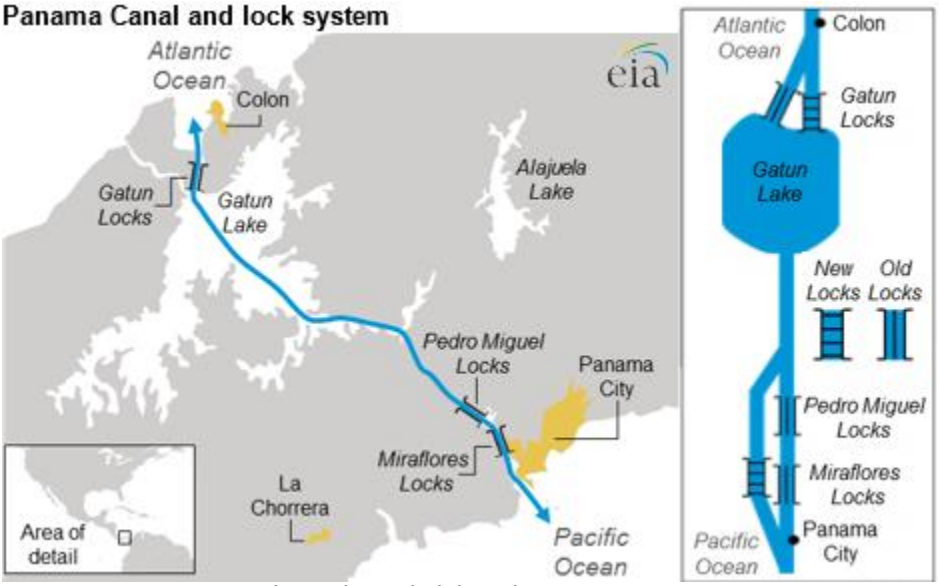
Jun 23, 2016

Panama Canal expansion unlikely to significantly change crude oil, petroleum product flows



Source: U.S. Energy Information Administration

On June 26, the Panama Canal Authority, the body that operates the Panama Canal, will inaugurate a third set of locks, which will allow for the transit of larger ships. This is the first such expansion since the canal was completed in 1914. With the exception of U.S. propane exports, the expansion of the Panama Canal is not likely to drastically affect crude oil and petroleum product flows.

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Tags: crude oil , liquid fuels , propane , transportation

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Jun 22, 2016

U.S. crude oil storage capacity utilization rises even as storage capacity grows

Source: U.S. Energy Information Administration, *Weekly Petroleum Status Report*

Weekly U.S. commercial crude oil inventories have increased by more than 71 million barrels (15%) since the end of September, pushing crude oil storage capacity utilization to a near record high of 73% for the week ending June 10.

Read More ›

Tags: capacity , crude oil , Cushing , liquid fuels , storage

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Sierra Club Data Request 1.26

Does the Hunter CSA, as amended, provide any protections for the Company and its customers with respect to existing or new environmental regulations? Please describe such provisions.

Response to Sierra Club Data Request 1.26

The Company objects to this request as requiring a legal opinion or the disclosure of information protected by the attorney-client privilege or attorney work product privilege. Without waiving these objections, the Company responds as follows:

The Hunter CSA Fifth Amendment does not specifically address the effect of existing or new environmental regulations.

1407 WEST NORTH TEMPLE, SUITE 210 • SALT LAKE CITY, UTAH 84116 • (801) 220-4581 • FAX (801) 220-4725

March 14, 2016

Submitted via email and electronically to www.regulations.gov

Gail Fallon
Director, Air Program
U.S. EPA, Region 8
Mailcode 8P-AR
1595 Wynkop Street
Denver, Colorado 80202-1129
Email:Fall.Gail@epa.gov

Re: Docket ID No. EPA-R08-OAR-2015-0463
Approval, Disapproval and Promulgation of Air Quality Implementations Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; State of Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze (Docket ID No. EPA-R08-OAR-2015-0463)("Proposed Rule")

Dear Ms. Fallon,

PacifiCorp appreciates the opportunity to offer these comments (including the extended comments, attachments and exhibits) in the above matter. PacifiCorp strongly encourages EPA to approve Utah's BART Alternative, thereby guaranteeing "reasonable progress" towards Utah's regional haze goals in a cost-effective manner. Utah's BART Alternative meets all "applicable requirements" of the Clean Air Act; therefore it should be approved by EPA. PacifiCorp strongly opposes EPA's proposed federal implementation plan, which would result in hundreds of millions of dollars in costs with less "reasonable progress" than the BART Alternative.

Because of the length of PacifiCorp's expanded comments, we have summarized for emphasis some of those comments as follows. The below summary is not intended to be a summation of PacifiCorp's expanded comments; those stand on their own in their complete form. Rather, this summary is provided as a convenience and as part of our overall comments.

UTAH'S SIP PROPOSAL SATIFIES THE REGIONAL HAZE REQUIREMENTS AND SHOULD BE APPROVED

- *Utah's SIP Proposal meets all applicable requirements.* Through proper application of each applicable requirement in the regional haze rules, Utah determined – and so did EPA –that the weight of the evidence demonstrates that the Utah SIP Proposal makes greater reasonable progress than installation and operation of BART; and it does so at a substantially lower cost.

- *EPA arbitrarily refuses to consider the dramatic cost difference between the two co-proposals.* EPA has made clear that the BART Alternative program is intended to achieve greater visibility progress in the most cost-effective manner. The Utah SIP does just that. EPA, however, refused to consider the cost savings associated with the Utah SIP proposal. This not only violates the foundational premise of its own BART alternative rule, but it also violates one of the fundamental tenets of reasonable regulation.

- *EPA should evaluate all visibility metrics under the weight of the evidence test.* Although EPA does an adequate job in identifying and weighing most of the available metrics, data and information under its weight of evidence analysis, it gives far too much weight to certain metrics (like the 98th Percentile metric) and not enough to other metrics (like cost and the timing of emission reductions under the BART Alternative analysis). By properly considering evidence, data and information and assigning the proper weight to each, EPA's approval of the Utah SIP Proposal will become even stronger.

- *EPA arbitrarily and capriciously applies two inappropriate standards to the Utah SIP Proposal.* In an attempt to replace Utah's determination with its own, EPA imposes a "Reasonableness Standard" without concluding the Utah SIP Proposal contains data or methodological flaws – the limited circumstances under which courts have upheld use of this standard – and also imposes a "Complexity of Evaluation" standard which finds no support in the CAA or applicable regulations.

- *EPA unfairly minimizes the timing of emissions reductions.* EPA glosses over the benefits of the timing of the BART Alternative emissions reductions. The emissions reductions associated with the BART Alternative began in 2007 and have continued to this day, long before any emissions reductions would occur under the FIP Proposal. Further, by attempting to impose BART controls EPA is actually requiring both the BART Alternative and BART – reaching well beyond the scope of its authority.

EPA's FIP PROPOSAL IS NOT LEGALLY SUSTAINABLE

- *Illegal treatment of existing controls.* EPA failed to properly consider existing controls by calculating a baseline emissions rate that did not include previously installed combustion

controls. This flawed baseline emissions rate led to incorrect and inflated cost and visibility data that EPA cannot rely on to implement its FIP Proposal.

- *Grossly flawed analysis of cost.* EPA's cost analysis is wrong for the numerous reasons, including the following: (1) it utterly fails to provide *any* rationale for the 70 million dollar difference between its cost estimate for SCR and PacifiCorp's cost estimate for SCR; (2) EPA failed to follow its own the Cost Control Manual – one that EPA has compulsively required utilities' to use – by disallowing material costs that are specifically included and allowed by the CCM. Finally, EPA's expert inexplicably and incorrectly redesigned the SCR technology – without any engineering support – to "show" that only one reactor is necessary instead of two and that less catalyst could be used, thereby further skewing the SCR cost analysis.

- *Improper accounting of Energy and Non-Air Quality Impacts*. EPA did not identify or quantify the solid, liquid, and gaseous discharges from the SCR control devices under review, or the discharges with potential for causing adverse environmental effects. Also, EPA should have considered multiple energy impacts of installing SCR, but it did not. These impacts are supposed to carry greater weight in situations like the one at hand, where the visibility improvement of a particular option is marginal at best.

- *Visibility Improvements.* The visibility improvements of EPA's FIP Proposal are not reasonably anticipated from the installation of SCR because (1) EPA failed to account for the margin of error in the CALPUFF model and other material limitations of CALPUFF; (2) EPA summed up the per unit improvements rather than modeling all four BART units together; and (3) EPA failed to properly account for the limited impact of additional NOX reductions.

Again, the above summary is provided only as a tool of convenience in regard to PacifiCorp's overall comments. Please feel free to contact me with any questions.

Sincerely,

William K. Lawson

Docket ID No. EPA-R08-OAR-2015-0463

PacifiCorp's Expanded Comments to: **Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze**

PacifiCorp provides these comments in response to the above proposed action by the U.S. Environmental Protection Agency ("**EPA**") as published in the Federal Register January 14, 2016 at 81 FR 2004 ("**Proposed Action**").[1]

I. INTRODUCTION

PacifiCorp, which operates in Utah under the business name Rocky Mountain Power, supplies electricity to more than 1.8 million residential and business customers in the state of Utah and five other western states. PacifiCorp is the majority owner and operator of Hunter Units 1 and 2, and is the owner and operator of Huntington Units 1 and 2 (collectively "**Utah BART Units**"). The Utah BART Units are the only sources that Utah and EPA have determined to be subject to the Clean Air Act's ("**CAA**") Best Available Retrofit Technology ("**BART**") requirements. As a result, PacifiCorp and its customers will be directly affected by EPA's final action regarding Utah's regional haze state implementation plan. The Utah regional haze state implementation plan, and all supporting documents, collectively are referred to herein as the "**Utah SIP**".

With regard to NOx emissions, EPA describes its Proposed Action as two "co-proposals" and further describes those as "A proposal to approve the State SIP in its entirety, and a proposal to partially approve and partially disapprove the State SIP and propose a FIP." See 81 FR at 2006. PacifiCorp refers to the "proposal to approve the State SIP in its entirety" as the "**SIP Proposal**," and the "proposal to partially approve and partially disapprove the State SIP and propose a FIP" as the "**FIP Proposal**."

PacifiCorp supports EPA's approval of the SIP Proposal because the Utah SIP satisfies the regional haze requirements as EPA itself has proposed to conclude. This conclusion should be the beginning and the end of EPA's final action. The SIP Proposal produces better visibility improvement under every metric (except one) and does so at cost savings of over $700 million[2] compared to the FIP Proposal. In addition, the single metric EPA

[1] These comments are in addition to those offered during the public hearing sponsored by EPA on January 26, 2016. A copy of the hearing comments are included at EPA-R08-OAR-2015-0463-0112 and identified as "Bill Lawson, Rocky Mountain Power."

[2] As explained below, adding LNB/OFA/SCR to the Utah BART Units will cost approximately $170 million for each unit, with the total for all four Utah BART Units

asserts shows better visibility improvement under the FIP Proposal (98th Percentile metric) should be afforded little or no weight in evaluating the SIP Proposal. Utah considered all of the applicable metrics and evidence and, under the weight-of-evidence analysis, easily determined that the BART Alternative produces greater reasonable progress than the BART Benchmark[3] at the Utah BART Units. Similarly, under the Proposed Action, EPA has a choice in evaluating the Utah SIP of approving one option (the SIP Proposal) with more visibility improvements at a substantially lower cost, or approving the other option (the FIP Proposal) with lower visibility improvements at a substantially higher cost. The choice is obvious. EPA should finalize its SIP Proposal and approve the Utah SIP.

PacifiCorp opposes the FIP Proposal because: (i) EPA has not provided adequate justification to conduct a new BART analysis for NOx while simultaneously proposing to conclude that the Utah SIP meets applicable regional haze requirements; and (ii) EPA's proposed BART analysis for each Unit is flawed, making the FIP Proposal legally unsustainable. In addition, EPA is not empowered under the CAA to require compliance with both the SIP Proposal and the FIP Proposal. As a practical matter, that is precisely what EPA proposes to do to the extent it approves the FIP Proposal. This is because PacifiCorp already has implemented the SIP Proposal as required by Utah law. If EPA were to select the FIP Proposal, it would do so knowing[4] that PacifiCorp would be required to implement <u>both</u> the SIP Proposal and the FIP Proposal. Nothing in CAA or

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exceeding $700 million. By contrast, EPA incorrectly asserts that the cost of LNB/OFA/SCR at each Utah BART Unit is about $110 million.

[3] According to EPA, the term "BART Benchmark" means "an analysis of the best system of continuous emission control technology available and the associated reductions for each source subject-to-BART covered by the alternative program…." See 81 FR at 2011. EPA sometimes uses this term in the FIP Proposal to mean requiring LNB, OFA and SCR as BART for NOx at each of the Utah BART Units, and without conceding EPA is correct, PacifiCorp refers to BART Benchmark herein in the same manner.

[4] EPA is well aware that the Utah SIP, as it has been implemented over time, became binding state law in regard to the Utah BART Units and ultimately the other units covered by the BART Alternative. This makes it particularly egregious that, even though EPA knew that PacifiCorp was required to expend hundreds of millions of dollars to fully implement the BART Alternative under state law, EPA said nothing about its intention to issue a competing co-proposal until after PacifiCorp had completed all of the emission reductions required under the Utah SIP. See EPA letter to Utah Division of Air Quality dated May 1, 2015 commenting on the then-proposed Utah SIP (including the BART Alternative). This secretive approach by EPA also caught the Utah Division of Air Quality off guard as explained in their oral comments during the January 26, 2016 hearing: "Throughout the SIP development process, we worked as regulatory partners, closely and extensively with EPA staff to ensure that Utah's Alternative to BART SIP revision met all the requirements of the Clean Air Act and was approvable by EPA. The EPA should approve the option that Utah developed while in close consultation with EPA and not the option that Utah was not even aware was being prepared or under consideration until it was proposed in the Federal Register."

regional haze rules allows EPA to require such a result when the Proposed Action itself states that EPA it "intends to finalize only one proposal." See 81 FR at 2006.

II. THE BART ALTERNATIVE DESERVES EPA APPROVAL

At least three different sources document that the SIP Proposal satisfies applicable regional haze requirements: (i) the Utah SIP; (ii) PacifiCorp's comments filed with the state of Utah in support of the Utah SIP (which comments are attached hereto as Attachment 1 and incorporated herein by this reference); and (iii) EPA's SIP Proposal. In general, EPA must approve any SIP, including the Utah SIP, that "meets all of the applicable requirements" of the CAA. See 42 U.S.C. 7410(k)(3). By the same token, EPA is prohibited from imposing additional requirements upon its approval/disapproval of a SIP that do not qualify as "applicable requirements." The applicable requirements that the Utah SIP must meet are described below. Also described are certain requirements that EPA purports to apply in evaluating the Utah SIP, but shouldn't, because they are not applicable requirements of the CAA.

A. Applicable BART Alternative Requirements

The Proposed Action properly describes the Utah SIP as "an alternative to BART" for NOx ("**BART Alternative**") that Utah adopted "instead of establishing BART controls" at the Utah BART Units. See 81 FR at 2006. The Proposed Action further describes EPA's support for BART alternative plans in general by noting that "the idea of a BART alternative…is a reasonable one, and one that EPA supports where consistent with the CAA and [regional haze requirements]." *Id.* In other words, as long as the BART Alternative complies with the CAA and applicable regional haze requirements, EPA is required to accept this approach in lieu of a BART determination.[5]

The Proposed Action also properly describes the evaluation (found generally at 40 C.F.R. 51.308(e)(2)) that EPA must conduct to decide whether to approve the BART Alternative as contained in the Utah SIP:

> "(1) '[a] demonstration that the emissions trading program or other alternative measure will achieve greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART in the State and covered by the alternative program'; (2) '[a] requirement that all necessary emission reductions take place during the period of the first long-term strategy for regional haze'; and (3) '[a] demonstration that the emissions reductions resulting from the alternative

[5] Comments that oppose any use of a BART alternative, like those found in Section I of the "July 8, 2015 Conservation Group Letter to EPA Janet McCabe" (EPA ID No. EPA-R08-OAR-2015-0463-0029) (the "**July 8th Letter**"), are not relevant to the issue of whether the BART Alternative meets applicable requirements. EPA should disregard such comments.

> measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP.'" See 81 FR at 2006.

EPA also properly describes applicable requirements (found generally at 40 C.F.R. 51.308(e)(2) and (3)) for use in determining whether the BART Alternative achieves greater reasonable progress:

> "For the first element, the determination that the alternative measure will achieve greater reasonable progress than BART, the State must provide the following: (1) A list of all BART-eligible sources within the State; (2) a list of all BART-eligible sources and all BART source categories covered by the alternative program; (3) an analysis of BART and associated emission reductions; (4) an analysis of the projected emission reductions achievable through the BART alternative; and (5) a determination that the alternative achieves greater reasonable progress than would be achievable through the installation and operation of BART." See 81 FR at 2006.

In addition, 40 C.F.R. 51.308(e)(2) makes clear that it is fully within a ***state's*** discretion whether to adopt a BART Alternative. That is, a "State may opt to implement or require participation in an…other alternative measure [i.e., BART Alternative] rather than require sources subject to BART to install, operate and maintain BART."[6] The CAA and the preamble to the BART Alternative rules also make clear that the elements of cost and energy/non-air quality impacts should be considered in the greater reasonable progress analysis. In taking final action, EPA should rely on the above requirements (which together are referred to as the "**Applicable BART Alternative Requirements**") and approve the Utah SIP.

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[6] Because of this, arguments that Utah should never have considered a BART Alternative are beyond the scope of the Proposed Action and are not relevant. For example, see Section II of the July 8th Letter which argues against the discretion used by Utah in deciding to select a BART Alternative including the following assertions, among others: (i) "Utah eschewed the cost-effective benefits of SCR in favor of a BART 'alternative'… that would require no new emission reductions on any source in the state;" (ii) the Units will "…continue to emit NOx at current high levels while taking credit for emissions reductions that already have occurred;" and (iii) EPA has "never used an alternative program to exempt all of the state's BART units from controls in exchange for wholly past emissions reductions at non-BART units." These assertions do not attempt to explain why the Utah SIP does not meet applicable regional haze requirements and are nothing more than arguing that Utah should never select any BART Alternative. EPA should disregard such comments.

B. <u>The Utah SIP Meets the Applicable BART Alternative Requirements</u>

The following table demonstrates that the BART Alternative meets the Applicable BART Alternative Requirements. Very simply, the table lists the Applicable BART Alternative Requirements in the two left-hand columns, and then notes in the two right-hand columns those parts of the Utah SIP that demonstrate compliance with each requirement. EPA is not required to apply any more complicated analysis than this in approving the BART Alternative under the Utah SIP.

Regulation	Summary	Utah SIP	SIP Proposal
308(e)(2)(i)(A)	List all BART eligible sources	**Meets requirement**: 2015 Utah RH SIP, Sec. XX.D.6 (a)-(e).	**Meets requirement**: 81 FR at 2015, 2021
308(e)(2)(i)(B)	List BART eligible sources covered by BART Alternative	**Meets requirement**: 2015 Utah RH SIP, Sec. XX.D.6 (a)-(e).	**Meets requirement**: 81 FR at 2015, 2021
308(e)(2)(i)(C)	Compare BART Alternative To BART	**Meets requirement**: 2015 Utah RH SIP at XX.D.6(c) (including TSD "Staff Review" dated May 13, 2015)	**Meets requirement**: 81 FR at 2015, 2021
308(e)(2)(i)(D)	Project emission reductions	**Meets requirement**: 2015 Utah RH SIP at XX.D.6(c) (including TSD "Staff Review" Table 2 dated May 13, 2015)	**Meets requirement**: 81 FR at 2015, 2021
308(e)(2)(i)(E)	Use "weight of evidence" to determine greater reasonable progress	**Meets requirement**: 2015 Utah RH SIP at XX.D.6(a), (c) (including TSD "Staff Review" dated May 13, 2015)	**Meets requirement**: 81 FR 2016-19 and 2021-24
308(e)(2)(iii)	Emission reduction timing	**Meets requirement**: 2015 Utah RH SIP at XX.D.6(e)	**Meets requirement**: 81 FR 2019, 2025
308(e)(2)(iv)	Surplus reductions	**Meets requirement**: 2015 Utah RH SIP at XX.D.6(c) (including TSD "Staff Review" Table 2 dated May 13, 2015)	**Meets requirement**: 81 FR 2019, 2025

Regulation	Summary	Utah SIP	SIP Proposal
CAA §7491(g)(1), (2); Preamble BART Alternative rule; Appendix Y[7]	Cost Difference	**Meets requirement** 2015 Utah RH SIP at XX.D.6(c) (including TSD "Staff Review" Table 2 dated May 13, 2015)	**Meets requirement:** EPA proposed to ignore this requirement, but should not have.
CAA §7491(g)(1), (2); Appendix Y	Energy and non-air quality impacts	**Meets requirement** 2015 Utah RH SIP at XX.D.6(c) (including TSD "Staff Review" Table 2 dated May 13, 2015)	**Meets requirement:** EPA proposed to ignore this requirement, but should not have.

Notwithstanding EPA's lengthy Proposed Action (which covers 48 pages in the Federal Register), whether or not EPA ultimately must approve the Utah SIP boils down to whether the BART Alternative in the Utah SIP meets the Applicable BART Alternative Requirements. Because it does as EPA properly proposes to conclude and as demonstrated by the Utah SIP itself, EPA must approve the Utah SIP. It is that simple.

C. <u>Inapplicable Regional Haze Requirements</u>

EPA is <u>not</u> correct in its attempt in the Proposed Action to impose additional requirements on its evaluation of the BART Alternative and Utah SIP that are different than that Applicable BART Alternative Requirements.

1. *<u>Reasonableness Standard</u>* –EPA asserts that Utah "has several options for making the greater reasonable progress determination [and it] elected to use two separate approaches."[8] See 81 FR at 2006. EPA further states that it will evaluate both of those approaches in deciding whether to approve the Utah SIP. EPA then makes the blanket assertion that "the State's discretion in this area is subject to the condition that it must be reasonably exercised and that its decisions be supported by adequate documentation of its analysis." ("**Reasonableness Standard**.") See 81 FR at 2006. Although the use of words like "reasonable" and "adequate" have common sense appeal in the abstract, EPA may not apply this standard in a way that allows EPA to discard the state's discretion and instead impose EPA's own will. (See generally

[7] As explained in more detail below, consideration of the cost difference between the SIP Proposal and the FIP Proposal is another underlying aspect of the Applicable BART Alternative Requirements which EPA fails to acknowledge in the SIP Proposal. See 81 FR at 2024 ("…it is not material to our action whether we agree or disagree with Utah's conclusion that the BART Alternative would have lower cost impact….")

[8] As explained below, EPA is simply wrong in concluding that Utah used two separate approaches to demonstrate greater reasonable progress. Therefore, EPA's stated basis for imposing the Reasonableness Standard does not support EPA's effort to do so.

Paragraphs (2) and (3) of PacifiCorp's written comments dated August 26, 2013 as submitted in EPA Docket ID No. EPA-R08-OAR-2012-0026 and identified in that docket as ID. No. EPA-R08-OAR-2012-0026-0149; a portion of these comments is attached hereto as Attachment 2.)

In addition, the present circumstances regarding the SIP Proposal are far different than those circumstances in which courts have upheld EPA's use of a similar Reasonableness Standard in other regional haze settings. For example, in North Dakota v. EPA, 730 F.3d 750, 760 (8th Cir. 2013), the court allowed EPA's use of the Reasonableness Standard under those circumstances where the state's BART determination contained "data flaws that led to an overestimated costs of compliance." Also, Oklahoma v. EPA, 723 F. 3d 1201, 1212 (10th Cir. 2013) reached a similar conclusion based on "methodological flaws."

In the case of the SIP Proposal, however, EPA proposes to approve the BART Alternative based on compliance with the Applicable BART Alternative Requirements[9] and without also concluding that the BART Alternative contains "data flaws" or "methodological flaws." Therefore, the factual bases for allowing EPA to apply a Reasonableness Standard do not exist in regard to the BART Alternative and EPA should not attempt to apply such a standard here – particularly as a basis for rejecting the BART Alternative.[10]

2. *Complexity of Evaluation Standard* - EPA also is wrong in its attempt to count among applicable requirements the unsupported conclusion that the "complexity of our evaluation" somehow necessitates EPA soliciting comments not only on the SIP Proposal, but also on the competing FIP Proposal. See 81 FR 2006.[11] Even taking at

[9] See generally 81 FR 2021 – 2026.

[10] This is not to say that EPA lacks any role in reviewing and approving the Utah SIP. Indeed, the latest court to weigh in on EPA's review authority makes clear that "Congress intended that EPA, not the states alone, ultimately ensure that state determinations as to regional haze comply with the [Clean Air] Act…." Arizona ex rel. Darwin v. EPA, No. 13-70366, slip op. at 19-20 (9th Cir. Feb. 4, 2016). Although PacifiCorp agrees that EPA has a role to play in making sure the Utah SIP complies with the CAA and applicable requirements, it also notes that EPA must do so in a way that does not undermine the role of states like Utah to which "Section 169A [of the CAA] gives…substantial responsibility in determining appropriate BART [and BART Alternative] controls." The court goes on to make clear that "EPA may not disapprove reasonable state determinations that comply with the relevant statutory and regulatory requirements." Id. at 22. Such is the case with the Utah SIP.

[11] EPA attempts to further support this contrived "complexity" requirement by repeatedly stating that such a requirement exists, as if repetition alone somehow can bring an imaginary requirement into existence (i.e., "In light of the variety of metrics Utah used, this is a complicated analysis…;" "The complexity of our evaluation leads us to propose and solicit comments on two conclusions and two courses of action…;" "Given the complexities in evaluating these co-proposals, EPA wants to ensure that our final

face value the assertion that analyzing the Utah SIP is "complicated" (and what regional haze analysis isn't?), that alone does not require EPA to evaluate the Utah SIP differently than any other regional haze SIP, nor does it justify EPA in presenting dueling co-proposals.[12] In other words, EPA has simply conjured up this new "complexity" requirement[13] out of thin air in an attempt to support its offering of the competing FIP Proposal. EPA is acting arbitrarily and without legal authority by seeking comment on the FIP Proposal based on what EPA calls the "complexity of our evaluation" and for this reason EPA should withdraw the FIP Proposal and approve the SIP Proposal as proposed.

III. PacifiCorp's Response to Certain EPA Comments

In this section, PacifiCorp responds to some of the comments made by EPA in evaluating the Utah SIP in light of Applicable BART Alternative Requirements. PacifiCorp offers these comments in an effort to bolster the record upon which EPA should take final action to approve the BART Alternative and the Utah SIP, while simultaneously not approving the FIP Proposal.

A. Applicable BART Alternative Requirements

EPA properly notes that "Utah has opted to establish an alternative measure (or program) for NOx in accordance with 40 CFR 51.308(e)(2)." As described in the table above, the

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decision is based on the best and most currently available data and information, and is taken with the fullest possible consideration of public input.") See 81 FR at 2006.

[12] The Tenth Circuit Court of Appeals, which considered whether EPA's approval of a BART Alternative for SO2 emissions was appropriate, did not conclude that EPA's analysis of the alternative program was, by its nature, more complicated than a BART analysis. See generally WildEarth Guardians v. EPA, 770 F.3d 919 (10th Cir. 2014).

[13] EPA further attempts to justify its rationale for considering the FIP Proposal by asserting, as explained in footnote 3, the need to "ensure that our final decision is based on the best and most currently available data and information, and is taken with the fullest possible consideration of public input." EPA already is charged with ensuring that any final decision is based on the best current data and information available. See Final Rule, Regional Haze Regulations; Revisions to Provisions Governing Alternative Source-Specific BART Determinations, 71 Fed. Reg. 60612, 60622 (Oct. 13, 2006); see also, 5 U.S.C. § 706(2). EPA already is required to make a decision based on the fullest possible consideration of public input. See 5 U.S.C. §553(c). Re-stating these fundamental principles does not allow EPA to bootstrap itself into also considering a competing co-proposal (the FIP Proposal) when the SIP Proposal already meets all Applicable BART Alternative Requirements as EPA itself has proposed to conclude. Arizona ex rel. Darwin v. EPA, No. 13-70366, slip op. at 22 (9th Cir. Feb. 4, 2016) (stating that "EPA may not second-guess reasoned, legally compliant state decisions.") (internal citations and quotations omitted).

Applicable BART Alternative Requirements are straightforward, and EPA properly proposes to conclude that the Utah SIP complies with them. See 81 FR at 2021-27. Although PacifiCorp supports EPA's proposed conclusion,[14] it disagrees with some reasons applied by EPA in reaching that conclusion. PacifiCorp believes that applying proper reasoning will strengthen EPA's conclusion that the BART Alternative under the Utah SIP demonstrates greater reasonable progress.

1. *Greater Emission Reductions Test* – EPA asserts that Utah applied both[15] the "greater emission reductions" test (40 C.F.R. 51.308(e)(3)) and the "weight of evidence" test (40 C.F.R. 51.308(e)(2)) to conclude that the BART Alternative achieves greater reasonable progress. See 81 FR 2021, 2028. Also, EPA proposes to conclude that Utah failed to satisfy the greater emission reductions test. Id. at 2028. Further, EPA asserts that "[w]hile in the aggregate there are fewer SO2 and PM10 emissions for the BART Alternative, the total NOx emissions are greater under the BART Alternative than the BART Benchmark." Id. EPA, however, is simply wrong in its assertion that Utah applied the greater emission reductions test under 51.308(e)(3) in support of the Utah SIP. Utah, in fact, intentionally did not apply the greater emissions reductions test:

   > "Utah has chosen to use a weight-of-evidence approach under 40 CFR 51.308(e)(2)(i)(E), as described in section VII of the staff review. The separate visibility analysis described in section VIII is part of the weight-of-evidence demonstration and is not intended to provide the type of modeling demonstration that would otherwise be required under 40 CFR 51.308(e)(3)." See Utah SIP Staff Review (Chapter 1) at page 31 (May 13, 2015)

   The Utah SIP could not be any clearer on this point.[16] EPA's proposal to disapprove an assumed "greater emissions reduction test" portion of the Utah SIP is tantamount to setting up a straw man for the sole purpose of knocking it down. EPA should not

[14] As noted above, this conclusion is the end of EPA's authority to review the Utah SIP because 42 U.S.C. §7410(k)(3) requires EPA to approve the SIP Proposal given that it meets all Applicable BART Alternative Requirements.

[15] According to the U.S. Court of Appeals for the 10th Circuit, greater reasonable progress can be demonstrated using *either* one of two methods: (i) "greater emission reductions" than under BART (40 C.F.R. §51.308(e)(3)); or (ii) "based on the clear weight of evidence" (40 C.F.R. §51.308(e)(2)(E)). WildEarth Guardians v. EPA, 770 F.3d 919, 935-37 (10th Cir. 2014). As the court observed, the state is free to choose one method or the other. The court characterized the former approach as a "quantitative" and the later as "qualitative," and specifically sanctioned the use of qualitative factors alone under the clear weight of evidence test to demonstrate greater reasonable progress.

[16] In fact, EPA's May 1, 2015 letter to the Utah Division of Air Quality (noted above) regarding the then-proposed Utah SIP acknowledges that Utah is applying only "its weight-of-evidence analysis" and not the greater emission reductions test.

rely on any conclusion or inference[17] created by asserting that Utah failed to meet the greater emission reductions test, and EPA should erase any such reference from its final action.

2. *Greater Reasonable Progress* – The crux of approving a BART Alternative is determining that it produces greater reasonable progress than BART. See 40 CFR 51.308(e)(2)(i)(e). Indeed, upon evaluating certain evidence[18] in regard to the Utah SIP, EPA properly proposes: (i) "to find that the BART Alternative is likely to achieve greater reasonable progress;" and (ii) "to approve Utah's determination that the Utah BART Alternative would achieve greater reasonable progress than BART…." See 81 FR at 2022 and 2025. EPA should take final action consistent with this proposal.[19]

3. *Annual Emissions Comparison of Visibility Impairing Pollutants* – In proposing to conclude that the Utah SIP demonstrates greater reasonable progress, EPA correctly notes that that the "combined emissions of NOx, SO2 and PM10" under the BART Alternative "will be 2,856 tpy lower" than emissions resulting from the BART Benchmark.[20] See 81 FR at 2022. EPA properly proposes to view these aggregate

[17] As explained above, EPA goes to great lengths in attempting to paint the Utah SIP as being more complicated than other regional haze SIPs, thus requiring EPA to also consider the dueling FIP Proposal. Because EPA never had the need to consider the greater emission reductions test under 51.308(e)(3) in its review of the Utah SIP, EPA's presumed complexity is reduced and EPA's purported necessity to consider two co-proposals is further diminished.

[18] EPA described the clear weight-of-evidence standard as follows: "'Weight of evidence'" demonstrations attempt to make use of **all available information and data** which can inform a decision while recognizing the relative strengths and weaknesses of that information in arriving at the soundest decision possible. Factors which can be used in a weight of evidence determination in this context may include, but not be limited to, future projected emissions levels under the program as compared to under BART, future projected visibility conditions under the two scenarios, the geographic distribution of sources likely to reduce or increase emissions under the program as compared to BART sources, monitoring data and emissions inventories, and sensitivity analyses of any models used." (Emphasis added.) See 71 FR 60612, 60622 (Oct. 13, 2006); Compare 81 FR at 2011-12.

[19] Similarly, EPA has approved, or proposed to approve, other BART Alternatives that include "inter-pollutant trading" when SO2 levels were lower. 79 FR 33438, 33440-41 (Washington, June 11, 2014); 79 FR 56322, 56328 (Arizona, Sept. 19, 2014).

[20] As noted above, EPA has described the BART Benchmark as "the best system of continuous emission control technology available and the associated reductions for each source subject-to-BART covered by the alternative program…." See 81 FR at 2011. Specifically, EPA considers the BART Benchmark under its Proposed Action to be "the

emissions reductions "as part of the overall weight-of-evidence analysis," to be a materially positive factor in leading to visibility improvement.[21] Id. In every other context and program under the CAA, lower overall emissions are considered a positive result. 42 U.S.C. §7401(c). EPA agrees this is true in the Utah SIP context as well, first by acknowledging that total SO2 and total PM emissions are reduced significantly on an individual pollutant basis under the BART Alternative. In fact, EPA notes that SO2 emissions will be reduced by 8,005 tpy under the BART Alternative. Also, when EPA steps out of the theoretical world of visibility modeling and into the real world of monitored visibility improvements, EPA agrees that aggregate emission reductions under the BART Alternative will have a greater measureable impact on improving visibility during more parts of the year than additional NOx reductions would achieve under the BART Benchmark.[22] 81 FR at 2022. Thus, under the BART Alternative, any potential adverse impact to visibility caused by a smaller decrease of NOx emissions (compared to the BART Benchmark)

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most stringent NOx BART controls, SCR plus new LNBs and SOFA, at the four BART units." Id. at 2015.

[21] EPA is blatantly wrong, however, in taking the opposite approach on this point in its proposal to approve the FIP Proposal and reject the SIP Proposal. See 81 FR at 2029. There, EPA blindly concludes that "a comparison of emissions of multiple pollutant species of emissions [sic] is generally not informative, particularly when the Agency is addressing whether an approach provides for greater reasonable progress towards improving visibility." This conclusion is demonstrably wrong, however, for the very reasons EPA has proposed to approve the BART Alternative in regard to this particular metric. For example, EPA concludes in support of the BART Alternative that, based on this very same metric, "the BART Alternative is likely to achieve greater reasonable progress," particularly in light of CALPUFF modeling results that shows greater SO2 emissions reductions under the BART Alternative improve visibility far more than additional NOx emissions reductions under the BART Benchmark. Id. at 2022. EPA also asserts in the FIP Proposal that, because each pollutant species reacts differently to humidity, chemistry, geography, etc., EPA should not consider the visibility improvement resulting from the collective emissions reductions. This conclusion also is demonstrably wrong for the reasons EPA states in proposing to approve the SIP Proposal. For example, EPA attempts to use the very reasons why EPA should approve the BART Alternative – the significant visibility improvement associated with the SO2 reductions because of humidity, chemistry, geography, etc.—as bureaucratic rationale to not approve the BART Alternative. Id. at 2022. Also, EPA's FIP Proposal holds up as the deciding factor visibility improvements resulting from fewer NOx emission reductions under the BART Benchmark. At the same time, EPA acknowledges that this cannot actually be the case because it is SO2 emission reductions under the BART Alternative – and not NOx emission reductions under the BART Benchmark – that results in the greater visibility improvements during all parts of the year. Id. at 2022-24.

[22] "However, for reasons described later in subsection vii for our evaluation of Utah's IMPROVE monitoring metric, we propose to concur with Utah's finding that SO2 emissions reductions should provide visibility benefits in all seasons and that sulfate is the largest contributor to visibility impairment at the affected Class I areas. Furthermore, we propose to find that these observations suggest that the BART Alternative is likely to achieve greater reasonable progress." See 81 FR at 2022.

is overcome by the increased visibility benefits of combined overall emission reductions.[23] In that case, EPA properly proposes to conclude that such significant aggregate emission reductions should be considered as an important element entitled to substantial weight in determining greater reasonable progress.

4. *Improvement in the Number of Days With Significant Visibility Impairment* – EPA also properly recognizes that, when analyzing the total number of days for the years modeled, fewer days with significant visibility impacts will occur under the BART Alternative as compared to the BART Benchmark. See 81 FR at 2022. EPA describes this metric as "useful in assessing the frequency and duration of significant visibility impacts from a source or small group of sources." *Id.* In fact, EPA's model shows that the BART Alternative will produce 18 fewer days of impact above the causation threshold of 1.0 dv threshold, and 175 fewer days of impact above the contribution threshold of 0.5 dv.[24] *Id.* EPA thus concludes that such modeled improvements are "an indication that the BART Alternative achieves greater reasonable progress."[25] Id.

   EPA's consideration of this type of information is consistent with 40 CFR 51, appendix Y (the "**BART Guidelines**"), where Section IV.D.5 states that, in determining BART, "comparison thresholds can be used in a number of ways in evaluating visibility improvements…."[26] As explained below, PacifiCorp encourages EPA to apply significant weight to this particular metric, including a conclusion that such modeling results show strong evidence of greater reasonable progress.

   In any case, the use of this metric takes a holistic view of visibility improvement, which is deserving of significant consideration by EPA.[27] By comparison, the 98th

[23] This is so even though the visibility improvements associated with NOx assumed under the BART Benchmark are wildly overstated. See Comments on the Use of CALPUFF Model in the EPA Proposed Rule on the Utah Regional Haze SIP, prepared by Gale F. Hoffnagle, TRC Environmental Consultants, dated March 2016, ("**Hoffnagle Report**") and attached hereto as Attachment 3. If the visibility improvements associated with NOx were stated properly, then the modeled visibility improvements under the BART Alternative would be even greater and provide even more reason for EPA to approve the BART Alternative.

[24] EPA summarizes the number of days of impact differently at 81 FR 2024 where it concludes that there are 48 fewer days of impact of 1.0 dv or more, and 154 fewer days of impact of 0.5 dv or more, under the BART Alternative. Under either set of numbers, of course, the BART Alternative produces greater reasonable progress.

[25] EPA also should consider the average number of days above the noted thresholds as contained in Tables 5 and 6 of the Proposed Action (16 fewer days for 1.0 dv, and 58 fewer days for 0.5 dv under the BART Alternative). This additional evidence supports EPA's proposed conclusion that that BART Alternative demonstrates greater reasonable progress.

[26] See 81 FR at 2022, including footnote 84.

[27] Thus, EPA's criticism of this very metric in support of the FIP Proposal – and in particular the 18 days of fewer impacts over 1.0 dv – misses the mark. See 81 FR 2029.

percentile metric (addressed below) presents more of a rifle-shot metric that focuses on a single day[28] of visibility improvement and inherently is less reliable for evaluating the BART Alternative.

5. *98th Percentile Impact (dv)* – EPA asserts that:

> "The 98th percentile visibility impact is a key metric recommended by the BART Guidelines when selecting BART controls. In addition, this is one of the primary metrics that EPA has relied on in evaluating prior regional haze actions that have included BART alternatives. In the BART Guidelines, EPA described this metric as an appropriate measure in determining the degree of visibility improvement expected from controls. Therefore, we propose to find that it is an appropriate metric for assessing the relative benefits of the Utah BART Alternative here." See 81 FR at 2022.

In other words, the core reasons why EPA proposes to rely on the 98th percentile metric in evaluating the BART Alternative are because: (i) this metric is recommended in the BART Guidelines for determining BART; and (ii) EPA has used it in other regional haze actions that have include BART alternatives. Neither reason, however, requires EPA to consider the results of 98th percentile metric to be of more than marginal worth, especially given the flaws inherent in the use of the CALPUFF model.

As explained in the Hoffnagle Report (and in greater detail below), the 98th Percentile metric measures only the 8th highest impact day, and even then, it greatly overestimates the modeled visibility improvement. For example, when correcting for the margin of error rates inherent in the model, EPA's presumed visibility improvement resulting from the BART Benchmark becomes virtually non-existent. This information makes clear that EPA should take into account the inherent weakness of this metric (due to the margin of error rates and other reasons explained

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There, EPA admits that the 175 days of fewer visibility impacts over 0.5 dv holds up even under its trumped-up criticism (and therefore "the results of the 0.5 dv threshold favor the BART Alternative"). EPA goes on, however, to simply change the metric by which it evaluates the visibility benefit resulting from 18 fewer days over 1.0 dv of impact. (Total days across all Class I areas vs. average days at each Class I area.) In addition, EPA unilaterally ignores, under the FIP Proposal, the precedent it cites in support of the metric it uses to evaluate the SIP Proposal. EPA got it right the first time under the SIP Proposal, should stick with those metrics, and conclude that they support approval of the SIP Proposal.

[28] The Proposed Action recognizes the limitations of the 98th Percentile Impact analysis as compared to other metrics by stating that, "the annual average does provide an indication of the modeled visibility impacts for the entire year while the 98th percentile modeled results speak to a particular day (the 8th highest impacted day)." See 81 FR at 2023 (emphasis added).

in the Hoffnagle Report) in regard to the BART Alternative.[29] In this light, EPA should give little to no weight to this metric in evaluating the BART Alternative. This is particularly true because the BART Guidelines make use of the 98th Percentile Impact metric permissive even in the context of evaluating BART: "[T]he following is an approach that you may use to determine visibility impacts...," which includes comparing "the 98th percent days for the pre- and post-control runs." See BART Guidelines at Section IV.D.5 (emphasis added). As a discretionary tool, the result of this metric alone should not determine the outcome of EPA's decision regarding the BART Alternative.[30]

Also, the BART Guidelines make clear that, even in the context of determining BART, states "are free to determine the weight and significance to be assigned" to this factor. In other words, even the BART Guidelines confirm that Utah could "determine the weight and significance" of the 98th Percentile metric, which is exactly what Utah did. This is another reason why, if EPA considers the 98th Percentile metric at all, it should give it only marginal weight to it in evaluating the BART Alternative.

In addition, EPA's conclusion in applying the 98th Percentile Impact analysis is that, "on the whole… the BART Benchmark is better on average across all years and all Class I areas (0.14 dv difference)." 81 FR at 2030. By any candid measure, however, such a small difference is not only too miniscule to be of any value, but falls well within the margin of error of the complex modeling calculations used to reach this conclusion as explained in the Hoffnagle Report. In fact, EPA has determined in other states that visibility improvements even greater than 0.14 are too small or inconsequential to justify additional pollution controls in the BART context. (See 77 FR 24794 (0.27 dV improvement termed "small" and did not justify additional pollution controls in New York); 77 FR 11879, 11891 (0.043 to 0.16 ΔdV improvements considered "very small additional visibility improvements" that did not justify NOX controls in Mississippi); 77 FR18052, 18066 (agreeing with Colorado's determination that "low visibility improvement (under 0.2 ΔdV)" did not justify SCR for Comanche units)). Tellingly, the "low visibility improvements" that Colorado found at the Comanche units not to justify post-combustion NOX controls -- as agreed to by EPA -- were 0.17 and 0.14 ΔdV. 77 FR at 18066. In evaluating the BART Alternative here, EPA should not rely on this tiny modeled dv improvement to

[29] EPA's explanation (above) is that the weight-of-evidence test includes considering "sensitivity analyses of any models used." This makes clear that EPA should take into account the weaknesses of the CALPUFF model in giving this metric little to no weight.

[30] EPA does not explicitly state that use of the 98th Percentile Impact analysis is determinative of its proposal to approve or reject the BART Alternative even though it concludes this metric "favors the BART Benchmark." See 81 FR at 2022. EPA does, however, place a disproportionately great weight on this metric in the co-proposal to approve the FIP Proposal and reject the SIP Proposal. Id. at 2030.

support the conclusion that "this metric favors the BART Benchmark" (81 FR at 2030) when it really does no such thing for the reasons noted above.

6. *Annual Average Impact (dv)* – EPA properly concluded that it should consider the Annual Average Impact metric because it "provides additional useful information." See 81 FR at 2023. EPA also properly focuses on this metric because it provides "an indication of the modeled visibility impacts for the entire year" as compared to the 98th Percentile Impact analysis which focuses on a single day. Id. In other words it provides a wide-angle view of visibility improvement over a long period of time instead of the compressed telephoto perspective of looking at a single day. This is important when considering the BART Alternative under the weight-of-evidence analysis which allows a state, as explained above, to consider the relative strengths and weaknesses of information and data. Although EPA acknowledges the dv impact resulting from "this metric is small (0.009 dv)," EPA still properly proposes to find – because of the more expansive nature of this metric - that it at least marginally "supports a conclusion that the BART Alternative achieves greater reasonable progress." Id.

   In evaluating the FIP Proposal, however, EPA flips all of this rationale on its head and instead proposes to conclude that this metric "does not support a conclusion that the BART Alternative achieves greater reasonable progress than the BART Benchmark." 81 FR at 3030. To support this opposite conclusion, EPA tries to force this wide-angle view into a more compressed form and essentially argues that the metric provides weak data and information because: (i) "this metric shows less or equal visibility improvement at four of the nine Class I areas;" and (ii) "it does not represent the benefits of the BART Alternative on the maximum impact days." Id. The weight-of-evidence test, however, does not allow for such trickery by EPA. EPA cannot change the focus of the metric under its FIP Proposal. In evaluating this metric at face value (without demanding that it be more or different than it is), EPA should stick with its conclusion that it provides some support under the weight-of-evidence analysis for approving the BART Alternative.

7. *90th Percentile Impact (dv)* – As with the Annual Average Impact metric, EPA properly concluded to consider the 90th Percentile Impact metric which "shows that the BART Alternative is better at seven of the nine Class I areas and is slightly better averaged across three years and across nine Class I areas (0.006 dv difference)." EPA uses this metric even though "the use of the 90th percentile impacts to evaluate alternatives has not been EPA's practice for source-specific BART determinations…." See 81 FR at 2023. Because of the expansive weight-of-evidence test which considers "all available information and data" as described above, EPA is correct to take this metric into account and conclude that it somewhat "supports a conclusion that the BART Alternative achieves greater reasonable progress." Id. Use of the 90th Percentile metric actually provides a more useful look at modeled visibility improvement because it evaluates the 10% worst impacted day as opposed to the 2% worst impacted day under the 98th Percentile metric. Because the BART rule partially

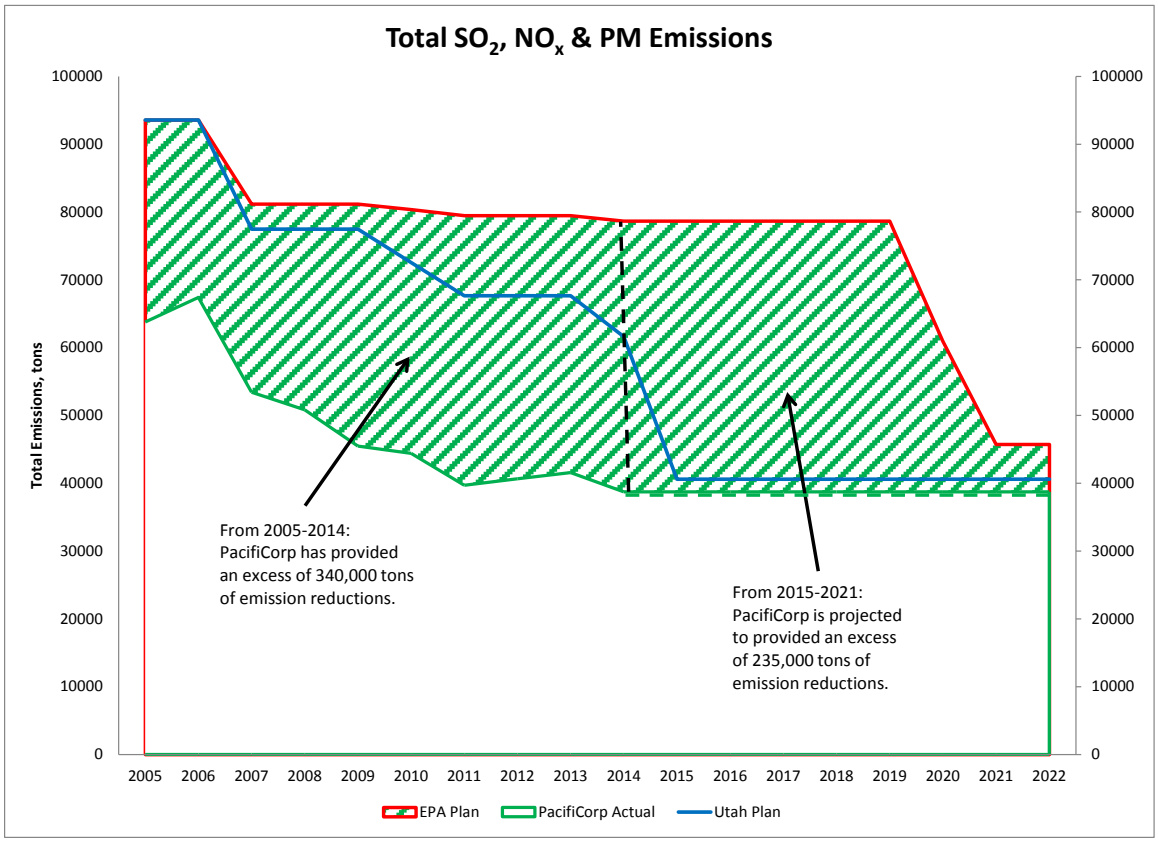
targets improving visibility during the 20% worst days, of all the metrics used by Utah and EPA to evaluate the BART Alternative the 90th Percentile metric comes closest to evaluating those targeted days. That alone suggests that this metric should be afforded some weight in evaluating the BART Alternative as EPA has proposed. EPA takes the opposite approach, however, when it comes to the FIP Proposal. There, EPA baldly concludes only that the use of this metric is "questionable" support for the BART Alternative. Id. at 2030. Simply slapping the label "questionable" on this metric without further support does not make it so, nor does it make this metric unavailable to support EPA's analysis under the SIP proposal that it "supports a conclusion that the BART Alternative achieves greater reasonable progress." Id. at 2023. This is particularly true in light of the Hoffnagle Report's comments regarding the 90th Percentile metric.

8. *Timing for the Emissions Reductions* – In considering the Timing of Emissions Reductions metric, EPA notes simply that "the reductions from the BART Alternative will occur before the BART Benchmark." See 81 FR at 2023. Although this is a true statement on its face, EPA does an extreme disservice to Utah, PacifiCorp, its customers and the general public by including such an underwhelming description of the meaningful and large visibility benefits associated with the timing of emissions reductions under the BART Alternative[31] as compared to the BART Benchmark. In approving the BART Alternative, PacifiCorp strongly encourages EPA to more completely describe both the tremendous scope, and the overwhelmingly positive visibility impact, of the timing of emission reductions under the BART Alternative as compared to the BART Benchmark.

   The table below shows the timing of controls installed under the BART Alternative, along with: (i) the total tons of emissions reductions achieved since the date of the installation of the controls; and (ii) the projected emissions reductions to be achieved until the time when the BART Benchmark is expected to be implemented.[32]

[31] In at least three other portions of the Proposed Action, EPA at least acknowledges that the "reductions under the Utah BART Alternative are required under the State SIP by August 2015, as noted in Table 5, providing an **early and on-going visibility benefit as compared to BART**." (emphasis added) See 81 FR at 2018, 2024, and 2030. In addition, EPA states in the Proposed Action that: "Also notable is that combustion control upgrades at the Hunter and Huntington facilities have been achieving significant NOx reductions **since the time of their installation between 2006 and 2014**." (emphasis added) Id. at 2030. At the critical point of describing in the Proposed Action the timing of reductions as evidence to consider under the Weight of Evidence analysis, however, EPA could not even be bothered to do more than nominally and incompletely describe that evidence, leaving out the importance, scope and impact of the timing of such significant emissions reductions. This, in turn, led to EPA incompletely evaluating the weight of this evidence when considering the SIP Proposal (even though EPA actually reaches the proper conclusion in proposing to approve the BART Alternative).

[32] EPA projects that the BART Benchmark "likely would be fully implemented sometime between 2019 and 2021." See 81 FR at 2030.



As can be seen, the BART Alternative already has produced a total of 340,000 tons of combined emission reductions beginning in 2007 and continuing through 2014. And these emissions reductions have occurred at a time long before the BART Benchmark ever would be implemented. In addition, the BART Alternative is expected to continue to produce significant emission reductions between now and the time of the BART Benchmark (and beyond). EPA should specifically note the significant visibility benefits associated with the timing of these emissions reductions and assign them great weight under the Weight of Evidence test.[33] What EPA should not do, however, is brush over the Emission Reduction Timing metric by failing to adequately describe or consider the significant timing benefits as EPA appears to have done in its tepid conclusions regarding the weight of the Emission Reduction Timing metric in evaluating the BART Benchmark.

Even in evaluating its FIP Proposal, EPA cannot escape acknowledging the benefits of the timing of emission reductions achieved under the BART Alternative as

[33] The U.S. Circuit Court of Appeals for the 10th Circuit explicitly acknowledged that the consideration by EPA of emission reductions occurring at an early point in time is a proper part of a clear weight of evidence approach to determining greater reasonable progress. WildEarth Guardians v. E.P.A., 770 F.3d 919, 938 (10th Cir. 2014).

compared to the BART Benchmark. Indeed, EPA does not, and cannot, offer any criticism to the contrary and instead concludes that: "we recognize that the reductions from the BART Alternative would occur before the BART Alternative." See 81 FR at 2030. Therefore, even though EPA has employed every tactic it can think of criticize other metrics used to evaluate the BART Alternative under its FIP Proposal, EPA makes no such attempt when it comes to the timing metric. This failure is additional evidence that the timing metric should carry great weight in EPA's weight-of-evidence analysis in support of the BART Alternative and this metric in no way supports the FIP Proposal.

9. *IMPROVE Monitoring Data* – EPA properly reaches the following conclusions: (i) "anthropogenic visibility impairment on the Colorado Plateau is dominated by sulfates;" (ii) "sulfate is the largest contributor to visibility impairment at the affected Class I areas;" (iii) "SO2 reductions should provide visibility benefits in all seasons;" and (iv) "visibility benefits associated with NOx reductions are much more likely to occur [only] in the winter months." See 81 FR at 2023-2024. These conclusions properly support the BART Alternative because it requires more significant reductions of SO2 emissions as the primary driver of year round visibility improvements. This is true even though the BART Alternative supports fewer reductions of NOx emissions (compared to the BART Benchmark) because further NOx reductions do not contribute as significantly to visibility improvement, and even when they do, it is only during very limited times of the year with lower visitation rates in affected Class I areas.

   EPA's proposal to disagree with Utah's findings in regard to lower park visitation during the winter season, however, lacks merit. As EPA acknowledges, the BART Guidelines allow for states like Utah to "determine if the time of year is important (e.g., high [visibility] impacts are occurring during tourist season…. States may develop other methods as well." See 81 FR at 2024, footnote 109. EPA's decision to not consider this fact in regard to NOx emissions under the BART Alternative is directly contrary to the cited BART Guidelines. Utah did not assert, as EPA seems to think, that slow-season, winter month visitors are entitled to less visibility protection than visitors during high-season, summer months. But consistent with the BART Guidelines, Utah properly considered this fact among others under the weight-of-evidence analysis. EPA should do the same rather than reject this approach out of hand.

   As with the timing metric discussed above, EPA does not attempt to criticize this metric in regard to its FIP Proposal (except for the winter visitor information described above). See 81 FR at 2031. This alone is additional evidence that the IMPROVE Monitoring Data metric should carry great weight in EPA's weight-of-evidence analysis in support of the BART Alternative and that this metric in no way supports the BART Benchmark.

10. *Energy and Non-Air Quality Benefits* – EPA concludes that the Energy and Non-Air Quality Benefits identified by Utah "do not have a direct bearing on whether the BART Alternative achieves greater reasonable progress" and therefore are not material to EPA's action on the SIP Proposal. See 81 FR at 2024. EPA, however, is not correct in this conclusion. As explained above regarding EPA's own description of the evidence to be considered in the Weight of Evidence evaluation: "'Weight of evidence' demonstrations attempt to make use of **all available information and data** which can inform a decision while recognizing the relative strengths and weaknesses of that information in arriving at the soundest decision possible." (emphasis added) "All available information and data" includes Energy and Non-Air Quality Benefits because they help to inform greater reasonable progress decisions by causing decision-makers to consider concurrent impacts of a particular action. This is especially true given EPA's repeated reliance on the BART Guidelines to evaluate the BART Alternative (specifically the 98th. Percentile metric), and an evaluation of Energy and Non-Air Quality Benefits are an explicit part of those BART Guidelines. See BART Guidelines at Section IV.D.4.i. Additionally, Congress considered this factor as sufficiently important to specifically include it as part of the five-factor BART analysis requirements. 42 U.S.C. §7491(g)(2). Likewise, this factor should be part of EPA's evaluation of the BART Alternative and EPA should consider the impacts identified by Utah as an additional reason to support approval of the SIP Proposal.

    As with the timing and IMPROVE metrics discussed above, EPA does not attempt to criticize this metric in regard to its FIP Proposal. See 81 FR at 2031. This alone is additional evidence that the Energy and Non-Air Quality Benefit metric should carry great weight in EPA's weight-of-evidence analysis in support of the BART Alternative and that this metric in no way supports the BART Benchmark.

11. *Cost* – EPA's decision that "it is not material to our action whether we agree or disagree with Utah's conclusion that the BART Alternative would have a lower cost impact to PacifiCorp than the BART Benchmark" borders on regulatory absurdity.[34] See 81 FR at 2024. As EPA itself acknowledges, the cost of the BART Benchmark is at $400 million more than the cost of the BART Alternative (and PacifiCorp contends the cost is in excess of $700 million more). If the cost difference between EPA's competing co-proposals is not material and worthy of EPA's consideration in taking final action, then what cost information possibly could be?

    EPA's proposal not to consider cost in evaluating the BART Alternative, however, fails for several reasons. First, EPA itself introduced cost as a foundational

[34] This is particularly true because, after announcing that the significantly lower cost of the BART Alternative is not material to its final action, EPA ultimately states that "we do agree" with Utah that the BART Alternative will cost more than $700 million less than the BART Benchmark. See 81 FR at 2024. Such inconsistent reasoning does not support EPA's refusal to consider the cost difference in its BART Alternative analysis.

component of any BART Alternative analysis. In EPA's final Revisions to Provisions Governing Alternative to Source-Specific BART Determinations at 71 FR 60612 (October 13, 2006), EPA lays out the foundation for any state to consider a BART Alternative:

> "The EPA continues to support State efforts to develop trading programs and other alternative strategies to fulfill the goals of the CAA. We believe such strategies have the potential to achieve greater progress towards the national visibility goals than more traditional approaches to regulation, **and to do so in the most cost-effective manner practicable**." 71 FR at 60614. (Emphasis added.)

In other words, in promulgating the BART Alternative rules, EPA recognized that the basis for considering a BART Alternative is twofold: (i) to achieve greater progress towards visibility goals; and (ii) to do so "**in the most cost-effective manner**." EPA cannot pass a rule based on the foundational premise of cost-effectiveness, and then apply that rule with active disregard of the very cost-effectiveness foundation upon which the rule is based.[35] In fact, considering the cost difference of the BART Alternative is consistent with the judicial philosophy which underpinned the U.S. Supreme Court's recent decision in Michigan v. EPA, 135 S.Ct. 2699 (2015). There, the court considered whether it was reasonable for EPA to refuse to consider cost in regard to regulating hazardous air pollutant from power plants. The court noted that:

> "Agencies have long treated cost as a centrally relevant factor when deciding whether to regulate. Consideration of cost reflects the understanding that reasonable regulation ordinarily requires paying attention to the advantages and the disadvantages of agency decisions. It also reflects the reality that 'too much wasteful expenditure devoted to one problem may well mean considerably fewer resources available to deal effectively with other (perhaps more serious) problems.'" Id. at 2707.

Even the dissent in the Michigan v. EPA case agrees on this point: "I agree with the majority—let there be no doubt about this—that EPA's power plant regulation would be unreasonable if '[t]he Agency gave cost no thought *at all*.'" Id. at 2714. As a result, all nine justices of the U.S. Supreme Court sent a clear signal that EPA must consider cost in making agency decisions to achieve emission reduction benefits

[35] EPA acknowledged this principle in arguing to the court in favor of considering "the full structure and function" of the 309 program, which in essence is a BART Alternative: "Petitioners' contention that EPA impermissibly approved the backstop trading program ignores the full structure and function of the 309 program and improperly seeks to narrow the scope of EPA's discretion and this Court's review." See EPA's Primary Brief at page 15 (September 13, 2013), a portion of which is attached as Attachment 4. Likewise, EPA should consider the cost impact of the BART Alternative (including the cost difference as compared to the BART Benchmark) in order to consider "the full structure and function" of the Applicable BART Alternative Rules as described in the preamble to those rules.

(including visibility improvement). Likewise, EPA should consider the cost difference between the BART Alternative and the BART Benchmark as part of the weight-of-evidence analysis instead of actively disregarding that cost difference as EPA has proposed to do.

EPA already has before it as part of this rulemaking docket the very cost saving benefits information it should consider in approving the BART Alternative. These costs savings are material and significant by any stretch of the imagination. EPA's refusal to formally consider the cost information is akin to the position it took in Michigan v. EPA where the court clearly and forcefully ruled that EPA could not "ignore cost." EPA should give up its attempt to do that very thing here.

Second, the CAA requirements and applicable regional haze rules have as one of their foundational components the consideration of cost. See CAA at §7491(g)(1) and (2). Also, see 40 CFR 51.308(d)(1) which states that a core requirement of a regional haze SIP is the inclusion of reasonable progress goals under which "(i)… the State must: (A) consider the costs of compliance"). It is irrational to require the consideration of cost in setting BART and reasonable progress goals, but then assert it is not even a remote consideration when evaluating a BART Alternative. Cost consideration is so fundamental to the fabric of the regional haze statutes and rules that EPA should have little trouble concluding that it must consider those costs in evaluating the BART Alternative (particularly as compared to the FIP Proposal).

Third, EPA's own interpretation of the Weight of Evidence standard is expansive. It includes "all available information and data."[36] All means ***all***. EPA should not now add restrictions to its expansive interpretation in order to prejudicially exclude consideration of material cost impacts and cost differences. In fact, EPA's brief in the SO2 Backstop Trading case explains that the preamble to the applicable regional haze rule allows "all available information and data" to be considered as part of the "weight of evidence" analysis. EPA SO2 Backstop Trading brief at 36, 38, citing to 71 FR at 60621, 60631. Also in its brief, EPA specifically mentioned "lower compliance costs" as "'policy considerations' which EPA may properly assess under the 'clear weight of the evidence' standard when comparing BART to a BART-alternative." EPA SO2 Backstop Trading brief at 42.

Fourth, EPA is wrong to exclude consideration of costs to the extent EPA claims the BART Alternative requirements do not require cost consideration. The Proposed Action offers "two co-proposals" from which "EPA intends to finalize only one proposal." See 81 FR at 2006. The very nature of offering two co-proposals from

[36] In evaluating the Weight of Evidence standard, the U.S. Court of Appeals for the 10th Circuit agreed and stated that EPA itself concluded that the examples EPA listed in the BART Alternative rule described above are "not exhaustive and that the determination should be based on 'all available information and data which can information a decision….'" WildEarth Guardians v. E.P.A., 770 F.3d 919, 935 (10th Cir. 2014).

which to select one is to compare and contrast between them.[37] EPA clearly considers cost to be important in proposing the FIP Proposal.[38] The nature of the Proposed Action as "two co-proposals" requires EPA to consider cost in regard to the SIP Alternative as well, particularly for the purpose of comparing the co-proposals against each other. Also, because EPA relies on non-cost portions of the BART Guidelines in evaluating a BART Alternative, then it also should rely on the BART Guidelines as justification for considering the cost savings of the BART Alternative.

Finally, Utah considered the cost impact of the BART Alternative to be important enough to respond to comments about cost as follows as part of the Utah SIP rulemaking process:

> "PacifiCorp noted in their comments on the proposed SIP revision that the Alternative Measure not only produces greater reasonable progress, including lower emissions and improved visibility, but it does so at a significant capital cost savings to PacifiCorp and its customers as compared to the most stringent NOX technology and limits. While DAQ has not officially determined the cost of installing SCR on the four units, it is clear that it would be a significant cost. On the other hand, the Carbon Plant has already been closed due to the high cost of complying with the MATS rule. The costs to Utah rate payers (and those in other states served by PacifiCorp) to replace the power generated by the Carbon Plant have already occurred; there will be no additional cost to achieve the co-benefit of visibility improvement. ***In other words, the Alternative Measure achieves better visibility improvements than would be achieved by requiring SCR as BART at the four EGUs, and at a significantly lower cost. This presents a classic "win/win" scenario – the Alternative Measure results in greater reasonable progress and that greater reasonable progress is achieved at a much lower price compared to SCR.*** Cost is one of the factors listed in section 169A(g)(2) that should be considered when determining BART." (Emphasis added.) Utah SIP; Staff Review; May 13, 2016 p. 27.

EPA likewise should consider the cost impact and differences in at least a similar manner when evaluating the BART Alternative.

As with the timing, IMPROVE and Energy/Non-Air Quality metrics discussed above, EPA does not attempt to criticize this cost metric in regard to its FIP Proposal. See 81

[37] As explained above, PacifiCorp maintains that EPA is bound to approve the SIP Alternative and is prohibited from even considering the FIP Alternative. Because EPA proposes to consider both, however, PacifiCorp's comments regarding EPA comparing and contrasting the SIP Alternative with the FIP Alternative are applicable.

[38] See 81 FR at 2024: "We do agree" with "Utah's conclusion that the BART Alternative would have a lower cost impact to PacifiCorp than the BART Benchmark…." Also, see Proposed Action at Section VI.D.1.a (Costs of Compliance).

FR at 2031. This alone is additional evidence that the cost metric should carry great weight in EPA's weight-of-evidence analysis in support of the BART Alternative and that this metric in no way supports the BART Benchmark.

B. Evaluation of Weight of Evidence

As explained above, the weight-of-evidence analysis is not the exclusive province of EPA. Rather, in considering whether to approve the SIP Proposal, EPA should give great weight and deference to what evidence Utah selected, how Utah elected to weigh that evidence in evaluating the BART Alternative, and to Utah's conclusions. In other words, it is not EPA's role to apply this test *de novo* as EPA attempts to do here. Because EPA already has properly proposed to find that Utah correctly followed the Applicable BART Alternative Requirements, properly weighed the evidence and available metrics and reached a logical and rationale conclusion, EPA's role should be limited to explaining the foregoing and approving the Utah SIP. This is particularly true given EPA's statement that "it is preferable that the regional haze program be implemented through state plans." See 81 FR at 2006.

PacifiCorp agrees with EPA that the following evidence should carry the most weight: (i) the BART Alternative produces 8,005 fewer tpy of SO2 emissions and 2,856 fewer tpy of combined emissions than the BART Benchmark (see 81 FR at 2024); (ii) the BART Alternative produces 48 fewer days of impact above 1.0 dv, and 145 days of impact above 0.05 dv (*Id.*)[39]; (iii) the IMPROVE monitoring networks shows that a reduction in SO2 emissions (in this case 8,005 tpy) "provides visibility benefits throughout the year" as compared to NOx emission reductions which don't, that "sulfate is the largest contributor to visibility impairment at affected Class I areas," and that the BART Alternative provides for the greatest SO2 reductions (in this case 8,005 tpy more than the BART Benchmark)(*Id.*); and (iv) the BART Alternative produces a far earlier start to emission reductions through earlier installation of emission controls (compared to the BART Benchmark), beginning in 2007 and continuing on through August 2015. (*Id.*) In short, as compared to the BART Benchmark, the above evidence alone (which EPA agrees should carry significant weight) demonstrates that the BART Alternative – as compared to the BART Benchmark -- produces greater reasonable progress in the form or greater SO2 and overall emission reductions, more overall days of improved visibility, better visibility benefits throughout the year, and a significantly earlier start to emission reductions. EPA correctly proposes to conclude that the weight of this evidence produces greater reasonable progress and requires approval of the BART Alternative.

In addition, for the reasons explained above and summarized below, EPA should apply additional weight (or in the case of cost, non-air quality environmental and energy impacts,

[39] Elsewhere in the Proposed Action EPA uses 18 fewer days above the 1.0 dv threshold and 175 fewer days above the 0.5 dv threshold. See 81 FR at 2022, 2029. It is not clear why EPA uses different data here, but the fact is that all of the cited data supports both giving great weight to this metric and EPA's overall conclusion to approve the BART Alternative.

any weight) to the following evidence (or metrics). By doing so, EPA will conclude even more forcefully that it should approve the Utah SIP.

1. *TPY* – As explained above and following Utah's lead in the Utah SIP, EPA has assumed that the SIP Proposal produces a greater reduction in aggregate emission reductions of 2,856 tpy compared to the BART Benchmark. This information, however, presumes that the emission units covered under the BART Alternative have emitted at the maximum amount allowable under applicable permits every minute of every day for 365 days each year. In reality, of course, the units do not function in this manner. Therefore, EPA should also take into account the actual emissions from the affected units in considering the aggregate tpy reductions, at least in considering emissions from 2007 until the present. This information is available above in the chart at page 17. By acknowledging that the SIP Proposal – based on actual emissions data – produced even greater emission reductions than EPA (or Utah) had supposed, this gives EPA even more reason to approve the BART Alternative based on this metric.

2. *Emission Reductions Timing* –Information available above in the chart at page 17 also demonstrates, coupled with accurate emission tonnage reduction amounts, that the BART Alternative provides even greater benefits earlier that EPA has supposed. Having this information in this manner allows EPA to better consider the magnitude of these benefits under the BART Alternative. This, in turn, requires EPA to afford even greater weight to this metric in support of the BART Alternative.

3. *Costs and Energy/Non-Air Quality Impacts* – EPA should consider, as material evidence with significant weight, the cost savings available by approving the BART Alternative as compared to the BART Benchmark. Indeed, EPA will be arbitrary and capricious in its decision-making if it fails to consider this cost difference. This is particularly true if EPA's failure to consider the cost savings under the BART Alternative leads EPA to disapprove the SIP Proposal and instead approve the FIP proposal. This also is true for the energy/non-air quality impacts which EPA should have taken into account.

IV. EPA'S FIP PROPOSAL IS NOT LEGALLY SUSTAINABLE

Not only did EPA improperly reject the Utah SIP Proposal for the reasons described above, it also failed to correctly analyze the five statutory BART factors under its FIP Proposal when it created its NOx BART determinations for the Utah BART Units (Hunter Units 1 and 2, and Huntington Units 1 and 2). In determining BART, EPA recognizes its duty to apply the five statutory BART factors. "In determining BART, the state, or EPA if promulgating a FIP, must consider the five statutory factors in section 169A(g)(2) of the CAA: (1) The costs of compliance; (2) the energy and non-air quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology." See 81 FR at 2032.

EPA, however, failed to properly consider and analyze four of the five BART factors in its FIP Proposal: (i) existing NOx controls; (ii) costs of compliance; (iii) non-air quality environmental and energy impacts; and (iv) reasonably anticipated visibility improvement. For these reasons, EPA should not finalize the FIP Proposal and instead should approve the SIP Proposal.

A. **Existing Controls**[40]

EPA incorrectly claims that it properly considered the existing combustion controls (LNB and SOFA) at Hunter Unit 1 as required by the BART statute and BART Guidelines. See 81 F R at 2034. Rather, as EPA begrudgingly admits, it evaluated "control technologies and baseline emissions" from what it mistakenly claims is the "correct starting point, that is, prior to the installation of the combustion controls pursuant to state-law NOx limitations." Id. at 2036.[41] In other words, while EPA may have noted the presence of the existing controls when identifying the types of potential BART NOx controls, **EPA did not take into account the impact of the existing controls** when actually conducting the statutorily-required BART cost and visibility analyses for Hunter Unit 1, including establishing the baseline emissions to be used in the cost and visibility analyses. **EPA made this same mistake for all of the Utah BART Units.** 81 FR at 2038-40, tbls. 19-24, (Hunter Unit 2); 81 FR at 2042-44 tbls. 25-30 (Huntington Unit 1); 81 FR at 2046-48, tbls. 32-36 (Huntington 2).

EPA's refusal to properly account for "existing controls" violates the CAA and BART Guidelines, and skews EPA's BART analysis. As EPA also is well aware, the Eighth Circuit Court of Appeals found that EPA's similar actions in North Dakota (ignoring existing controls when conducting a BART "cost" analysis) violated the CAA. Finally, EPA took a contrary position for one of PacifiCorp's units in Arizona (Cholla Unit 4, which EPA uses as a comparable benchmark here), making EPA's actions here overtly arbitrary and capricious.

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[40] While PacifiCorp uses Hunter Unit 1's BART analysis as an example here, EPA made the same "existing controls" mistake for all four Utah BART Units. In fact, unless otherwise stated, all of the arguments made herein regarding Utah's FIP Proposal apply with equal force to all of the Utah BART Units.

[41] EPA also emphasizes that it "did not approve" the existing NOx pollution controls. However, the courts, see North Dakota, have held this issue is irrelevant. Moreover, here, where EPA did not act on Utah's regional haze SIP for years, it is disingenuous for EPA to claim it did not approve the controls when EPA withheld its approval/disapproval for years beyond the statutory time frame. In 2008, Utah submitted to EPA a RH SIP containing Utah's BART analyses for PacifiCorp's four BART-eligible units located in Utah, identifying the currently-installed "existing controls" as BART. EPA took no formal action with regard to this 2008 RH SIP, or on a minor 2011 revision (which did not materially alter or modify the 2008 BART determinations), until EPA proposed partial disapproval of the 2011 RH SIP revision on May 16, 2012. By then, Utah's RH SIP was legally binding and PacifiCorp was legally required to install the controls.

1. *The CAA and BART Guidelines Require EPA to consider "existing controls."* -- The language of the regional haze statute is unambiguous; a State/or EPA determining BART must take account of "any existing pollution control technology in use at the source[.]" 42 U.S.C. § 7491(g)(2). The statute is clear. It does not allow EPA to consider "existing controls" for some limited purposes, but ignore them for other important analyses. For example, when conducting a five-factor BART determination, the State/or EPA must determine the "realistic" baseline emissions so that accurate BART cost and visibility analyses can be performed. The BART Guidelines state "[t]he baseline emissions should represent a *realistic* depiction of *anticipated* annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period." 40 C.F.R. pt. 51, app. Y § IV.D.4.d. (emphasis added).

   Here, despite claiming it considered "existing controls," EPA refused to account for the "existing controls" when setting the baseline emissions, a fundamental part of a BART analysis. Instead, EPA used a baseline emission rate founded on 2001-2003 data which did not account for the "existing controls." Moreover, EPA's use of 2001-2003 emissions data to establish the baseline emissions for the Utah BART Units is neither "realistic" nor provides the "anticipated" emissions as required by the BART Guidelines. Using outdated emissions information is not "realistic;" it does not reflect reality at all. For example, the 2001-2003 NOx emissions rate for Hunter 1 was 0.40 lb/MMBtu. 81 FR at 2004, 2034, tbl. 13. After the installation of pollution control equipment in 2014, the actual NOx emissions rate changed to 0.21 lb/MMBtu, a 48.4% decrease. *Id.* at 2034. Therefore, the old 2001-2003 emissions data is no longer "realistic," and represents approximately half of the actual, realistic emissions rate. Moreover, EPA cannot use outdated emissions data to "anticipate" annual emissions from the Utah BART Units because the NOx emissions rates, in fact, have materially changed. This mistake skews EPA's BART decision-making.

2. *The Eighth Circuit rejected EPA's "existing control" interpretation* -- Not only does EPA's "existing controls" approach in the FIP Proposal violate the BART Guidelines, but courts have rejected EPA's approach as well.In North Dakota, a power company had installed pollution control equipment two years before EPA conducted its BART determination. North Dakota v. EPA, 730 F.3d 750, 760 (8th Cir. 2013). The power company argued EPA should consider the existing controls when calculating cost effectiveness, among other things. EPA refused, unsuccessfully arguing that it "was not required to reconsider cost estimates based on voluntarily installed controls installed after the baseline period." Id. at 762. The Eighth Circuit rejected EPA's actions, and its excuses. The North Dakota court held that "EPA's refusal to consider the existing pollution control technology in use at the Coal Creek Station because it had been voluntarily installed was arbitrary and capricious." Id. at 764. The court further held EPA's failure to properly consider the "existing pollution control technology" was contrary to the plain language of the CAA and rejected part of EPA's FIP on this basis. Id. at 762-64.

Here, EPA repeated the same mistake for the Utah BART Units in the FIP Proposal. EPA's NOx BART determinations failed to properly account for the low NOx burners and over-fire air systems ("LNB/OFA") that already had been installed when EPA conducted its BART cost and visibility improvement analyses. Also, EPA refused to consider the existing LNB/OFA for the same reason the court rejected in North Dakota*:* because EPA did not approve the LNB/OFA installation as BART. See, e.g., 81 FR at 2036.[42] EPA's actions in the FIP Proposal are just as illegal as its actions in North Dakota. EPA must redo its NOx BART determinations in the FIP Proposal to account for the "existing controls" in the baseline emissions, BART cost analyses, and BART visibility improvement analyses for the Utah BART Units.

EPA's "existing controls" mistake has significant consequences and materially skews EPA's NOx BART analyses at the Utah BART Units. For example, using outdated baseline emissions data that did not recognize existing controls, EPA calculated "cost-effectiveness" for NOx BART at Hunter Unit 1 assuming that new LNB/OFA had not been installed. See e.g., 81 FR at 2004, 2,034 tbl. 13, 2036. EPA's failure to consider Hunter Unit 1's existing NOx controls caused EPA to overestimate the cost effectiveness of SCR by crediting SCR with the future removal of NOx emissions that, in fact, are already being removed by the existing LNB/OFA. This mistake was caused in large part by EPA's refusal to consider "existing controls" as part of its baseline emission analysis. "Baseline emissions" are an elemental part of a BART cost-effectiveness calculation. 40 C.F.R. Part 51, App. Y, § IV.D.4.d.

EPA also artificially inflated the calculated visibility improvement from SCR by combining the modeled visibility improvement for SCR (which has not yet been installed) with the modeled visibility improvement of LNB/OFA (which EPA knows has already been installed). See e.g. 81 FR at 2,004, 2035-36. Once the CALPUFF modeled visibility improvements from LNB/OFA are removed from that attributed to SCR (1.55 dv at the most impacted Class I area according to EPA's flawed modeling data), the calculated visibility improvements from SCR shrink to 0.70 -- less than the perceptible level of 1.0 dv. Id. at 2035, tbl 15. Many of EPA's other calculated visibility improvements, once the gains from existing LNB/OFA are removed, shrink to numbers that fall within the margin of error for the CALPUFF model, and that cannot be used to justify EPA's FIP Proposal. Nat'l Parks Conservation Ass'n v. E.P.A., 788 F.3d 1134, 1147 (9th Cir. 2015).

In essence, as a result of EPA ignoring the "existing controls" at the Utah BART Units, EPA's NOx BART analyses ask the wrong question. Instead of asking, "what cost and visibility improvements are associated with the installation of LNB/OFA and SCR, even though LNB/OFA are already installed?" EPA should have asked,"what cost and visibility improvements are associated with the installation solely of SCR?"

[42] Moreover, EPA's decision to ignore the "existing controls" is counter-intuitive. As explained above, the "existing controls" have resulted in emissions reductions and related modeled visibility improvements years before EPA's FIP Proposal.

3. *EPA considered "existing controls" at Cholla Unit 4* -- EPA's refusal to recognize existing NOx controls at the Utah BART Units is contrary to not only the BART statute, BART Guidelines, and existing case law, but is also contrary to EPA's past practice at one of PacifiCorp's other units in Arizona (Cholla Unit 4). In the Arizona regional haze rulemaking, EPA said:

> "The presence of existing pollution control technology is reflected in the BART analysis in two ways: First, in the consideration of available control technologies . . . , and *second, in the development of baseline emission rates for use in cost calculations and visibility modeling*. . . . AEPCO, APS, and SRP used baseline time periods that varied from 2001 to 2007. *The respective baseline emissions and existing pollution control technology used in the BART analyses reflect the levels of control in place at the time.* EPA considers ADEQ's approach to be reasonable and generally consistent with the [Regional Haze Rule] and the BART Guidelines." Arizona Proposed RH Rule, See 77 FR at 42834, 42841 (emphasis added).

Moreover, EPA found that adjusting baseline emissions to account for existing controls was necessary to get a "realistic estimate of current visibility impacts and the effect of BART controls." See 77 FR at 42854. EPA reiterated this position in the Arizona Final RH Rule. See 77 FR at 72512, 72526 ("This provision is consistent with the statutory requirement that each BART determination take into consideration 'any existing pollution control technology at the source' . . . in order to 'represent a realistic depiction of anticipated annual emissions for the source' the baseline can account for controls already installed on the source.").

In Arizona, EPA recognized that since it had disapproved Arizona's BART determinations for NOx, EPA was "obligated to conduct [its] own five-factor BART analyses for NOx" and included "existing" NOx controls in the EPA's BART baseline emissions analysis, including for Cholla. *Id.* Here, contrary to its clear position in Arizona and Colorado (and for the Cholla and Hayden power plants, which EPA cites in the FIP Proposal as BART comparisons for the Utah BART Units),[43] EPA ignored existing controls in the development of baseline emission

[43] In its FIP Proposal, EPA compared the cost and visibility analyses from the Utah BART Units to the analyses from the Cholla power plant in Arizona. See e.g., 81 at 2037. PacifiCorp owns Unit 4 at the Cholla power plant. EPA considered existing controls when setting the baseline emissions data for Cholla Unit 4, but will not consider existing controls when setting the baseline emissions data for the Utah BART Units, which PacifiCorp also owns and operates. The "awkwardness" and inconsistency of this approach can be seen in EPA's own comparison language. For example, for Hunter Unit 1, EPA states, "as with Hayden, the *average* cost effectiveness of SCR at Cholla should be compared with the *incremental* cost-effectiveness of SCR . . . at Hunter Unit 1." Id. (emphasis added). Why does EPA require *average* cost effectiveness numbers at Hayden and Cholla to be compared with *incremental* cost effectiveness numbers at Hunter and Huntington? The reason: EPA is arbitrarily applying a different "baseline emissions"

rates. Due to EPA's inconsistencies in applying the baseline emissions methods, EPA's actions are arbitrary and capricious.

4. *EPA Has Considered Existing Controls in Other Settings in Utah* -- Not only are EPA's actions inconsistent with its BART analyses in Colorado and Arizona, but EPA's FIP Proposal is inconsistent with other EPA actions in Utah. Paragraph 11 of DG&T's settlement agreement with EPA Region 8 provides that "in conducting any reasonable progress analysis under the regional haze rule, EPA Region 8 acknowledges that in calculating Deseret's baseline emissions EPA Region 8 intends to reflect any emission reductions that result from a final LNB/OFA Minor NSR Permit and installation of LNB/OFA." Considering existing LNB/OFA at one power plant in Utah for baseline emissions purposes (particularly one that EPA has allowed to escape any previous regional haze analyses), but not another, is the very definition of arbitrary and capricious.

   EPA's refusal to meaningfully consider the "existing" NOx controls at Hunter and Huntington as a substantive part of its BART cost and visibility improvement analyses is forcibly contrary to EPA's statements and actions in Arizona, Colorado, Utah, the North Dakota decision, and the BART statute and Guidelines. EPA should withdraw its FIP Proposal and approve Utah's SIP Proposal.

B. **Costs**

Any BART determination must include an analysis of cost. 42 U.S.C. § 7491(g)(2). In the FIP Proposal, EPA states that it determined costs "in accordance with the BART Guidelines," the "EPA Air Pollution Control Cost Manual" ("CCM"), "portions of the draft 2015 revisions to the CCM chapters for the post-combustion NOx control technologies" related to SNCR and SCR, and "cost of compliance estimates supplied to EPA by Andover Technology Partners (ATP)" which in turn "rely on the cost estimates that PacifiCorp submitted to Utah in 2012 and 2014, but with those cost estimates adjusted in a number of cases for reasons described in the ATP report." See 81 FR at 2031-33. EPA's SCR cost estimates are flawed, particularly ATP's revisions to PacifiCorp's cost estimates and also because of EPA's departure from the existing CCM. EPA's NOx BART determinations in its FIP Proposal are flawed because they relied on ATP's flawed SCR cost estimates.

To identify and explain these flaws, PacifiCorp retained Sargent & Lundy ("S&L"),[44] a respected engineering firm that engineers and designs NOx pollution control devices,

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method to Hunter and Huntington that skews the "average cost-effectiveness number" and makes it incomparable to the same numbers at Hayden and Cholla. It is arbitrary and capricious to apply to different interpretations of the "existing controls" statutory requirement different power plants within PacifiCorp's system and to BART determinations EPA uses for comparison.

[44] S&L's experience in the electric power industry, as well as its experience working with PacifiCorp, made it uniquely qualified to perform a review of ATP's and EPA's SCR

such as SCRs. S&L generated a report ("S&L Report"), attached hereto as Attachment 5, which is hereby incorporated by reference. S&L identified several material mistakes made by ATP in generating its SCR cost estimates, which estimates EPA then relied on in its BART determinations and FIP Proposal. EPA also made its own independent mistakes in its SCR cost estimates.[45] As a result of ATP's and EPA's cost-estimating mistakes and misapplication of the applicable statutes and regulations, the EPA's BART cost estimates for SCR are vague, confusing, illegal, and wrong, and EPA's FIP Proposal should be rejected, for the following reasons.

1. *EPA's SCR BART cost estimates are missing required information* -- EPA claims that its SCR capital costs were obtained, in part, from PacifiCorp's 2014 BART Analyses. However, PacifiCorp's estimated SCR capital costs are much higher than EPA's estimated SCR capital costs. For example, in PacifiCorp's August 4, 2014 BART analysis, page 2, the estimated SCR capital costs for LNB/OFA/SCR are $180.8 million for Hunter Unit 1. S&L Report at 3, tbl. 1. EPA claims the estimated capital costs for LNB/OFA/SCR are $110.3 million for Hunter Unit 1. See 81 Fed. Reg. 2,004, 2,035 tbl 14. While EPA claims PacifiCorp improperly included certain costs (which claim is wrong), EPA never explains the $70 million difference between its SCR cost estimate and PacifiCorp's SCR cost estimate for Hunter Unit 1.[46] EPA must adequately support and document its BART cost analysis, which includes explaining the differences between PacifiCorp's August 2014 BART analysis costs and EPA's revised costs relied upon in the Proposed Rule. PacifiCorp cannot verify EPA's SCR cost estimates, which are reductions of PacifiCorp's SCR cost estimates, until EPA explains how it reduced PacifiCorp's cost estimates on an item by item basis. EPA's "actions must be reasoned." Nat'l Parks Conservation Ass'n v. E.P.A.,

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cost estimates. S&L has considerable experience with the federal and state environmental regulations affecting power plant operations, as well as the specification, evaluation, selection, and implementation of emission control technologies for both gas- and coal-fueled utility power facilities, including extensive experience with the NO_X control technologies evaluated. For example, since 2000, S&L has provided, or is currently providing, engineering services for the implementation of SCR systems on 68 units, totaling more than 36,000 MW of operating capacity. S&L's first-hand experience with NO_X control technologies, especially SCR systems, provides it with a thorough understanding of both the capital and operating and maintenance (O&M) costs associated with these technologies. In addition, S&L has completed multiple projects for PacifiCorp at both the Hunter and Huntington stations and is familiar with the site constraints and the potential challenges to construct SCR systems at each station.

[45] EPA made several obvious mistakes in its SCR cost estimates. For example, EPA's FIP Proposal rejects PacifiCorp's SCR cost estimates allegedly because they included improper items, such as AFUDC. See 81 FR at 2004, 2034-35. However, EPA's own expert stated "AFUDC is not included in the overnight cost methodology of the CCM and therefore was not allowed. PacifiCorp correctly excluded this from their estimate." ATP Report, page 10.

[46] Again, although PacifiCorp uses Hunter 1 as an example, EPA and ATP made the same SCR cost estimating mistakes at all of the Utah BART units. Therefore, all of the arguments made herein apply with equal force to all Utah BART Units.

788 F.3d 1134, 1141 (9th Cir. 2015). The law requires EPA to "cogently explain why it has exercised its discretion in a given manner." Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43 (1983); Gen. Chem. Corp. v. United States, 817 F.2d 844, 857 (D.C. Cir. 1987) (per curiam). Here, EPA has not cogently explained the difference between its SCR BART cost estimates and PacifiCorp's SCR cost estimates.

2. *EPA's cost estimates are contrary to the CCM* -- In the FIP Proposal, EPA states that "cost estimates for control technologies should be based on the CCM, where possible." See 81 FR at 2033. But EPA, and its expert, ATP, ignored certain costs allowed by the EPA Control Cost Manual ("CCM") when calculating SCR costs for the NOx BART determinations. For example, in the ATP Report, pages 7-8, EPA's expert discounted costs from PacifiCorp's SCR cost estimates that the same experts admit are allowed by the CCM. The ATP Report admits "PacifiCorp provided cost estimates that follow the general format of the 2002 CCM. Although the 2002 CCM shows a process contingency of 5% in Table 2.5 in Section 4.2 (page 2-44), this is not necessary today for SCR on coal-fired boilers firing the coals used in Utah." *Id.* In other words, ATP and EPA inappropriately disallowed SCR costs for process contingency that are explicitly authorized by the CCM. S&L estimates that improperly excluding the "process contingency" reduced EPA's SCR cost estimates by approximately $6 million per Utah BART Unit. S&L Report at 23, tbl 2. This cost is material and impacts the BART cost-effectiveness analyses.

But this is not all. ATP and EPA further skewed the SCR cost estimates relied on by EPA by disallowing general facilities costs, catalyst costs, and indirect installation costs -- all of which are specifically allowed by the CCM. It is improper for EPA to ignore SCR costs allowed by the CCM. See 79 FR at 5032, 5135 ("There are only very limited situations in which a state or EPA can depart from the CCM cost methodology. . . . The guidelines for BART determinations make it clear that the CCM is the intended methodology for conducting a BART cost determination. It also states why: To maintain and improve consistency.").

If ever this rationale applied to a regional haze plan, it applies to the FIP Proposal. In an attempt to validate its SCR-focused BART determinations in the FIP Proposal for the Utah BART Units, EPA compared the Utah BART Units' cost and visibility data with that from SCR-focused BART determinations for the Cholla power plant in Arizona, Laramie River power plant in Wyoming, and Hayden power plant in Colorado. See e.g., 81 FR at 2037. However, as EPA has admitted, such comparisons are meaningless unless the cost estimates are done in a consistent manner. Therefore, before EPA can make the alleged BART cost comparisons, it will need to show it made the same CCM adjustments to the cost estimates for the Cholla, Laramie River, and Hayden cost estimates. This it cannot do, and EPA should withdraw its FIP Proposal.

a. "Draft" changes to the CCM Don't Count -- Additionally, ATP and EPA incorrectly made changes to PacifiCorp's SCR cost estimates based on *draft*

changes to the CCM. See e.g., 81 FR at 2032 ("we have utilized portions of the draft 2015 revisions to the CCM chapters for the post-combustion NOx control technologies," including SCR). For example, ATP rejected S&L's and PacifiCorp's catalyst cost estimates, derived from experience and application of the appropriate cost estimation methods, partially due to ATP's application of the draft 2015 CCM revisions. See e.g., ATP Report at 13 (ATP used the 2015 draft CCM to calculate catalyst costs). EPA's actions are improper. EPA cannot rely on draft CCM changes that are still subject to rulemaking and subject to revision to reduce PacifiCorp's SCR cost estimates. EPA claims it follows the CCM to ensure consistency between BART determinations. See 79 FR at 5032, 5135 ("The guidelines for BART determinations make it clear that the CCM is the intended methodology for conducting a BART cost determination. It also states why: To maintain and improve consistency."). Using the draft 2015 CCM proposed revisions for the NOx BART determinations in the FIP Proposal when EPA knows those same revisions were not used for other BART determinations is highly inconsistent. Finally, given EPA's historic refusal to consider updated visibility modeling,[47] EPA's reliance on a draft revision to the CCM to formulate its SCR cost estimates for the BART NOx determinations is arbitrary and capricious.

3. *EPA's SCR BART Cost Estimates are Invalid* -- EPA admitted that it relied on the ATP Report for its SCR cost estimate information. See, e.g. 81 FR at 2035 (Hunter 1). However, the ATP Report was incorrect, and these mistakes carried over to EPA's BART cost analyses for the Utah BART Units.

a. *The ATP Report's cost comparisons are incorrect* -- As part of its Report, ATP considered "historical industry cost data . . . to determine if the costs were reasonable in the context of what has been reported at other facilities." ATP Report at 7. However, ATP's analysis was skewed because it relied upon comparisons with SCR units built at a much lower elevation (ignoring the increase in flue gas volume from higher elevation units, like Huntington and Hunter). See S&L Report, at 2-3. ATP also included cost data from the early 2000s, and then incorrectly escalated it using the CEPCI, which is an improper method. See S&L Report at 3-4. When the correct adjustments are made for elevation[48] and outdated cost information, ATP's SCR cost estimates are demonstrably too low, and are not representative of costs actually incurred for

[47] See 79 FR 5032, 5115 ("We did not use CALPUFF Version 6.4 because this version of the model has not been approved by EPA for regulatory use.")

[48] ATP's and EPA's failure to properly consider the impact site elevation has on SCR costs is surprising given that both made this same mistake with SCR cost estimates in Wyoming, and corrected it only after prompting through public comments. See 79 FR 5032, 5039 ("EPA revised the cost analyses from those found in the proposed rule based upon input from various commenters. Some of factors that caused us to revise our cost estimates included accounting for site elevation in the SCR capital cost. . . .").

recent SCR installations. See S&L Report at 4-5. However, PacifiCorp's SCR cost estimates, without ATP's and EPA's improper reductions, are representative of actual SCR costs. Id. at 5, fig. 1. In fact, PacifiCorp's SCR cost estimates, on a $/kw basis, are less than the 2013 SCR cost included in the ATP Report. Id. at 5. All of this information shows EPA's SCR cost estimates are unreasonable and flawed. Therefore, EPA's SCR cost estimates and related NOx BART determinations are likewise flawed.

b. *The ATP Report arbitrarily rejected "process contingency"* -- ATP argues that, although the CCM allowed the "process contingency" identified in PacifiCorp's cost estimates, it is outdated because SCR is a "well proven and well understood technology on a wide range of US coals." ATP Report at 7-8. However, as S&L explains, the lack of experience with western bituminous coals, particularly Utah coals, and the potential for vapor-phase phosphorous poisoning of catalyst for deep-stage burners, such as those at the Utah BART Units, justify the process contingency provided for in the CCM. See S&L Report, at 6-7. Moreover, ATP and EPA are essentially modifying the CCM without putting the same through the required notice and comment process, which neither ATP nor EPA can do. ATP's and EPA's rejection of the "process contingency" in PacifiCorp's SCR cost estimates was inappropriate.

c. *The ATP Report capriciously rejected "project contingency"*-- The ATP Report also rejected PacifiCorp's "15% project contingency" as excessive, and stated "no additional project contingency is allowed." ATP Report at 8-9. ATP claims the project contingency should not be allowed because it results in double counting, and because PacifiCorp's SCR cost estimates were "detailed estimates" instead of "study-level (class 4 or 5) estimates." Id. at 9. ATP essentially admits that a 15% project contingency is proper for certain categories of estimates, but claims that PacifiCorp's SCR cost estimates do not fall within these categories. Id. at 8. ATP is wrong. ATP improperly classified PacifiCorp's SCR cost estimates as "detailed estimates" for which a project contingency is not allowed, ignoring that such "detailed estimates" require completion of at least 30% of the engineering and the SCR system design and construction must have been awarded to a contractor. See S&L Report at 7-9. The level of engineering work done for PacifiCorp's 2014 SCR cost estimates for Hunter and Huntington is below 5% and no SCR system design and construction contract has been awarded. Id. at 8. Therefore, according to the parameters identified in the CCM, PacifiCorp's SCR cost estimates are definitely "study level" estimates and the 15% "project contingency" should be included in EPA's SCR cost estimates. Id. at 9. Moreover, ATP's concerns about "double counting" are misplaced and ATP did not identify any items it claims were double counted. Id. S&L estimates ATP's "project contingency" mistake changed the EPA's SCR cost estimates by approximately $22 million per Utah BART Unit. S&L Report at 23, tbl 2. EPA's and ATP's cost-estimating mistakes regarding the "project contingency" are material, and invalidate EPA's FIP Proposal.

d. *The ATP Report improperly refuses "general facilities costs"* -- In its SCR cost estimates, ATP refused to include a line item for "general facilities" to "avoid double counting." ATP Report at 9. ATP's refusal is incorrect for two reasons. First, S&L and PacifiCorp "correctly followed the example illustrated in Chapter 2 of the Control Cost Manual with respect to General Facilities." See S&L Report at 10. Second, much of the equipment "listed in S&L's estimate to which Andover objects is safety related and included to protect the operating personnel. This equipment is required by the process and contributes directly to the physical capital costs." Id. ATP's example of "double counted" costs are unclear, and confusing. Id. S&L estimates ATP's "general facilities" mistake changed EPA's SCR cost estimates by approximately $6 million per Utah BART Unit. S&L Report at 23, tbl 2. EPA's and ATP's cost-estimating mistakes regarding the "general facilities cost" are material, and invalidate EPA's FIP Proposal.

e. *ATP incorrectly disallowed "indirect installation costs"* -- ATP disallowed certain "indirect installation costs," again alleging that such costs were double counted. ATP Report at 11. ATP is wrong again. PacifiCorp's SCR cost estimates were already adjusted to avoid double counting and PacifiCorp followed the CCM when addressing indirect installation costs. See S&L Report at 12-14. Despite the fact that indirect installation costs are real world costs that PacifiCorp will incur if required to install SCR, PacifiCorp followed the CCM and excluded the required costs. Id. S&L estimates ATP's "indirect installation cost" mistakes changed the EPA's SLR cost estimates by approximately $5.7 million per Utah BART Unit. S&L Report at 23, tbl 2. EPA's and ATP's cost-estimating mistakes regarding the "indirect installation costs" are material, and invalidate EPA's FIP Proposal.

f. *ATP, and EPA by extension, illegally redesigned the SCR and incorrectly underestimated catalyst costs.*ATP illogically adjusted PacifiCorp's SCR cost estimates based on ATP's incorrect analyses of catalyst cost, catalyst volume and life span, SCR reactor design, and use of regenerated catalyst. ATP Report at 14-20. ATP's assumptions lack any proper engineering basis, and are completely incorrect. First, PacifiCorp's catalyst cost estimates were based on the CCM, and as such should be allowed. See S&L Report at 14. Moreover, ATP's claim that PacifiCorp adjusted catalyst costs by improperly using the CEPCI is wrong; ATP misinterprets how PacifiCorp calculated catalyst costs. Id. at 14-15. Additionally, ATP's catalyst cost number is an arbitrary number that omits real world costs, such as freight costs or labor to load the catalyst into the SCR reactors. Id. at 15. EPA cannot rely on such arbitrary numbers. PacifiCorp's catalyst cost numbers were based on S&L's experience with recent catalyst pricing received from industry vendors, which include freight costs and installation. Id. Moreover, PacifiCorp's catalyst costs are lower than those used in the examples in the CCM and in EPA's fact sheet, cited by ATP. Id. S&L's replacement catalyst costs were extremely conservative, and less than the CCM would allow. Id. Therefore, PacifiCorp's catalyst costs estimates are reasonable, and EPA's are not.

Regarding catalyst life and volume, ATP is again wrong. "The amount of SCR catalyst volume required depends on the following design parameters: 1) gas volume, 2) gas temperature, 3) Amount of NOx removed, 4) catalyst life, 5) fuel properties (which dictate the deactivation rate), and 6) SO2 to SO3 oxidation rate. The data included in Andover's report that they use to conclude S&L's catalyst volume is over-estimated contains only one of these variables (catalyst life)." See S&L Report at 16. Therefore, ATP's catalyst volume estimates are based on incorrect assumptions. Also, ATP's catalyst life data did not include units designed with 32,000 hours of life, which is the design life of Hunter and Huntington SCR reactors. Id. Instead, ATP relied on units designed for 16,000 hours of catalyst life. Id. Also, ATP incorrectly included "gross output (MW), which is not directly proportional to gas volume in the case of the Hunter and Huntington units, each of which are over 5,600 feet in elevation, and as previously discussed, have significantly higher gas volumes for equivalently rated units located at sea level. For this reason, gross output (MW) cannot be used to compare catalyst volumes for plants that vary in elevation." Id. Additionally, ATP incorrectly calculates catalyst volume and cost by using a NOx % reduction number, when catalyst volume depends on the gross amount of NOx removed, not the percentage of NOx reduction. Id. ATP also mistakenly estimated that catalyst deactivation rate would be similar to Eastern Bituminous coal, instead of Western Bituminous coal (which is a more conservative assumption given the "unknowns" involved in using Utah coal). Id. at 17. ATP's mistakes have caused it to reject PacifiCorp's correct SCR cost estimates, including catalyst costs, and replace them with ATP's incorrect estimates. Moreover, PacifiCorp's catalyst volume and life estimates were based on the work done by S&L for PacifiCorp's Naughton Unit 3 SCR project in Wyoming, and represent practical, relevant and market-based cost estimation experience. ATP was wrong to ignore this data. Id.

Also, ATP erroneously claims one SCR reactor can be used instead of two, thereby saving significant costs. ATP Report at 16-18. ATP's error is based on its fundamental misunderstanding: SCR design is based on the volume of catalyst. ATP's assumption is completely wrong. Rather, SCR reactor design is primarily based on gas flow and velocity. See S&L Report at 19. ATP's attempted redesign to one SCR reactor is technically infeasible, resulting in inadequate "residence time" to achieve the required NOx reduction and causing the catalyst to erode in a very short time, rendering the SCR useless. Id. EPA cannot base its SCR cost estimates on an SCR system redesign that is technically infeasible, and would defeat the very purpose of the SCR system. Moreover, neither ATP nor EPA provides a supportable engineering basis for ATP's attempted redesigns of the SCR reactors.

Finally, ATP objects to PacifiCorp's SCR cost estimates by claiming that PacifiCorp should have used the costs for regenerated catalyst, instead of new catalyst. ATP Report at 11. S&L has participated "in several catalyst replacement projects in the last year and in each of these projects new catalyst was purchased

for the spare or replacement layer. In addition, due to mechanical degradation of the modules, which cannot be recovered, the mechanical life of regenerated catalyst is much lower than new catalyst and has not been guaranteed to meet the duration which the catalyst is typically expected to remain within the reactor." S&L Report at 20. Therefore, ATP should not have rejected PacifiCorp's SCR cost estimates because it did not use regenerated catalyst.

S&L estimates ATP's SCR design mistake and catalyst cost underestimations changed EPA's SCR cost estimates by approximately $18.5 million per Utah BART Unit. S&L Report at 23, tbl 2. EPA's and ATP's cost-estimating mistakes regarding the SCR redesign and catalyst costs are material, and invalidate EPA's FIP Proposal.

g. *ATP wrongly modified ID fan costs in the SCR cost estimates*.ATP claims that PacifiCorp overestimated the costs of ID fans because a smaller fan could be used. ATP Report at 18-19. ATP estimated the cost of the replacement fan by using an algorithm, rather than obtaining a vendor cost estimate. Id. ATP's ID fan cost estimates are wrong because the new ID fans must handle the entire flue gas flow and be designed to overcome the additional pressure drop from the SCR and the original differential pressure it was designed for (e.g., air preheaters, ESPs, etc.). See S&L Report at 20-21. EPA cannot base its SCR cost estimates on undersized fans.

S&L estimates ATP's ID fan mistake cost underestimations changed EPA's SCR cost estimates by approximately $875,000 per Utah BART Unit.

h. *ATP's and EPA's SCR cost estimation mistakes materially affected EPA's NOx BART determinations.* Each of the cost estimation mistakes discussed above in paragraphs a-g materially impacted EPA's NOx BART cost estimates. For example, ATP's SCR cost estimate errors result in over $70 million in excluded capital costs at Hunter Unit 1. See S&L Report at 23, tbl. 2. ATP's mistakes also resulted in it miscalculating operation and maintenance expenses for the Utah BART Units. Id. As a result, EPA's NOx BART determinations (which rely on ATP's incorrect SCR cost estimates) in its FIP Proposal are flawed and the FIP Proposal should be withdrawn. The cost estimation mistakes identified above in paragraphs a-g materially affect the overall cost of the proposed SCRs, and thereby would also materially affect the "average cost effectiveness" and "incremental cost effectiveness" numbers used by EPA in its justifications for the NOx BART determinations requiring installation for SCR.

4. *EPA's cost comparison numbers are inconsistent and do not support EPA's "cost effectiveness" finding.* As part of an analysis of the "cost" BART factor, a state or EPA needs to determine the "average cost effectiveness" and "incremental cost effectiveness" of the proposed BART control, and then determine if such costs are appropriate given the "reasonable anticipated" visibility improvement. See, e.g., 81 FR at 2037 (Hunter 1). In the FIP Proposal, EPA considered "the costs of compliance

and visibility impacts by generally comparing them with BART determinations that have been made elsewhere." Id. For example, EPA compared the average and incremental cost effectiveness of SCR at Hunter Unit 1 to average and incremental cost effectiveness numbers for SCR at other, purposefully-selected units: Laramie River Station (Wyoming); Dave Johnston Units 3 and 4 (Wyoming); Hayden Units 1 and 2 (Colorado); and Cholla Units 2, 3, and 4 (Arizona).

Using these four facilities, EPA attempts to create a false standard, acting as if the BART determinations for these facilities are reflective of general cost effectiveness and visibility improvement standards everywhere. This simply isn't true for several reasons.

First, EPA ignores its own "cost effectiveness" standards used to create the presumptive BART limits, which EPA still uses when setting BART benchmarks for Better than BART analyses. For example, Appendix Y suggests that BART NOx control costs above $1,500 per ton are not "cost effective." In the Preamble to the Regional Haze Rules, EPA suggested that 75% of the EGUs would have BART NOx removal costs between $100 and $1,000 per ton, and almost all of the remaining EGUs could install sufficient BART NOx control technology for less than $1,500 per ton.[49] EPA also recognized in the Preamble that SCR was generally not cost effective for EGUs, except for EGUs with cyclone boilers (where the cost per ton was less than $1,500 per ton, with an average of $900 per ton).[50] Based upon EPA's Preamble, BART NOx control technology that costs more than $1,500 per ton should not be considered "cost effective." Here, EPA found BART NOx controls with a "cost effectiveness" number several times $1,500 per ton to be "cost effective." EPA

[49] "The limits provided were chosen at levels that approximately 75 percent of the units could achieve with current combustion control technology. The costs of such controls in most cases range from just over $100 to $1000 per ton. Based on our analysis, however, we concluded that approximately 25 percent of the units could not meet these limits with current combustion control technology. However, our analysis indicates that all but a very few of these units could meet the presumptive limits using advanced combustion controls such as rotating opposed fire air ("ROFA"), which has already been demonstrated on a variety of coal-fired units. Based on the data before us, the costs of such controls in most cases are less than $1500 per ton." See 70 FR at 39135.

[50] "We also analyzed the installation of SCRs at BART-eligible EGUs, applying SCR to each unit and fuel type. The cost-effectiveness was generally higher than for current combustion control technology except for one unit type, cyclone units. Because of the relatively high NO[x] emission rates of cyclone units, SCR is more cost-effective. Our analysis indicated that the cost-effectiveness of applying SCR on coal-fired cyclone units is typically less than $1500 a ton, and that the average cost-effectiveness is $900 per ton. As a result, we are establishing a presumptive NO[x] limit for cyclone units based on the use of SCR. For other units, we are not establishing presumptive limits based on the installation of SCR. Although States may in specific cases find that the use of SCR is appropriate, we have not determined that SCR is generally cost-effective for BART across unit types." 70 FR 39135-36.

simply ignores its previous statements when attempting to establish its newly-minted cost-effectiveness threshold.

Second, EPA pointed only to BART determinations that support its position. EPA has ruled that NOx BART controls, including SCR, with similar "cost effectiveness" numbers as it found for the Utah BART Units were not justified. For example, EPA approved Florida's BART determination that installing SCR was not "cost effective" when it would cost $3,776/ton of NOx removed. See 77 FR at 73369-01, 73377. Additionally, in Montana, EPA found that where SNCR+SOFA had an average "cost effectiveness" of $3,195/ton and $3,235/ton, the incremental "cost effectiveness" of SCR+SOFA of $5,770/ton and $5,887/ton "is not justified." See 77 FR at 57864-01, 57889. Also, in Nebraska, EPA proposed to agree with Nebraska's decision to reject SCR at an average cost effectiveness of $2,297/ton and an incremental cost effectiveness of $5,445/ton (as calculated by Nebraska). See 77 FR at 12770, 12779. If EPA had selected these comparisons, or others,[51] it would reject SCR as NOx BART at the Utah BART Units. EPA cannot "cherry-pick" favorable comparisons while ignoring unfavorable comparisons in its attempt to create the illusion of legitimacy for its NOx BART determinations in the FIP Proposal.[52]

EPA attempts to use its "cherry picked" SCR BART determinations as a "metric" that a reader could use to understand how EPA determined BART. Nat'l Parks Conservation Ass'n, 788 F.3d at 1143. But EPA's previous SCR BART determinations and statements cannot serve as a reliable metric: they are too inconsistent. Id. at 1141 (stating that "inconsistent analysis is arbitrary and capricious"). A reader who reviewed all of EPA's prior NOx BART determinations would be left entirely unable to predict at what price point EPA will determine that a control technology is not cost effective, or what amount of modeled visibility improvement will trigger a certain technology, or what combination of cost and visibility numbers would result in the installation of SCR as BART. This stems not only from EPA's inconsistent determinations, but from EPA's stated unwillingness to provide a bright-line test for determining when a control technology is "cost effective." See 77 FR at 57864-01 ("While the Regional Haze Rule may allow us to establish a bright line for some of the factors such as cost-effectiveness and visibility, we are not required to do so, and have not done so for this action."). Further, EPA's BART determinations rely on its previous determinations in an entirely arbitrary and

[51] EPA previously approved Colorado's RH SIP in which Colorado determined that SCR is not cost effective when it "exceed[s] a cost of $5,000 per ton." 77 FR 18052-01, 18061. Though EPA noted some concerns it had with Colorado's reasoning, it ultimately approved its determinations, implicitly approving Colorado's determination that SCR is not cost effective when it exceeds $5,000/ton. Id.

[52] Moreover, comparisons with SCR BART determinations for Cholla and Laramie River are suspect for another reason. In both cases, EPA's SCR BART determinations have been challenged in court and are subject to judicial review. EPA cannot rely on SCR BART determinations that have judicially challenged and have not yet been upheld by a court.

capricious manner, skewing the results by selecting favorable SCR BART comparisons and ignoring unfavorable ones. A metric which conforms to the whims of EPA's current desires is no metric at all. Therefore, EPA should withdraw its FIP Proposal.

Third, EPA's attempted cost and visibility data comparisons between the Utah BART Units, on the one hand, and Cholla, Hayden, and Laramie River, on the other hand, would only work if the SCR cost estimates, visibility analyses, and baseline emissions tests, among other things, were conducted in a similar manner. See e.g., 79 FR at 5032, 5156 ("A proper evaluation of cost-effectiveness allows for a reasoned comparison not only of different control options for a given facility, but also of the relative costs of controls for similar facilities. If the cost-effectiveness of a control technology for a particular facility is outside the range for other similar facilities, the control technology may be rejected as not cost-effective. *In order for this type of comparison to be meaningful, the cost estimates for these facilities must be performed in a consistent manner. Without an "apples-to-apples" comparison of costs, it is impossible to draw rational conclusions about the reasonableness of the costs of compliance for particular control options*.") (emphasis added) However, that is not the case. As explained above, the baseline emissions for Cholla and Hayden were calculated based upon the emissions reductions from relatively recently installed NOx emissions control equipment; here EPA refuses to calculate baseline emissions based upon emissions reductions from relatively recently installed NOx emissions control equipment at the Utah BART Units. EPA also conducted its CALPUFF visibility modeling differently for the Cholla, Hayden, and Laramie River BART determinations, which could materially impact the outcomes.[53] Also, ATP and EPA refused to consider certain CMM allowed costs and its expert "redesigned" the SCR reactors for Hunter and Huntington. EPA did not take the same SCR cost-estimating approach at Cholla, Hayden, or Laramie River.[54] As a result, EPA cannot compare costs between the Utah BART Units and EPA's "cherry-picked" units because EPA

[53] Given the unique manner in which EPA conducted the CALPUFF visibility modeling for the FIP Proposal, it is highly unlikely that EPA conducted the CALPUFF modeling for SCR at Hayden, Laramie River, or Cholla in this same fashion. If the CALPUFF modeling for Hayden, Cholla, and Laramie River were not completed in the same manner as Hunter and Huntington, using the same background concentrations for ammonia, relative humidity, and other key inputs, as well as the way manner in which the model included other sources, then EPA is unable to make meaningful comparisons between the CALPUFF modeling results. In its FIP Proposal, EPA makes no attempt to explain whether or not the CALPUFF modeling runs were conducted in a similar fashion for the Cholla, Hayden, and Laramie River plants on the one hand and the Utah BART Units on the other hand.

[54] Other material differences exist between the cost estimates EPA attempts to compare. For example, EPA, after prompting from Laramie River's owner, considered the impact site elevation has on SCR cost. 79 FR 5032, 5180. EPA has not properly considered the impact site elevation has on SCR costs at the Utah BART Units.

used different and inconsistent methods to calculate SCR costs and visibility improvement, making comparisons superficial and unpersuasive.

C. **Energy and Non-Air Quality Environmental Impacts.**

Each BART determination, including EPA's, must include a review of the energy and non-air quality related environmental impacts. 42 U.S.C. § 7491(g)(2). EPA's FIP Proposal is defective because EPA failed to properly evaluate the "energy" and "non-air quality environmental" factors for the Utah BART Units. Utah's previous BART determinations found these impacts weighed against SCR as NOx BART; but, without explanation or conducting its own analyses, EPA found these impacts did not prohibit the selection of SCR. This EPA cannot do.

1. *The BART Guidelines require this factor be considered.* The BART Guidelines provide the methods EPA must employ when considering the energy and non-air quality environmental impacts of NOx control options in a BART determination. See 70 FR at 39104-01, 39169. Among other considerations, the BART Guidelines provide that EPA "should identify any significant or unusual environmental impacts associated with a control alternative that have the potential to affect the selection or elimination of a control alternative." Id. The Guidelines elaborate that "these types of environmental concerns become important when sensitive site-specific receptors exist *or when the incremental emissions reductions potential of the more stringent control is only marginally greater than the next most-effective option*." Id. Given that EPA's FIP Proposal is based on a miniscule, modeled 0.14 dv visibility improvement over the SIP Proposal, based on the 98th percentile test, this provision of the Guidelines is particularly applicable and non-air quality environmental impacts and energy impacts must be closely reviewed as part of EPA's NOx BART determinations for the Utah BART Units. EPA failed to do so here.

2. *EPA did not properly analyze non air quality environmental impacts.* Here, EPA arbitrarily and capriciously failed to adequately address the non-air quality environmental impacts of SCR. See, e.g. 81 FR at 2004, 2035 (Hunter 1).[55] Though EPA admitted that SCR decreases the thermo efficiency (affecting energy use and greenhouse gas emissions) and increases "the quantity of ash that will need to be disposed," EPA conducted almost no analysis. Id. at 2035. EPA did not identify or quantify the "solid, liquid, and gaseous discharges from the control device or devices under review," as required by the Guidelines. See 70 FR at 39104-01, 39169. EPA did not analyze "discharges with potential for causing adverse environmental effects." Id. Nor did EPA "assess the mass and composition of any such discharges and quantify them to the extent possible based on readily available information." Id. Rather, after conducting almost no analysis, EPA concludes that "non-air quality environmental impacts [are] insufficient to eliminate or weigh against any of the

[55] While PacifiCorp uses Hunter 1 as an example of EPA's failure to consider the energy and non-air quality environmental impacts, these arguments apply to EPA's NOx BART determinations for all the Utah BART Units.

BART options." See 81 FR at 2004-01, 2035. This conclusion, lacking sufficient supporting analysis, violates EPA's own rules. By failing to provide any applicable metric, failing to explain why it has exercised its discretion in this manner, and failing to follow the BART Guidelines, EPA's proposed RH FIP is arbitrary and capricious and should be withdrawn. Nat'l Parks Conservation Ass'n, 788 F.3d at 1141.

Moreover, EPA's SCR cost estimates are based upon a complete redesign of the SCR system, and are materially different from that contemplated by PacifiCorp's and Utah's SCR BART analyses. See ATP Report at 11-18. Therefore, EPA cannot rely on PacifiCorp's and Utah's previous SCR BART analyses to determine the non-air quality environmental and energy impacts for EPA's SCR BART determinations. New analyses of this statutory BART factor, in accordance with the BART Guidelines, must be undertaken by EPA to address the proposed SCR reactor design that it proposes.

3. *EPA did not properly consider SCR's energy impacts*. In its FIP Proposal, EPA should have considered three types of energy impacts. These include the energy associated with operating the controls, the energy that must be provided when the unit is removed from service in order to install the controls, and most importantly to the state of Utah and its citizens, the energy that must be replaced when the emissions controls prescribed for a given unit are not economically justifiable and result in accelerated unit retirements and replacements.[56]

The latter energy impact is of particular concern because the EPA has now proposed SCR controls for the Utah BART Units. Unlike the SIP Proposal, the EPA's FIP Proposal requires controls that may not be justifiable and could result in accelerated unit retirements and replacements, potential natural gas conversions, and the associated costs and socio-economic impacts of removing major coal-fueled generation resources from service in areas of Utah that rely heavily on these facilities. If EPA intends to finalize its FIP Proposal that potentially could force the retirement, replacement, or natural gas conversion of the Utah BART Units, its five-factor analysis must include a thorough analysis of the system-wide energy impacts these individual unit compliance requirements will have on the states within which PacifiCorp serves customers. When considering the FIP Proposal, EPA must include in its evaluation of energy impacts and their associated costs the impacts to local jobs and state and local economies surrounding the affected facilities.

With retirement, replacement, or natural gas conversion of individual units a potential outcome due to EPA's FIP Proposal, EPA's assessment must include coordination with state regulators, environmental agencies and elected officials. As a regulated utility, PacifiCorp regularly engages with state regulators and elected officials to ensure that its resource planning and ultimate compliance approaches align with the interests of customers in the states it serves. These same state bodies and elected

[56] 40 CFR 50 Appendix Y D.IV.h.5

officials must be consulted by EPA to ensure that EPA's FIP Proposal is properly assessed in light of the issues described above.

As Powder River Basin Resource Council pointed out in its post-hearing brief filed in April 2013 before the Wyoming Public Service Commission in PacifiCorp's application filing to obtain approval for a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction systems on Jim Bridger Units 3 and 4, "it is evident that considering the cost and risk of these major environmental control projects up front, prior to installation, is a benefit to parties, ratepayers, and the public interest. These projects are significant undertakings – in some cases they are close to the financial equivalent of building new generation sources – and therefore they deserve a high level of scrutiny to ensure that the public's interests, and especially the specific financial interests of PacifiCorp ratepayers, are protected."[57] EPA is expected to obtain the same level of coordinated review.

D. Visibility Improvement

Every BART determination requires an analysis of the "reasonably anticipated" visibility improvements. 42 U.S.C. § 7491(g)(2). EPA's BART visibility improvement analyses for its FIP Proposal fail in several respects, and thus fail to meet the statutory requirements.

When EPA conducted its "reasonably anticipated" visibility improvement analyses for its NOx BART determinations of the Utah BART Units, EPA relied exclusively on computerized modeling results, using the CALPUFF model. See 81 FR at 2033. EPA did not use Utah's previous CALPUFF modeling to support its FIP Proposal,[58] instead EPA

[57] See Powder River Basin Resource Council's Post-Hearing Brief in Wyoming Public Service Commission Docket No. 20000-418-EA-12 (RECORD NO. 13314) at: http://edocs.puc.state.or.us/AD9EAE92-D6A8-4C0E-81D1-DB442CFB2244/FinalDownload/DownloadId-DCE8BAB12B5061CB4017455D76704E32/AD9EAE92-D6A8-4C0E-81D1-DB442CFB2244/efdocs/HBC/ue246hbc75023.pdf

[58] Proper conclusions can be reached when evaluating the results of visibility modeling if one understands the limitations of the models, the characteristics and limitations of the inputs entered into the models, the capabilities of the model versions being used and then applies reasonable judgment to the results. Utah created its SIP Proposal based on the modeling protocols and versions required by EPA. In proposing its SIP Proposal, Utah evaluated the CALPUFF model output with an understanding of the model's limitations. Utah then applied its judgment and experience in comparing the model results to actual monitored data, as encouraged by EPA's guidelines and the CAA. Utah's approach helped mitigate the problems associated with the CALPUFF visibility model's documented tendency to greatly over-predict the visibility improvement associated with BART controls. In fact, Utah analyzed other scientific data to determine the impacts of SO2 and NOx emissions from the BART units, and used that information in determining the amount of weight to give CALPUFF modeling results. Contrary to this approach, EPA interpreted the CALPUFF modeling results as "absolute" and unquestioningly accurate numbers that EPA then relies on to justify costly NOx BART controls that in reality will provide no "reasonably anticipated" visibility benefit.

"developed separate CALPUFF modeling for this purpose." *Id.* In fact, although Utah's CALPUFF modeling assessed the "combined impacts of all of the BART and non-BART sources included in the BART Alternative," EPA mistakenly only modeled "the impacts of the individual BART sources." *Id.* EPA also claims that, beyond "assessing impacts from individual BART sources and evaluating all technically feasible control options," EPA's modeling was "otherwise very similar to that employed by Utah." *Id.* Again, EPA is mistaken.

In short, EPA's NOx BART determinations in its FIP Proposal, particularly the visibility analyses, are fatally flawed because EPA relied on CALPUFF modeling results without considering: (1) the limitations of the CALPUFF v. 5.8 model; (2) the CALPUFF model's related "margins of error;" (3) EPA's mistakes running the CALPUFF model; and (4) actual monitored data and other data that called into question EPA's ability to solely rely on the CALPUFF modeled results without accounting for the model's limitations.

1. *EPA failed to consider the limitations of the CALPUFF model.* In conducting its BART visibility improvement analyses for the Utah BART Units in the FIP Proposal, EPA treats the relative small CALPUFF modeled visibility improvements as concrete and unassailable. See e.g., 81 FR at 2035 tbl. 15; at 2036 tbls. 16, 17, and 18; at 2037 (for the Hunter 1 Unit).[59] EPA relies solely on CALPUFF modeled visibility improvements as the basis for its visibility improvement analyses in the FIP Proposal. See, e.g., 81 FR at 2037. However, EPA's BART visibility analyses in the FIP Proposal fail to recognize the known and documented limitations on the CALPUFF model. Rather, EPA treats the results from the CALPUFF visibility modeling as being capable of accurately predicting visibility improvements down to the tenths or hundredths of a deciview (when one deciview is considered what is humanly perceptible). As applied by EPA here, the CALPUFF model is not that accurate. Also, EPA assumes that a CALPUFF modeled difference of 0.1, 0.2, an even 0.9, deciviews is material in the FIP Proposal. Given the applicable margins of error, it is not. The reality is that computer models predicting visibility impacts from a given source, including CALPUFF, are relatively imprecise and easily influenced by the choice of inputs and parameters.

a. CALPUFF is woefully imprecise. Gale F. Hoffnagle, an expert air quality modeler at TRC Environmental Consultants,[60] summarizes in his report, attached as Attachment 3, the limitations of the CALPUFF model.[61] Mr. Hoffnagle's

[59] EPA treats the CALPUFF modeled visibility improvement results as concrete and unassailable for all the Utah BART Units, and the arguments herein regarding EPA's visibility improvement analyses apply to all of the Utah BART Units.

[60] Mr. Hoffnagle's curriculum vitae is attached as Attachment 6.

[61] Mr. Hoffnagle is a CALPUFF modeling expert. His CALPUFF "margin of error" report was part of the information that the Ninth Circuit Court of Appeals found EPA should have considered and accounted for in Nat'l Parks. In that case, the court stated "it is no answer to respond, as EPA did, that low levels of visibility impairment must be

Report states that the studies EPA relied upon to support the use of CALPUFF (v. 5.8) model for regional haze purposes demonstrate that the CALPUFF results (at 100km) were "35%, 5%, or 250% too high, average 96% too high and has a mean error rate of 96%." See Hoffnagle Report at 6. In other words, some of the studies EPA relied on to justify the use of the CALPUFF v. 5.8 model show CALPUFF grossly overstates visibility improvements. Mr. Hoffnagle further explains that two other studies (Savannah River and Great Plains) used by EPA to justify the use of the CALPUFF v 5.8 model show that "there is an error rate of 79% and always greater than the measured concentration." Id. at 7. "The 'margin of error' identified in the aforementioned studies is hereafter referred to as the 'transport/diffusion margin of error' because these studies measured CALPUFF v. 5.8's accuracy relative to long-range transport and diffusion." Id. Additional studies and reports have also raised questions about the transport/diffusion margin of error for CALPUFF, and a review of all the studies together by Environ suggests the transport/diffusion margin of error "for CALPUFF version 5.8 is around 70% for the maximum observed concentration with many signals that the error is higher. The error is always on the high side and we can say little about the margin of error beyond 100 kilometers." Hoffnagle Report at 8-9. Clearly, EPA cannot, as it did in its FIP Proposal, simply rely on CALPUFF's excessively high, modeled results in light of the transport/diffusion margin of error. Instead, EPA should have made appropriate adjustments in its analysis of the CALPUFF modeled results to account for the transport/diffusion margin of error so that EPA "reasonably anticipates" any visibility improvements associated with EPA's proposed NOx BART determinations. 42 U.S.C. § 7491(g)(2); Nat'l Parks Conservation Ass'n, 788 F.3d at 1147. EPA did not do so here.

b. EPA did not account for "atmospheric chemistry margin of error" .CALPUFF also has severe limitations in modeling the atmospheric chemical changes that are necessary for NOx to become a visibility-impairing particulate. As Mr. Hoffnagle's Report explains, the "margin of error is also affected by the atmospheric chemistry which occurs along the path to the Class I area." See Hoffnagle Report at 9. As an expert in this area, Mr. Hoffnagle has previously "performed and presented to the State of Colorado a comparison of the measured versus modeled nitrate component of the deciview impact from the Craig Station some 98 kilometers to the Mount Zirkel Wilderness Area." Id. Mr. Hoffnagle compared "the daily nitrate concentration measured at the Mount Zirkel Wilderness Area to the CALPUFF modeled daily concentration of nitrate particles at that measurement location." Id. As a result of this study, Mr. Hoffnagle concluded that CALPUFF's atmospheric chemistry margin of error in that study

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addressed even though they are not perceptible to the human eye, or that measures had been taken to minimize the margin of error. The issue is not the *perceptibility* of the proposed improvements, but the model's ability to anticipate improvements at a level allegedly within its margin of error, whether perceptible or not to the human eye. EPA simply offered no response to this objection." Nat'l Parks Conservation Ass'n v. E.P.A., 788 F.3d 1134, 1147 (9th Cir. 2015).

was "at least 1,000% in calculating nitrate contribution to visibility impairment. This is a clear indication that the margin of error increases substantially when the atmospheric chemistry part of the calculation is included." Hoffnagle Report at 10. Again, EPA's FIP Proposal failed to account for either the transport/diffusion margin of error or the atmospheric chemistry margin of error, and EPA blindly relies on overstated CALPUFF modeling results without any adjustments for model inaccuracies. As a result, EPA's FIP Proposal is unsupportable and should be withdrawn. See Nat'l Parks Conservation Ass'n, 788 F.3d at 1147.

c. The transport/diffusion and atmospheric chemistry margins of error materially change EPA's visibility analyses . When the appropriate "margins of error" are applied to EPA's CALPUFF modeling results in the FIP Proposal, the alleged "substantial visibility benefits" (81 FR at 2038) EPA relied on to justify its FIP Proposal disappear. For example, EPA's CALPUFF modeled visibility improvement results related to the installation of LNB/OFA/SCR (EPA's NOx BART determination) at Hunter Unit 1 indicate a 1.34 dv improvement at Arches, 1.55 dv improvement at Canyonlands, and a 1.11 dv improvement at Capitol Reef. See 81 FR 2 035, tbl 15. These results lead EPA to conclude the comparisons "show that costs are justified in light of the substantial visibility benefits." Id. at 2038. However, these "substantial visibility benefits" disappear when the proper "margins of error" are applied. In Mr. Hoffnagle's Report, after applying the transport/diffusion margin of error and the atmospheric chemistry margin of error, the CALPUFF modeled visibility improvements shrink to an inconsequential 0.16 dv for Arches, 0.18 dv for Canyonlands, and 0.16 dv for Capitol Reef. See Hoffnagle Report at 19, tbl 8. Likewise, EPA's CALPUFF modeled visibility improvement results related to the installation of LNB/OFA/SCR (EPA's NOx BART determination) for Huntington Unit 1 indicate a 1.49 dv improvement at Arches, 1.88 dv improvement at Canyonlands, and a 1.11 dv improvement at Capitol Reef. See 81 FR 2043, tbl. 27. In Mr. Hoffnagle's Report, after applying the transport/diffusion margin of error and the atmospheric chemistry margin of error, the visibility improvements shrink to an inconsequential 0.15 dv for Arches, 0.19 dv for Canyonlands, and 0.12 dv for Capitol Reef. See Hoffnagle Report at 19, tbl 9. Clearly, these miniscule visibility improvements would not justify the tremendous costs imposed by EPA's FIP Proposal. EPA's FIP Proposal is flawed and unsupportable because it failed to consider the CALPUFF modeled visibility improvement results in light of the proper margins of error, which drastically affect the results.[62] At least one federal

[62] Additionally, the monitored data demonstrates that the SCRs required by the FIP Proposal essentially would have no impact. EPA found in its proposed rulemaking that "visibility benefits associated with NOx reductions are more likely to occur in the winter months because this is when aerosol thermodynamics favors nitrate formation." 81 FR at 2031. Therefore, the SCRs that would be required by EPA's FIP Proposal, which are designed to reduce NOx, would be of greatest benefit in the winter months. However, EPA fails to recognize or consider the monitored data which demonstrates that nitrates have very little impact on visibility impairment during the 20% best days, which often

court has rejected an EPA regional haze FIP because EPA failed to account for the CALPUFF model's limitations (specifically the margin of error) when EPA formulated its BART determinations. Nat'l Parks Conservation Ass'n v. E.P.A., 788 F.3d 1134, 1147 (9th Cir. 2015). Therefore, EPA's FIP Proposal should be withdrawn.

d. EPA should have used the improved CALPUFF version. CALPUFF version 5.8.4, used by EPA to support its FIP Proposal, is not the latest and most accurate version of CALPUFF. As Mr. Hoffnagle explains, the owners of CALPUFF "have prepared more advanced versions of CALPUFF that have not been adopted by EPA. The focus of these advancements have been in providing better atmospheric chemistry based on twenty years of advancement in atmospheric chemistry science. AQMG [EPA] has steadfastly refused to give anything more than acknowledgement to these advancements and yet continuously criticizes CALPUFF for not having advanced chemistry." See Hoffnagle Report at 7.

Air modeling experts have determined that CALPUFF version 6.42, with a variable ammonia background setting, updated chemistry module, and Method 8 of CALPOST is the "best" science when it comes to modeling for regional haze. CALPUFF Version 6.42 produces more realistic and accurate results. *See* Paine, B, Connors, J, "Response to Prehearing Statements: Martin Drake Power Plant Best Available Retrofit Technology Rulemaking Hearing," November 20, 2010, attached as Attachment 7. Version 6.42 contains needed refinements, such as a better "chemistry" module known as ISORROPIA (Version 2.1). Id. Additionally, CALPUFF Version 6.42 has been maintained by TRC and has had many bug fixes and enhancements not included in CALPUFF Version 5.8.4. Id.

Contrary to its own guidance, in support of its FIP Proposal EPA failed to use a more realistic air quality model (CALPUFF version 6.42) than the outdated CALPUFF version 5.8. Appendix W, EPA's modeling guidance, demands that the "best" model should be used. EPA failed to use the "best" model in its FIP Proposal. Therefore, EPA failed to follow Appendix W's requirements. App. W.1.0.e ("(I)n all cases, the model applied to a given situation should be the one that provides the most accurate representation of atmospheric transport, dispersion, and chemical transformations in the area of interest."); App. W.1.0.d ("The model that most accurately estimates concentrations in the area of interest is always sought.") (emphasis added). EPA's outdated modeling approach relying on CALPUFF version 5.8.4, fails to meet the requirements of Appendix W. [63]

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occur in the winter months. See Hoffnagle Report at 11, tbl. 2. EPA should have considered this point in its FIP Proposal, and did not.

[63] Interestingly, EPA has proposed that the BART Guidelines "no longer contain language that requires the use of CALPUFF or another Lagrangian puff model for long-range transport assessments." 80 FR 45340, 45349. In that proposed rulemaking, EPA

In its FIP Proposal, EPA did not use the "best" model (CALPUFF v. 6.42) or account for the flaws and limitations of the model it used. However, EPA claims to use the draft 2015 revisions to the CCM to reflect updated SCR cost analyses. See, e.g., 81 FR at 2032. It is arbitrary and capricious to use a draft, updated cost manual but not use an updated, proven visibility model.

2. *EPA's background ammonia concentration used in its CALPUFF modeling skews EPA's BART visibility improvement analyses* .Regional haze modeling – and the resulting predicted visibility improvement – is greatly influenced by the background ammonia number used in the model.[64] See Hoffnagle Report at 12. EPA improperly used a constant 1 ppb background ammonia number for its CALPUFF modeling for the Utah BART Units,[65] which greatly overestimated the "reasonably anticipated" visibility improvements from SCR. Id. EPA should have used available ammonia monitoring data in its modeling. EPA's failure to use this ammonia monitoring data "is unscientific and not supportable." Hoffnagle Report at 12.

In fact, instead of the constant 1 ppb ammonia number used by EPA, which Mr. Hoffnagle describes as "bad science" due to its failure to account for low winter ammonia levels, the "best" science requires the use of "variable ammonia" background numbers. Id. Given its geographic location and elevation levels, Utah undergoes seasonal swings of dry-hot summers (with higher ammonia levels) and snow-covered ground in the winter (with lower ammonia levels). Id. Therefore, the use of a single ammonia concentration for the entire year in a state where the land use and land cover changes significantly between seasons results in the overestimation of visibility improvements. (See e.g., July 2, 2010 letter and attachment from Tri-State Generation to Colorado Air Pollution Control Division, discussing Mt. Zirkel area,

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admits the "availability of more appropriate modeling techniques, such as photochemical transport models (which address limitations of models like CALPUFF)." Id. Yet, in its FIP Proposal, EPA failed to use a "more appropriate" model, such as a "photochemical transport model," or to even recognize the "limitations of models like CALPUFF." EPA's NOx BART determinations are invalid as a result.

[64] Sensitivity tests on ambient ammonia concentrations were performed by the Colorado Department of Public Health and Environment for an area in northwest Colorado. See Attachment 8. The analysis demonstrated that visibility calculations performed at Mount Zirkel Wilderness Area in northwest Colorado had limited impact when ambient ammonia concentrations were reduced from 100 to 1 ppb, but there was a significant reduction in visibility impacts when concentrations were further reduced to 0.1 ppb. Given the evidence presented above, the use of the monthly varying ammonia would provide much more accurate estimates of visibility impacts from the Utah BART Units. EPA's failure to use the "best science," variable background ammonia in its modeling, is arbitrary and capricious.

[65] EPA's refusal to use a "variable ammonia" number in its CALPUFF modeling for the FIP Proposal is very curious given EPA's "required use of monthly average relative humidity and hourly average ozone concentration data" in its model. See Hoffnagle Report at 12. The arguments EPA has used to justify a static, annual average for background ammonia apply with equal force to relative humidity and ozone. Id.

Attachment 8) "This means that exactly when nitrates are expected to form, in the colder months, there is much less (10-50% of the 1 ppb used in the modeling) ammonia available. . . . This wintertime deficit of ammonia is exactly why the EPA annual average ammonia background is bad science. It should be taken into consideration that the sulfur and nitrogen compete for the available ammonia, and in fact the sulfur wins especially during the summer." Hoffnagle Report at 12. EPA should have used the available background ammonia information, such as the information represented in the graphs on page 13 of the Hoffnagle Report, to run the CALPUFF model to determine the true impact of EPA's FIP Proposal.

Moreover, EPA has approved the use of variable gaseous ammonia concentrations in CALPUFF modeling before, including the Addendum to Modeling Protocol for the Proposed Desert Rock Generating Station (ENSR, 2006).

(http://www.epa.gov/region9/air/permit/desertrock/administrative.html). EPA Region 8 admitted the validity of using "variable ammonia" for CALPUFF modeling in its federal implementation plan for Montana, where EPA used "variable ammonia" in its CALPUFF modeling. 77 FR at 57867. ("As a result, we did not assume a constant level of ammonia as asserted by the commenter, and we did represent seasonal variability in ammonia concentrations. Additionally, EPA used the POSTUTIL program " with the Ammonia Limiting Method (ALM) to post-process the CALPUFF output to correct the assumption of constant ammonia availability in the model."). EPA also applied "variable ammonia" amounts when analyzing regional haze and BART issues in Wyoming. EPA Region 8 evaluated background ammonia concentrations for Wyoming in the updated CALPUFF modeling as a result of comments received on EPA Region 8's revised proposal published in June 2013. 79 FR at 5032, 5111. EPA admitted in Wyoming that an "accurate specification" of background ammonia is "critical to the accurate estimation of particulate nitrate concentrations." Id. at 5112. EPA also suggested that an "overestimate [of] the regional background concentration" would also result in the "overestimate [of] the visibility benefit due to NO[x] reductions." Id. at 5113. In fact, EPA claimed in Wyoming that the "*use of more realistic ammonia background concentrations*, the ammonia limiting correction, and the use of the 98th percentile modeled impact address the concern that the CALPUFF model could overestimate visibility impacts." Id. at 5,117.

Given EPA's recognition of the need to properly represent seasonally-variable background ammonia levels in CALPUFF modeling for sources in Wyoming, Montana, and Arizona, EPA should do the same here. In particular, where EPA relies on BART comparisons from power plants in Wyoming and Arizona to justify its FIP Proposal, EPA must ensure the CALPUFF visibility modeling (including the associated impacts of background ammonia) supporting EPA's FIP Proposal is similar to that done in Wyoming and Arizona. Moreover, EPA's failure to use seasonally-variable background ammonia levels in its CALPUFF modeling to support

its FIP Proposal skews the results of EPA's BART visibility improvement analyses. EPA's inconsistent actions in this regard are arbitrary and capricious.

3. *EPA applies the CALPUFF model to Class I areas that are beyond the model's geographic capabilities*. In its FIP Proposal, EPA indicates that it applied the CALPUFF model to 9 Class I areas, some of which are almost 300 kilometers or more distant from Utah's BART Sources. See e.g., 81 FR at 2035-36. EPA relied upon modeled "visibility improvements" in all nine Class I areas to justify its FIP Proposal. Id. at 2036-38. However, as explained above, CALPUFF has a large margin of error at 100 km and the inaccuracy likely grows at greater distances. The CALPUFF model "is not demonstrably valid beyond 100 kilometers and we can judge its margin of error at that distance but not beyond." See Hoffnagle Report at 12. As Mr. Hoffnagle explains, only three of the nine Class I areas addressed in EPA's FIP Proposal are within a distance where we can rely upon the results for gaseous concentrations to be within a range where we know the margin of error. Id. Therefore, EPA's FIP Proposal is invalid because it relies on CALPUFF modeled visibility improvements at Class I areas at distances up to 300 kilometer without making any adjustments or allowances for the impact of distance on these results, or by referring to monitored data to check the validity of the results.

4. *EPA made material, problematic changes in its modeling that prohibit comparisons with other modeling runs*. EPA also claims that, beyond "assessing impacts from individual BART sources and evaluating all technically feasible control options," its modeling was "otherwise very similar to that employed by Utah." 81 FR at 2033. Again, EPA is mistaken. EPA's CALPUFF modeling: (1) modeled different sources than Utah's modeling; and (2) used different assumptions about the amount of sulfate, nitrate, and particulate emissions. See Hoffnagle Report at 15-16.

a. *Modeling only individual BART Units resulted in erroneous modeling results and unsupportable BART visibility improvement analyses.* EPA admits that its CALPUFF model only included the "the impacts of the individual BART sources." See 81 FR at 2033. EPA also admits it determined a "source's" impact (two units at the same facility) by "summing the per unit improvements from Units 1 and 2" of Hunter. See e.g., 81 FR at 2037. This was a mistake. EPA should have modeled all four Utah BART Units together with SCR controls and two units at the same source (power plant) together with SCR controls. "When all the plants are run together the model would show a far smaller deciview impact than any additive result of running them separately. Each plume competes for the relatively small amount of ammonia assumed in the model. Once the ammonia is gone no more nitrate can be produced." See Hoffnagle Report at 15.

EPA claims in its FIP Proposal that a BART analysis must include "consideration of the visibility improvement from BART applied to the subject-to-BART source as a whole." See 81 FR at 2033. However, this is not how EPA conducted its CALPUFF modeling. EPA did not conduct CALPUFF modeling for the "subject-to-BART source as a whole," but rather conducted CALPUFF modeling

individually for each BART unit. EPA cannot simply "add" modeled visibility improvement numbers for each unit at a source to determine the source's impact; CALPUFF modeled results are not linear. Rather, the impact of the combined units' emissions must be considered by the CALPUFF model because of the atmospheric chemistry and the limiting factors (such as ammonia, etc.) on visibility impacts.

EPA also improperly excluded the reductions from the closure of the Carbon plant and reductions from Hunter Unit 3 when it conducted its CALPUFF modeling. "EPA's model runs never include the Carbon Plant and thus miss the reductions in nitrate and, more importantly, sulfate that occur because of those reductions." Hoffnagle Report at 15-16. Refusing to recognize Hunter Unit 3's installed emissions controls "skews the analysis in favor of more visibility improvement for the single unit SCR." Id. EPA's BART visibility analyses are invalid because the CALPUFF model runs did not include all Utah BART Units together, or as sources, or Carbon, or Hunter Unit 3, which skewed the results.

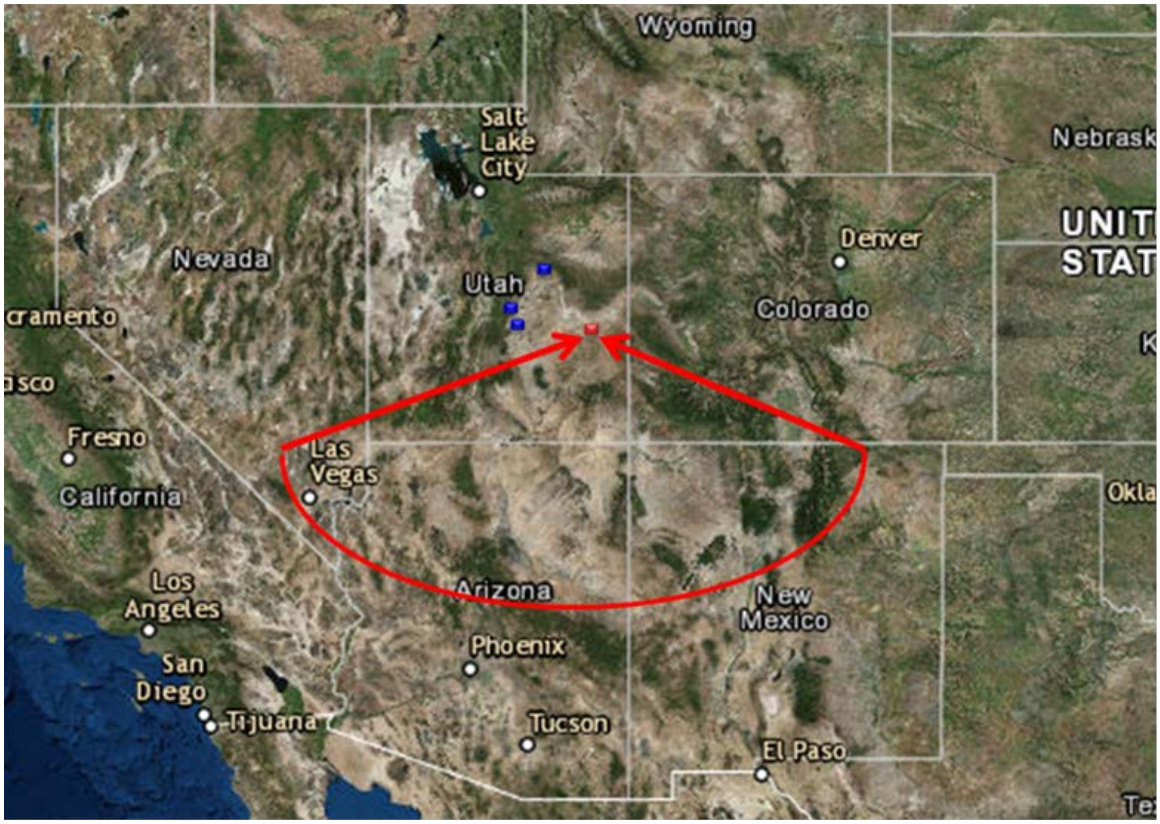
b. *EPA failed to include sulfate and particulate matter emissions from the Utah BART Units when modeling.* For some unknown and unsupportable reason, EPA reduces stack emissions of sulfate and particulate matter to almost zero in the EPA's CALPUFF modeling for the Utah BART Units. See Hoffnagle Report at 16. This modeling mistake "enhances the decrease in deciviews from EPA's model runs attributed to the use of SCR perhaps to a significant extent." Id. EPA also reduces sulfates, particulate matter, and nitrates emissions for Hunter Unit 3. These unexplained changes "are reason to call EPA's benefits from SCR into question." Id. EPA's BART visibility analyses are invalid as a result, as is EPA's FIP Proposal.

5. *When conducting its NOx BART determinations, EPA failed to consider the limited impact of further NOx reductions.* Finally, EPA's BART-related visibility analyses in the FIP Proposal are also flawed because they fail to account for the limited visibility impacts from NOx emissions in the relevant Class I areas. As EPA itself admits in the FIP Proposal, "anthropogenic visibility impairment on the Colorado Plateau is dominated by sulfates . . . sulfate is the largest contributor to visibility impairment at the affected Class 1 areas." See 81 FR at 2031. Additionally, EPA has found that "visibility benefits associated with NOx reductions are much more likely to occur in the winter months because this is when aerosol thermodynamics favor nitrate formation. By contrast SO2 emission reductions should provide visibility benefits in all seasons." Id. More importantly, as EPA is well aware, the State of Utah has determined based on its review of the data that "the visibility improvement during the winter months due to NOx reductions is much more uncertain." Id. EPA further admitted that the State of Utah had presented evidence that "while there has been a reduction in NOx, the ammonia nitrate values do not show similar improvement in the winter months." Id.

At a minimum, in its FIP Proposal EPA should have considered the fact that Utah had determined that NOx reductions did not seem to correlate to visibility improvement during the winter months, that sulfates are the largest contributors to visibility impairment, and that legitimate questions exist about whether or not further NOx reductions in the form of SCR at each Utah BART Unit would in fact improve actual visibility in the subject Class 1 areas. While EPA discussed these matters as part of the SIP Proposal, EPA inexplicably failed to consider these facts as part of its FIP Proposal. Such action was arbitrary and capricious.

Additionally, in its FIP Proposal, EPA also should have considered the relevant visibility data and information Utah provided to EPA in its Progress Report for Utah's State Implementation Plan for Regional Haze, dated September 23, 2014 ("Progress Report), Attachment 9. For example, as a result of the Progress Report, EPA is fully aware that Utah's "2008 BART determination has been fully implemented and significant reductions of NOx, SO2, and PM have already been achieved." Progress Report at 1. Additionally, the Progress Report explains that three Utah Class I areas show visibility improvement on the most impaired days, and for the two that do not show improvement, the "largest contributor to increases at these sites was particulate organic mass which was associated with large fire events." Id. at 3. The Progress Report also finds that generally "the largest contributors to aerosol extinction at Utah sites were particulate organic mass, ammonium sulfate and coarse mass." Id. at 13. The Progress Report contains other information indicating the relatively minor role NOx plays in visibility impairment in Utah's Class I areas, and the Progress Report identifies all of the categories of NOx emission sources (of which the Utah BART Units are but one part of one category). Id. at 25, tbl. 3.8. Unfortunately, EPA's FIP Proposal never discusses or considers the information from the Progress Report, including whether EPA can "reasonably anticipate" visibility improvement from EPA's NOx BART determinations (SCRs) given the impact from fires, the relatively small impact nitrates have on visibility, and the relatively minor contributions the Utah BART Units make towards the total NOx emissions that affect the Utah Class I areas. Without considering these issues, EPA cannot truly fulfill its statutory mandate to determine whether or not EPA can "reasonably anticipate" visibility improvement from its FIP Proposal.

6. *EPA Failed to Consider Wind Direction Data* – The following chart represents the wind direction for the 2001-2003 20% worst days when the nitrate contribution to haze was equal to or greater than 0.5 deciviews. See Attachment 10. The wind direction for these 20% worst days ranged from 115 degrees to 249 degrees. As can be seen, the prevailing winds do not come from the direction of the Utah BART Units. Therefore, EPA cannot "reasonably anticipate" visibility improvement on the 20% worst days resulting from the installation of the BART Benchmark at the Utah BART Units. This failure alone invalidates the FIP Proposal.



In short, EPA's visibility improvement analyses used to support its FIP Proposal are fatally flawed and cannot be used to support the NOx BART determinations.

V. EPA'S FIP PROPOSAL IS UNNECESSARY BECAUSE EPA ALREADY FOUND UTAH IS MAKING THE REQUIRED "REASONABLE PROGRESS."

States and EPA do not make BART determinations in a vacuum but within a framework carefully crafted to make "reasonable progress" towards the statute's national visibility goal. As part of that framework, Congress directed EPA to promulgate regulations "to assure . . . reasonable progress toward meeting" the national visibility goal, § 7491(b)(2), and mandated that EPA's regulations contain "such emission limits, schedules of compliance and other measures as may be necessary" to assure such progress towards meeting that goal, "*including*" a requirement that states make BART determinations. Id. (emphasis added). As EPA has stated, "BART is one component of long term strategies to make reasonable progress." Regional Haze Regulations and Guidelines, 70 FR at 39137.

Indeed, precisely because BART's purpose is to make reasonable progress, EPA adopted regulations exempting states from making BART determinations *at all* if they can show that other measures for large stationary sources, such as a cap- and-trade program, will achieve greater reasonable progress. 40 C.F.R. § 51.308(e)(2) (2012). EPA defended

those regulations in court by arguing that BART is one of a number of "emission limits, schedules of compliance and other measures" that "must" be included in a SIP "'as may be necessary to make reasonable progress toward national visibility goals.'" Ctr. for Energy and Econ. Dev. v. EPA, 398 F.3d 653, 659-60 (D.C. Cir. 2005) (confirming BART is but one measure for achieving "reasonable progress"); Cent. Arizona Water Conservation Dist. v. EPA, 990 F.2d 1531, 1534 (9th Cir. 1993) (same). According to EPA, if other measures better achieved those goals, then BART would not be "necessary to make reasonable progress." Id. The court agreed with EPA's analysis, although it overturned EPA on other grounds. Id. As the court said, "the focus of the Clean Air Act was to achieve 'actual progress and improvement in visibility,' 42 U.S.C. § 7492(b), not to anoint BART the mandatory vehicle of choice." Id. at 660.

Thus, EPA cannot validly judge a state's BART determination outside of its reasonable-progress context. Owasso Indep. Sch. Dist. No. I-011 v. Falvo, 534 U.S. 426, 434 (2002) ("'the words of a statute must be read in their context and with a view to their place in the overall statutory scheme.'"). As EPA recognizes, in some circumstances, no BART controls may be necessary to make reasonable progress. It follows that in other circumstances, depending on a state's reasonable- progress goals and expected non-BART emission reductions, BART controls of varying stringency may be necessary.

Here, EPA already has approved Utah's "reasonable progress" determination for its RH SIP in its entirety. See "Approval, Disapproval and Promulgation of State Implementation Plans; State of Utah; Regional Haze Rule Requirements for Mandatory Class I Areas Under 40 CFR 51.309," published at 77 FR 74355, 74367-68 (Dec. 14, 2012). EPA found that "the State met all reasonable progress requirements for the Class I areas," including by implication any required NOx BART limits. Id. In fact, EPA stated that Utah's 2008 RH SIP, including BART controls identified in that 2008 RH SIP, would result in "a significant decrease in stationary source NOx and SO2 emissions." Id. EPA further found that the NOx BART controls adopted by Utah for the Hunter and Huntington EGUs at issue would decrease NOx emissions by "6,200 tons [annually] between 2002 and 2018." Id. Therefore, EPA acknowledged that Utah's NOx BART limits and controls are all that are required to achieve "reasonable progress," and no further NOx BART requirements should be imposed by EPA through its FIP Proposal.

VI. Conclusion

For all of the reasons stated above, EPA should approve the Utah SIP as stated in the SIP Proposal, and should reject the FIP Proposal. What EPA cannot do, and indeed is not empowered under the CAA to require, is compliance with both the SIP Proposal and the FIP Proposal.

UTAH INVESTS $53 MILLION IN CALIFORNIA PORT FOR COAL, OTHER EXPORTS

Amy Joi O'Donoghue – Deseret News

Millions of tons of Utah coal will have a secure shipping port from a former Army base in Oakland, California, under a $275 million deal being brokered among multiple parties.

Four Utah counties — Sevier, Emery, Carbon and Sanpete — have already secured a $53 million low-interest loan from the state's Community Impact Fund Board to assure that Utah exports, notably coal, have a guaranteed share of the port's capacity.

The investment, approved earlier this month, buys Utah exports such as coal, potash, salt and hay cubes 49 percent of the new facility's capacity, described as 9 million metric tons. The dry bulk port will occupy land owned by Oakland City and provide a more direct West Coast route for the state.

Jeff Holt, a consultant for the counties, told the board members that port space is at a premium and other Western states are looking to secure viable shipping options as well. Wyoming lawmakers, he added, have agreed to spend $1 billion for access being eyed in the Pacific Northwest. In Utah's case, the money does not buy equity interest but rights of access.

Laura Nelson, director of the state Office of Energy Development, said the investment is a prudent use of money to ensure the state's coal supply has direct access to international markets.

"We have the resource here, and if we can move it to locations where we can displace low quality coal with our higher quality coal, that is a win-win for economic development and environmental improvements," she said.

Even as the U.S. demand for coal is ramping down and environmental regulations are bringing increasing pressure on domestic coal-fired power plants, Asian markets are hungry for the energy source.

"If you want to look at some of the fastest growing economies, they are in Asia," Nelson sad. "Indonesia, Thailand and Vietnam are in the top three in terms of per capita utilization of coal and they are doing that to enhance their quality of life and they are going to continue to do that so they can get affordable power to the masses." (…)

To read more, please visit the Deseret News.

The New York Times | http://nyti.ms/29aNbhL

U.S.

Oakland Votes to Block Large Shipments of Coal

By THOMAS FULLER JUNE 28, 2016

SAN FRANCISCO — The city of Oakland, Calif., on Monday banned the transport and storage of large coal shipments, a blow to a developer's plans to use a former Army base as an export terminal to ship coal to China and other overseas markets.

The terminal would have been the largest coal shipment facility on the West Coast, with a planned capacity to increase coal exports in the United States by 19 percent, according to the Sierra Club, the environmental group.

Weeks of feisty debate over the ban, which the Oakland City Council unanimously passed late Monday night and which will become law after a second reading next month, covered familiar ground: the trade-offs between jobs and environmental concerns.

But the debate also raised the larger and more unusual question of how much a city should weigh the global environmental impacts of the commodities that flow through its ports. A report prepared by the city argued for a coal ban partly because the coal, once it was burned overseas, would contribute to climate change and rising sea levels.

"Oakland cannot afford to ignore the scientific evidence that clearly show the

harmful effects and risk associated with coal," said Dan Kalb, a City Council member who proposed the ban along with the mayor, Libby Schaaf. "With this new law, we're taking the steps needed to protect our community, our workers and our planet."

The city's report calculated that exporting millions of tons of coal annually through the port of Oakland would release significantly more greenhouse gases than produced each year by all five oil refineries in the San Francisco Bay Area. And the report noted that Oakland was especially vulnerable to rising sea levels.

The ban is the second blow for the coal industry on the West Coast in recent weeks. In May, the United States Army Corps of Engineers denied a permit for a coal terminal planned 90 miles north of Seattle on the grounds that it would endanger wildlife.

The Oakland report, which was prepared by Claudia Cappio, an assistant city administrator, warned of the risks of cancer, heart and lung ailments and childhood developmental problems resulting from exposure to what it called "fugitive dust emissions" — the airborne particles generated from handling, transporting and loading coal onto ships.

The coal would have been shipped from Utah and other western states to the Oakland Bulk and Oversized Terminal, which is on an abandoned Army base across the bay from San Francisco.

The lead investor in the project, Phil Tagami, the chief executive and president of the California Capital and Investment Group, warned in an email of "legal consequences" from the decision.

"Exactly how much of the city's limited resources and how many jobs for West Oaklanders are this Council willing to sacrifice on this crusade?" he asked.

Mr. Tagami is one of the most prominent developers in Oakland and is a friend and political supporter of California's governor, Jerry Brown, a former mayor of the city.

A lawyer for Mr. Tagami, David Smith of the firm Stice & Block, wrote in a letter to the Council before the vote that a ban would be a "pronouncement to the world

that Oakland is not a trustworthy or reliable place to invest or do business."

Mr. Smith called the argument that coal exported from Oakland would increase the emissions of greenhouse gases "nonsensical and absurd" because power plants overseas would burn coal from somewhere else if they did not get coal from the Oakland port.

Mr. Smith also asked whether the concern over the global consequences of coal would apply to other goods that move through the city and its ports. "Under this approach, the city would have to hold gas station owners responsible for greenhouse gas emissions from cars that refuel at their facility," he said.

The vote comes at a time when Oakland is increasingly shifting toward technology jobs — and away from the city's blue-collar heritage. Pandora, the streaming music service, is based in Oakland, and Uber is moving its headquarters there next year.

Follow Thomas Fuller on Twitter @thomasfullerNYT.

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The Salt Lake Tribune
(http://www.sltrib.com)

Proponents buried coal's role in Oakland export terminal; now questions remain

By Brian Maffly The Salt Lake Tribune
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Updated: April 8, 2016 11:34AM

Utah's largest coal producer is an investor in the project but says it will diversify exports.

(Francisco Kjolseth | The Salt Lake Tribune) Coal trucked from central Utah piles up at the Levan transfer station south of Nephi, where it is loaded on Union Pacific freight cars bound for California. Utah's Community Impact Board has awarded a $53 million loan to four coal-producing counties to invest in a deep-water port in Oakland, Calif. hoping to connect central Utah commodities with export markets. Bowie Resource Partners already exports about 1 to 3 million tons of coal from its Utah mines.

As financier Jeffrey Holt urged Utah's Community Impact Fund to loan $53 million in public money to build an export shipping terminal in Oakland, Calif., he never said the word "coal" or mentioned Bowie Resource Partners.

Holt sought the loan at an April 2 meeting as an adviser to Sevier, Carbon, Emery and Sanpete counties — home to Bowie's Sufco, Dugout and Skyline mines. That same month, Bowie's chief commercial officer said the company did not have plans to use the proposed terminal.

"We have been advised the Oakland project is a multi-commodity terminal that will handle many different commodities such as potash, soda ash, and grain," Grant Quasha wrote to The Tribune in an April 22, 2015, email. "These facilities are 'purpose' built facilities and need to be tailored to types of commodities. That being the case it is not clear that it is commercially viable for our future needs."

But behind the scenes, Bowie and its Utah coal were at the center of the plan Holt was pitching to the counties.

Bowie would be "a Series A shareholder" in the terminal, according to a term sheet Holt provided to them in March 2015.

Terminal Logistics Solutions, the firm operating the terminal, "will be created as a part of the business arrangement between the Counties, Bowie, and any other users that can contracted ahead of time," it said.

Initially, up to 49 percent of the terminal's shipping capacity would be used to export coal — but that cap would only be an internal policy, not an official limit set in a permit.

“Presumably Bowie will get the throughput allocations to their mines in the Counties, at least for some number of years,” the term sheet notes.

The sheet and other documents were recently acquired by Sierra Club through open record requests to the four Utah counties. Sierra Club and Bay Area climate and environmental health activists have been challenging the export terminal project since the inclusion of coal became public.

“This wasn’t multi-commodity. This terminal is all about coal,” said Jessica Yarnall Loarie, a lawyer with Sierra Club’s Beyond Coal campaign. “Bowie went to great lengths to hide the ball from both Utah and California.”

On Friday, Bowie’s executive chairman John Siegel acknowledged his firm “has a vested interest in [Terminal Logistics Solutions] along with others and we are proud of that.”

Despite Quasha’s earlier assertion, Siegel said Bowie’s interest in the Oakland terminal stemmed from its ability to move a variety of products.

“We are called Bowie Resource Partners for a reason. While coal is our central commodity, we are looking to diversify the company across all commodities that make sense for us,” Siegel said. “That was central for our interest in the terminal.”

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Terminal questions • Last year, Siegel said, Bowie tried to acquire OCI Chemical Corp., a major soda ash producer that operates trona mines and processing plants in Wyoming. Soda ash, processed from trona, is a crucial ingredient in glass, detergents and other industrial products.

Bowie lost out to a Turkish firm. And now, the company is seeking to purchase three coal mines in Colorado and New Mexico from Peabody Energy, which is teetering on the brink of bankruptcy.

But Siegel said he will continue efforts to get into soda ash and other non-coal minerals.

“If and when it makes sense to export coal there [at the proposed terminal], we will do it,” Siegel said, ”but the focus shouldn’t be on coal because it will never be the predominant commodity run through the port at Oakland.”

Some Oakland city officials say they’re surprised that coal may be shipped through their community at all.

The export terminal would occupy 30 acres of a 330-acre redevelopment project at the former Oakland Army Base, located at the foot of the Bay Bridge. Known as Oakland Global Trade and Logistics Center, the larger project is under construction.

City officials say master developer Phil Tagami verbally promised coal had no part in his plans, and they signed a 2012 contract with Tagami’s firm that placed no restrictions on what commodities the port would move.

Terminal Logistics Solutions (TLS) incorporated in October 2014, according to California

Secretary of State documents. Its top executives are former Port of Oakland officials Jerry Bridges and Omar Benjamin. Benjamin resigned as the port's executive director in 2012 amid allegations that the port covered a tab he helped run up at a strip club.

In a July 2015 letter to Oakland's mayor after the proposal to ship coal had been revealed, Bridges said the terminal will be engineered to the highest environmental standards, with coal and other commodities delivered in newly designed covered rail cars and transferred in an enclosed system.

But the status of the proposed terminal is unclear.

The TLS lease option for the terminal site initially was set to expire in July 2015, according to the documents acquired by the Sierra Club. It was extended a few months to Oct. 17, but TLS has yet to exercise its option, according to the Los Angeles Times.

Bridges did not respond to repeated requests for comment. The TLS office is located in the same Oakland building as Tagami's firm, California Capital Investment Group. That company's publicist did not respond to an e-mail.

Besides Utah, no other investors in the $275 million terminal are known. BMO Capital Markets, which employs Holt as an investment banker, is seeking $200 million from private investors, and is marketing the opportunity to pension funds.

BMO also has a stake in the Central Utah Rail project — a proposed 48-mile line to connect Salina, near Bowie's Sufco mine, to the Union Pacific coal load out near Levan, which offers direct rail service to the Bay Area.

Without the Oakland terminal, the rail line will not be feasible, according to a memo Holt sent to the counties along with the term sheet.

"These two projects must be contractually linked in the negotiations," wrote Holt, a former member of Utah's Community Impact Board (CIB), the that group asked for the $53 million loan.

At the time he wrote the memo, Holt chaired the Utah Transportation Commission, which prioritizes projects for public funding. He had recently entered into a contract with Sevier County to secure financing for the rail project.

Once the $124 million rail line is operational, BMO will get a 2.5 percent "success fee," based on the value of the project — an additional $3 million incentive for BMO and Holt to ensure the Oakland terminal is funded.

Holt, who resigned his post on the transportation commission in December and moved to New York City, did not respond to an e-mail request for an interview.

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'There should be absolute openness' • Meanwhile, Gov. Gary Herbert last week signed a bill that clears the way for Utah's investment.

CIB approved the $53 million loan in April 2015, but it later discovered that transferring the

money — from federal mineral royalties — would require a new plan. Normally the funds are reserved for civic projects in the counties that produced the minerals. SB246 provided a way to work around funding restrictions.

Critics contend Utah's loan distorts markets by giving an unfair subsidy to a polluting energy source that the United States and many other countries are turning away from. Many suspect the terminal needs subsidies because private investors are wary of backing coal exports at a time of collapsing global demand.

Herbert's PAC landed half of Bowie's $29,000 in political contributions in Utah over the past two years, according to campaign finance disclosures. SB246 sponsor Sen. Stuart Adams, R-Layton, received $750 and similar donations went to numerous Republican lawmakers.

At his Thursday news conference, Herbert said he was unaware of Bowie's contribution, noting his PAC enjoys support from a variety of energy developers.

"That has nothing to do with the situation at hand. What we have is a group of rural counties — Emery, Carbon, Sevier, Sanpete counties — which have a significant economic concern about this war on coal," Herbert said.

"It's a very viable, legal, needed product in the world and we should have the right to export that product," he said. "And these counties have said, 'Hey, we have money involved, our [community impact] money, so let's pool that money and see if we can guarantee access to ship a legal product out of California.' Now we've set the money aside."

The Utah Attorney General's Office has previously remained silent about the deal, citing its client-attorney relationship with the CIB.

But Herbert assured reporters that his office will oversee the project and "there should be absolute openness and transparency at every step of the way."

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Defining the deal

If four coal-producing Utah counties invest $53 million in a California export terminal, Carbon County would hold the largest stake, according to documents acquired by Sierra Club through open-record requests.

Carbon County would hold 33 percent of Utah's interest, followed by Sevier at 30 percent, Emery at 25 percent and Sanpete at 12 percent.

For their investment, they would be guaranteed "throughput allocations" for their commodities equivalent to 49 percent of the terminal's capacity, the documents said.

Together, they would earn a 10 percent annual return, paid on a preferred basis from the

terminal's net income.

Utah officials defend the investment, saying it can connect rural Utah's products, including alfalfa, soda ash, potash and salt, to international markets.

But a term sheet indicates coal could monopolize Utah's share, consuming up to the full 49 percent of the terminal's shipping capacity.

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The New York Times

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Railroads, Utilities Clash Over Dust From Coal Trains

By JOSH VOORHEES of Greenwire

An effort by railroad companies to control dust blowing from coal trains has drawn the wrath of electric-power generators and the attention of federal regulators.

On its face, the dispute affects just more than 200 miles of track on two lines operated by BNSF Railway Co., but there are wide-ranging financial implications for the bottom lines of all U.S. railroad companies and the electric bills of ordinary Americans.

Three major rail carriers -- Union Pacific Corp., Norfolk Southern Corp. and CSX Corp. -- have filed paperwork to join the battle over coal dust. So have groups representing other shippers and power companies, including the American Public Power Association, which represents 2,000 or so community-owned utilities with more than 45 million Americans.

While the rail lines at the heart of the fight represent a fraction of the 233,000 miles of track in the United States, they rank with the most heavily traveled in the world and arguably the most important for U.S. energy production. The lines offer the only rail access to the Powder River Basin, a 20,000-square-mile region in Wyoming and Montana that produces 400 million tons of coal annually, almost 40 percent of the nation's total.

Two train derailments in May 2005 on the shorter of the two lines -- the Powder River Basin joint line -- left utilities short on coal, drove up energy prices nationwide and spurred warnings of possible brownouts.

Due to delayed coal deliveries and a lack of capacity after the derailments, Union Pacific -- which shares the joint line with BNSF -- stopped accepting new customers for Powder River Basin coal for nearly two years, from July 2005 to March 2007.

It was those derailments, BSNF said, that spurred its investigation of the effect of coal dust on railroad tracks.

After an extensive study, the company determined a dust buildup can prevent water from draining from track beds, which in turn can push steel rails out of gauge and cause derailments.

In order to prevent a repeat of 2005, the company told coal shippers last summer that it planned to limit coal dust leaving trains. BNSF left it up to the shippers, which own or lease the vast majority of the open-topped coal cars, to figure out how to meet the emission limit and how to pay for it.

'Double dip'

The dust limits were originally set to kick in last November, but BNSF delayed them until August after shippers asked the federal Surface Transportation Board to intervene. The railway, meanwhile, has welcomed a board review, believing its three-member panel will rule in its favor.

Power plants and shippers are opposing the coal dust cap for two main reasons. They say there is no proven link between coal dust buildup and the derailments. And even if such a link exists, they say, cleaning up the dust should be done by railways, which are responsible for track maintenance under their contracts with shippers.

By forcing the shippers to tackle the dust problem, the power companies maintain railroads are double-dipping, charging twice for the same service. Once, for the maintenance costs that are part of shipping contracts, and a second to limit dust emissions.

The Arkansas Electric Cooperative Co. (AECC), a utility that serves roughly 500,000 customers and has an ownership stake in three coal-fired coal plants, was the first to request federal intervention. The company did not return calls seeking comment, but in paperwork filed with federal regulators, its lawyers maintain BNSF is to blame for the track problems on the joint line.

"There are strong reasons to believe that substandard construction and failure by BNSF to perform proper routine track maintenance are the primary causes of the problems that BNSF blames on the coal dust, including the 2005 derailments," the filing states.

Mitigation costs

Coal dust emissions can be limited by several basic steps, such as by low-profile "bread loaf" loading -- where the top of the coal pile is rounded to produce less drag -- or by strategically positioning coal-carrying cars along the train to shield them from the wind.

Still, to achieve the limits BNSF is hoping to implement, coal shippers would likely need to take additional steps, such as covering loads with tarps or, more likely, spraying on a latex coating to keep dust from taking flight.

Regardless of the option chosen, emissions mitigation will come at a price.

Industry estimates the spray will cost 10 cents to 30 cents per ton of coal. The Arkansas cooperative said vendors have failed to provide specific quotes, but their own estimates put the cost to shippers "in excess of $100 million annually."

Furthermore, the cooperative argues that even if coal dust were to blame for track damage and regular maintenance won't solve the problem, BNSF's proposal for monitoring dust is arbitrary and unfair. Because trackside monitors would be placed in set locations, longer-traveling trains would shed a lot of dust before reaching a check point. Likewise, shorter trains with fewer coal cars would likely emit less dust than longer ones.

"The nature of the coal dust problem -- if there even is one -- has not been defined, and there is no assurance that shippers can, on their own, solve the problem to the satisfaction of BNSF's monitoring system," AECC's filing states.

BSNF officials declined to comment given the ongoing proceedings, but their filings argue that the "extremely high traffic levels" from the Powder River Basin pose "formidable operational challenges" that make the dust cap necessary.

The railroad's filing stresses that it has no provisions to enforce compliance or include penalties for a failure to meet dust limits. And the company decries "speculative" arguments that it could deny service to shippers that fail to meet the dust standard.

But there is little doubt that increased shipping costs would be passed on, at least partially, to the customers, leading utilities to complain that average Americans will get socked in the wallet.

"If shippers cannot satisfy BNSF's arbitrary emissions standard, and BNSF refuses to transport their coal from PRB, the generation of electric power for huge numbers of customers will be put at risk," AECC's filing states.

Coal shipping

The Powder River Basin consists of 18 coal mines, including Arch Coal's Black Thunder mine, the largest in the world. The 400 million tons mined annually are shipped to more than 30 states, the Powder River Basin Coal Users' Group said.

The vast majority of that coal must first travel a 103-mile joint line. According to a 2007 Congressional Research Service report, the line handles more than 60 loaded coal trains each day, with each stretching more than a mile.

Power plants buy coal from a number of mines and regions based on coal's price, energy content and transportation cost.

Powder River Basin coal is among the easiest and cheapest to mine. For the week ending Jan. 15, a short-ton of Powder River coal was selling at a sixth of the price of Central Appalachian coal, according to the U.S. Energy Information Administration. The low price is often enough to offset Powder River coal's relatively low energy content and high shipping prices.

Shipping rates for moving coal along the BNSF's joint line -- which is partially owned by Union Pacific but operated fully by BNSF -- has been a sensitive subject.

In 2007, North Dakota-based Basin Electric Power Cooperative complained to the Surface Transportation Board that BNSF was a monopoly and charged too much for service. The board ruled in favor of the railroad, saying the cooperative failed to prove rates were "unreasonably high."

Last February, however, the board sided with Basin Electric and the Western Fuels Association in a separate case and forced BSNF to slash rates on particular coal runs and reimburse an estimated $100 million to customers.

Buffett's bet

Berkshire Hathaway Inc., the investment firm headed by finance icon Warren Buffett, made headlines last year when it announced a $26 billion buyout of the remaining BNSF shares. Buffett hailed the move as an "all-in wager on the economic future of the United States," but the move was seen by some as a big bet on coal.

Even with recent dips in U.S. coal use, coal remains by far the cargo most hauled by rail. In 2009, railroads moved more than three times as much coal as they did chemicals, the second most-hauled commodity measured by freight car volume, according to the American Association of Railroads.

Major railways are capital-intensive businesses that are unionized and heavily regulated, adding to already-expensive operations. Up to half of BSNF's annual operating expenses go to short-term variables like labor, fuel and track maintenance, which is particularly cost-intensive along the heavily traveled joint line.

In 2006, BNSF and Union Pacific began work on a $100 million improvement to the Powder River Basin track. At the time, Matthew Rose, BNSF's chairman, president and CEO, said the project "underscores BNSF's commitment to this country's coal and power industries."

Still, in the same statement, Rose stressed that the burden should not be carried by the railroads alone. "The rail, mining and generating industries," Rose said, "all need to work together to keep coal a strong part of the nation's future energy program."

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Project could transform local coal market to international

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Coal from south central Utah may be on the cusp of finding a new, international customer base.

The Utah Permanent Community Impact Fund Board approved some $53 million in loan funding for a project that would allow four counties — Sevier, Sanpete, Carbon and Emery — to purchase an interest in a port that is under development in Oakland, Calif.

The funding was approved during a CIB meeting hosted in Salt Lake City Thursday in an 8-2 vote.

Concept for the future

Malcolm Nash, Sevier County economic development director, holds up a concept drawing Monday in Richfield of a port project in Oakland, Calif. Sevier, Sanpete, Carbon and Emery counties are exploring the possibility of purchasing an interest in the port for international shipping of locally mined coal.

“It’s all about finding a new home for Utah’s products — and in our neighborhood, that means coal,” said Malcolm Nash, Sevier County economic development director. He said the proposal has already received verbal nods of approval from Utah Gov. Gary Herbert and others.

“It is a different type of project,” Nash said. The proposal is for the CIB’s $50 million to be used to pay for a portion of the construction of a $250 million shipping port in Oakland. While CIB money would be used to fund the infrastructure, the four participating counties wouldn’t own the facility. Instead, they would own the right to use 49 percent of the port’s capacity for trans-Pacific shipping.

“The purchase of Sufco by Bowie [Resources] is what’s driving all of this,” Nash said. He said Bowie is interested in expanding its coal shipping capacity to international markets, which would make the coal industry in Utah viable over a longer period of time. Bowie is also affiliated with Trafigura, an international commodities shipping company with a focus on port infrastructure.

“There is a cliff,” Nash said. He said that by 2026 or 2027, the Intermountain Power Project near Delta is set to stop burning coal. This would be devastating to local mines if additional markets are not developed.

Coal from Sufco, located in Salina Canyon, is already shipped internationally, but on a limited basis. By purchasing a portion of the port’s capacity, the four partner counties would be able to use 49 percent of an estimated 750,000 tons of shipping capacity each year to ship coal and other products.

The project is still in a conceptual stage, and will take a lot of complex agreements in order to work, Nash said.

“Three million of that is for paying attorney fees and setting up the organization,” Nash said. Currently, plans call for the four partner counties to develop an infrastructure coalition, which would be an independent organization. The coalition would be in charge of the financial end of the project, and act as a shield to the involved counties to protect taxpayers’ interests, Nash said.

If the project comes to fruition, it could help keep Sufco and other coal mines in the state viable for decades to come, as well as provide an additional revenue stream to the partner counties.

The project could also be scrapped, similar to a proposed $3 billion rail line based in Uintah County. That project also relied on CIB funds, but was deemed financially unrealistic, so the funds were turned back to the CIB last year.

Those same funds are now being used for the port proposal.

Complementary projects

“We just kind of fell into it,” Nash said.

Nash said conversations with Bowie and members of the CIB about Sevier County’s ongoing rail project are what led to the proposal to buy into the Oakland port.

“The CFO of Bowie didn’t realize we had a rail project in the works,” Nash said. The county could have permits in hand for the rail project, 14 years in the making, later this year. When representatives of the CIB and Bowie found out about the possibility of a permitted rail project, it led them to discussions about the port, which has also been under development for years.

“We didn’t know what the other was doing,” Nash said. He said while the rail would be complementary to the port, the projects are not dependent on each other. The rail would also have a different partnership of counties — Sevier, Sanpete and Juab.

“With the rail, it comes down to there being enough freight to pay for it,” Nash said. “If there comes a time that rail is needed, it will be Bowie’s decision, not the county’s.”

The proposed rail line would run from Salina to the spike in Levan, cutting the distance coal needs to travel via truck by more than 40 miles. The idea is to reduce transportation costs for coal, but if the $110 million project doesn’t have enough freight on it to make it financially viable, it won’t happen.

Either way the rail project goes, the port project will likely happen — the only question is whether south central Utah will be a partner in it.

Port development

The proposed port would be located on a bow tie shaped piece of land in San Francisco Bay. Formerly occupied by an Army base, the land is owned by the city of Oakland. The company, Terminal Logistics Solutions, has signed a 66-year lease to develop the property into a port.

The port will cost approximately $250 million to build, which is where CIB’s funds would be invested.

“Normally, it doesn’t cost that much,” Nash said. He said Bowie’s representatives insisted that the facility be completely covered, to mitigate any concerns about coal dust, resulting in the hefty price. This means the railcars used to ship the coal would also have to be covered.

As of right now, the four partner counties’ role in the port is in a critical 90-day stage, where it is being reviewed by the Utah Attorney General’s Office as well as legal counsel hired by the partner counties, said Gary Mason, Sevier County commissioner. He said people who have experience in port development would scrutinize the economics of the project before anything is committed.

Racing to a deadline

The partner counties first found out about the port opportunity in February, but the clock is ticking on the project.

Bowie has an option on the port that expires in June. If everything works out, the partner counties will be able to use the CIB monies to help fund the project. Revenue generated by shipping through the port would be used to pay back the CIB loan.

“There is no general fund tax money involved in this project,” Mason said. He said protecting the county’s interest is the key concern.

“It’s open ended,” Mason said. “If there are other products [in the region] that could benefit from the port, they could also use it.” Mason said salt, potash and other commodities could be shipped through the port.

“This benefits the entire state,” Mason said. “First, we have to assess if we can prove to ourselves and everyone else that this is a viable project.”

If the project does not come to fruition, the CIB money would be turned back over for use on another project. If the project proves to be practical, it could be functioning and shipping Utah coal by summer 2017.