Docket:	:	A.13-12-013
Exhibit Number	:	
Reference No.	:	ORA-02
Commissioner	:	M.Florio
ALJ	:	D.Long/
	:	K.Bemesderfer
Witness	:	P.Sabino

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Prepared Testimony on Southern California Gas Company and San Diego Gas & Electric Company Application For Authority to Recover North-South Project Revenue Requirements in Customer Rates and Related Cost Allocation and Rate Design Proposals

REDACTED

Yellow Highlights on pages 10, 11, 12, 13, 14, 82, 83, and 85
Indicate confidential data redacted

San Francisco, California
May 8, 2015

TABLE OF CONTENTS

I. INTRODUCTION

This exhibit presents the analyses and recommendations of the Office of Ratepayer Advocates (ORA) regarding the Southern California Gas Company and San Diego Gas & Electric Company's (SoCalGas/SDG&E's or "Applicants" or Sempra utilities) updated proposal for authority to recover North-South Project (alternatively referred to as "NSP" or "Project") revenue requirements in customer rates, and for approval of related cost allocation and rate design proposals in Application (A.)13-12-013.[1] Sempra Energy is the parent holding company of both Applicants.[2] The Applicants assert that "[o]nly a physical upgrade that enables storage gas to reach the Southern System will provide Southern System customers with the same level of reliability received by customers located on the rest of the SoCalGas and SDG&E system."[3] Specifically, this exhibit examines the Applicants' claim that the NSP is "the best physical response to long-term Southern System reliability needs."[4]

This exhibit provides an economic comparison of the physical and non-physical (i.e., contract) alternatives available to SoCalGas/SDG&E in addressing long-term Southern System reliability needs. The reliable operations of SoCalGas Southern System is a responsibility of the utility's System Operator (S.O.). SoCalGas' Rule 41 states that "[t]he mission of the Utility System Operator is to maintain system reliability and integrity while minimizing costs at all times." The economic perspective in this exhibit is from one examining different alternative options to address the Southern System reliability needs and finding the most cost effective approach among those options.

---

[1] SoCalGas/SDG&E Application (A.) 13-12-013 originally filed and dated December 20, 2013, with updated project scope in November 12, 2014, p.1.

[2] Pursuant to the Commission's Merger Decision in D.98-03-073.

[3] Updated Testimony of Gwen Marelli for SoCalGas/SDG&E in A.13-12-013 dated Nov.12, 2014, p. 20.

[4] Id., p.25.

ORA also examines the Applicants' projects costs in greater detail and will show in this exhibit that, in terms of cost effectiveness, the Applicants' proposed Project is by far the least cost-effective physical solution to the Applicants' Southern System reliability needs compared to other physical alternatives available. More importantly, this exhibit demonstrates that there are a number of less expensive non-physical solutions (i.e., "no-build" alternatives) available to address the Applicants' Southern System long term reliability needs compared to the Applicants' proposed Project. These available non-physical solutions are also less expensive than each of the available proposed physical alternatives to the Project. The Commission has the obligation to make sure that utilities' rates are just and reasonable consistent with the safe and reliable delivery of gas transportation services.

The Applicants' updated Project proposal consists of installing 63 miles of new 36-inch pipeline between the town of Adelanto and its Moreno Pressure Limiting Station, and rebuilding the Adelanto Compressor Station with approximately 30,000 HP of compression.[5] The proposed Project will connect two existing backbone transmission facilities and thus the pipelines would be functionalized as backbone transmission.[6] The proposed Project has the capacity to transport 800 MMcfd of supply from the northern system to the southern system in the event of low deliveries at Blythe and/or Otay Mesa.[7] According to the Applicants, the reduced scope will substantially reduce the cost of the project by eliminating over $186 million in forecasted expenditures.[8] The reduced scope does not alter the 800 MMcfd capacity of the remaining components.[9] However, notwithstanding the elimination of $186 million of forecasted expenditures attributable to the Moreno-

---

[5] The original Application included only 60 miles for the Adelanto-Moreno pipeline segment and another 31 miles of new pipeline from Moreno to Whitewater but this latter component was deleted in the November 2014 update to the Application, where both Project scope and costs were revised. The Assigned Commissioner's Amended Scoping Memo and Ruling dated March 9, 2015, modified the scope of this proceeding accordingly.

[6] Response to SCGC DR15 Q.15.2.

[7] Updated Testimony of David Bisi for SoCalGas/SDG&E in A.13-12-013 dated Nov.12, 2014, pp.7-8.

[8] Updated Testimony of David Buczskowski for SoCalGas/SDG&E in A.13-12-013 dated Nov.12, 2014, p.1.

[9] Response to ORA-NSP-SCG-11 Q3(a).

Whitewater pipeline components, the remaining components of the proposed Project indicate overall increased costs of $178.8 million[10]. The Applicants' state that this component is permanently eliminated as part of the North-South Project, [11] but the pursuit of the Moreno-Whitewater pipeline component in a separate application remains a question.[12] In Answers to Questions in ALJ's Ruling in this proceeding, the Applicants state they have removed Moreno to Whitewater from the North-South Project, and this removal is permanent.[13] In addition, Applicants also state that the Moreno to Whitewater pipeline component is severable from the remaining proposed North-South Project.[14] ORA understands the foregoing statements to mean that the Moreno to Whitewater pipeline component is permanently removed as part of the North-South Project but nothing stops the Applicants from pursuit of the removed component later in a separate application given that it is severable from the remaining proposed North-South Project. The Commission should order the Applicants to categorically state the referenced statements mean permanent non-pursuit of the Moreno to Whitewater in any other application.

This exhibit will examine the Applicants' Project cost in greater detail. The increased cost of the remaining project scope is evident as the Applicants explain:[15]

> The Adelanto-to-Moreno pipeline route alignment adjustment resulted in an increase in mileage from approximately 60 miles to approximately 63 miles and increased footage in paved roads as opposed to previously planned dirt roads. The basis for valve spacing has also been refined resulting in an increase in mainline and other valves. These alignment and others changes increased the costs estimates for materials, engineering and construction…pipeline construction costs have increased over 5% in 2014 and going forward skilled pipeline construction trades are

[10] Compare Table 2, Updated Testimony of Buczskowski, p.5. and Table 1 Original Testimony of Buczskowski, p.1.

[11] Sempra Responses to the ALJ Questions in A.13-12-013 dated Feb.2, 2015, p.19.

[12] Updated Testimony of David Bisi for SoCalGas/SDG&E in A.13-12-013 dated Nov.12, 2014, p.11.

[13] SoCalGas and SDG&E Answers to Questions In ALJ's Ruling in A.13-12-013 dated February 2, 2015, p.18.

[14] SoCalGas and SDG&E Answers to Questions In ALJ's Ruling in A.13-12-013 dated February 2, 2015, p.15.

[15] Id., pp.2-4.

> commanding wage and per diem premiums as pipeline construction takes off across the country further driving costs. As a result of these and other construction challenges and risks, we have increased our construction cost contingencies to 16%...Estimated direct costs for the Adelanto Compressor Station upgrade have increased from $110.7 million to $136.8 million. The major drivers for the $26.1 million increase in the estimated direct cost of the Adelanto Compressor Station upgrade include: pipe and fittings, updated compressor equipment cost estimates; additional environmental costs; and an increase in Adelanto Compressor Station project contingency to 15%.

The Applicants' estimate of total Project direct costs amount to $622 million over the period 2014-2039 (in 2014 $).[16] On a fully loaded and escalated basis, the Project amounts to a total estimated cost of $855.5 million (in nominal $) over the same 2014-2039 period.[17] The Applicants assume that the Project is complete and placed into service by December 31, 2019 although certain components may be placed into service prior to this date.[18] Based on the estimated Project costs presented by the Applicants, the forecast revenue requirement on the first full year the Project is in service amounts to $133.6 million.[19] The total forecast revenue requirement is estimated to amount to $2.782 billion over the entire operating service life for SoCalGas to construct and operate and maintain its proposed Project (from 2018 to 2096).[20] The Commission should note that the amount requested for rate recovery by SoCalGas/SDG&E is not based on the estimated Project cost in this Application but on the actual costs that will be incurred to construct and operate and maintain the Project.[21] Thus, if adopted as proposed, ratepayers will not see what the ultimate cost of this Project means until the end of 2019 since actual Projects costs incurred will only be known later at project

[16] Table 3, Updated Testimony of Garry Yee for SoCalGas/SDG&E in A.13-12-013 dated Nov.12, 2014, p.3.

[17] Table 4, Id.

[18] Id., p.4.

[19] Table 5, Garry Yee, p.4.

[20] Table 5, Id., p. 4.

[21] Garry Yee, p.4

completion by the end of 2019. Compared to other alternatives, Sempra is in essence asking for a blank check. SoCalGas proposes to file an advice letter to incorporate the actual revenue requirement in rates.[22] The cost allocation and rate implications of the Applicants' proposal are also discussed in this exhibit. Although Applicants assert that the North-South Project is necessary,[23] the "best physical response," to long-term Southern System reliability needs, [24] and that "non-physical solutions will not solve the problem",[25] this exhibit shows that none of these assertions are true. In testimony and in a data response, the Applicants assert threats to Southern System supplies posed by the potential for increased gas volumes to flow to Mexico and the increase in electric generation demand on the Southern System.[26] This exhibit looks further into the Applicants' assertions regarding threats to Southern System reliability and options considered by SoCalGas/SDG&E before it reached the conclusion that the NSP is "the best physical response to the Southern System long-term reliability needs."[27]

ORA therefore respectfully recommends the Commission deny the Applicants' request for authority to recover the North-South Project revenue requirements in customer rates. Instead, the Commission should adopt a number of existing S.O. tools and measures which have been shown to be effective, or should modify them, and adopt new ones to provide the Applicants with a diversified portfolio of the most cost-effective tools and long-term solutions to the supply-related Southern System reliability. Alternatively, should the Commission find the need for a physical infrastructure solution to be necessary, then ORA recommends SoCalGas/SDG&E to first reassess the demand criteria used to determine the amount of capacity needed for the pipeline infrastructure and negotiate with the interested interstate pipeline company who offers the safest and

---

[22] Id.

[23] Marelli, p.1

[24] Marelli, p.25.

[25] Marelli, p.17.

[26] Response to ORA-SCG-02 Q.1(a).

[27] Marelli, p.21.

most reliable service at the lowest reasonable cost for the appropriate amount of capacity needed to address the SoCalGas Southern System supply-related reliability problem.

ORA provides a summary of its recommendations below.

II. SUMMARY OF RECOMMENDATIONS

ORA recommends that the Commission:

- Deny the Applicants' proposed North-South Project and find that the Applicants failed to demonstrate it is necessary to build this pipeline project in order to address the SoCalGas Southern System supply-related reliability issue.
- Find that the North-South Project is not the "best physical response," to long-term Southern System reliability needs;
- Find that Applicants' predictions of a gas supply shortfall stemming from intense competition for gas supplies are unwarranted;
- Find that the incremental rate from the North-South Project will not provide just and reasonable rates for the Backbone Transmission Service (BTS) and could possibly become stranded pipeline assets which ratepayers still have to pay for as discussed herein;
- Find that there are several less expensive non-physical alternatives available to address the Southern System supply-related reliability issues that will provide just and reasonable rates for the BTS;
- Adopt a broad range of non-physical "no-build" alternatives to address the SoCalGas Southern System minimum requirements and long term reliability before considering and authorizing any physical infrastructure alternatives in order to address supply-related reliability issues;
- Allocate the cost of the non-physical alternatives to manage the Southern System minimum flow requirements to the Backbone Transmission Service (BTS) and the BTS cost shared by all customers of SoCalGas as it is today;

Alternatively, should the Commission find that a physical infrastructure alternative is necessary in order to address the supply-related SoCalGas Southern System reliability issue, ORA recommends that the Commission:

- Order SoCalGas/SDG&E to first reassess the demand criteria used to determine the amount of capacity needed for the pipeline infrastructure and negotiate with the interested interstate pipeline company who offers the safest and most reliable service at the lowest reasonable cost; and

- Adopt an incremental ratemaking treatment for a physical infrastructure alternative where only those who has need for the physical project for reliability and sign up for the pipeline project should pay for it; and
- If SoCalGas/SDG&E's Project is adopted, place a cost cap.

Table 2-1 compares ORA's and SoCalGas/SDG&E's forecasts of annual revenue requirements over a 20-year period for the ORA recommended Non-Physical alternatives versus the proposed Project and the available proposed physical alternatives to the proposed Project. Table 2-1 indicates that on average over a 20-year period, the ORA recommended Non-Physical Alternatives [shown in columns (a) through (d)] will result in lower revenue requirements compared to the proposed Project [shown in column (e)] or the available proposed physical alternatives to the Project as shown in columns (f) through (h). The proposed Project's average annual revenue requirements over a 20-year period is substantially more than double those of ORA's recommended Non-Physical Alternatives. Take note that the calculation for the proposed Project are based only on forecast revenue requirements. These forecast numbers will likely be even higher when trued up based on actual costs at the end of the Project's completion. The proposed Project has no proposed cost cap.

Table 2-2 compares ORA's and SoCalGas/SDG&E's forecasts of illustrative average Backbone Transmission Service (BTS) rate impacts over a 20-year period based on the recommended ORA Non-Physical Alternatives versus the proposed Project and the proposed physical alternatives to the Project. Table 2-2 shows that on average over a 20 year period, ORA's recommended Non-Physical Alternatives [as shown in columns (a) through (d)] will result in much lower average BTS rates compared to the Project [shown in column(e)]or the available proposed physical alternatives [shown in columns(f) through (h)].

Table 2-3 compares the illustrative incremental BTS rate impacts of Physical and Non-Physical Alternatives for Year 1 of the Project in-service, with the ORA recommended Non-Physical Alternatives showing substantially lower expected incremental rate impact versus the proposed Project and the available proposed physical alternatives to the Project in Year 1 when the Project is in service. At Line 4 of Table 2-3, ORA shows the percent impact on current BTS SFV rates. At Line 4, the North-South Project in column (f) indicates an 81.3% impact on current BTS rates while the impact of the Non-Physical Alternatives range from 19.5% up to 33.4% depending on the amount of capacity assumed to be needed. The upper range of the impact of 33.4% is based on the same amount of capacity as the proposed Project. Three interstate pipeline companies who proposed physical alternatives to the Project indicate impacts from 44% up to no more than 60% based on the same amount of capacity as the proposed Project. Customers who make direct purchases of firm BTS capacity from SoCalGas such as the SoCalGas Gas Acquisition Department who performs the gas procurement function on behalf of bundled core customers, will be substantially impacted as shown in Table 2-3 at line 4 column (f). Since end-use customers do not normally make direct purchases of firm BTS capacity from SoCalGas, the impact of the incremental rates are not quite as significant as evident from Table 2-4.

Table 2-4 compares ORA's and SoCalGas/SDG&E's forecasts of illustrative Bundled rate impacts to end-use customer classes based on ORA's recommended Non-Physical Alternatives against the proposed North-South Project and the available proposed physical alternatives to the Project. At Line 6 of Table 2-4, the percentage impact on residential bundled rates of the non-physical and physical alternatives are shown. At Line 6, Non-physical alternatives would have an impact on the residential bundled rates ranging only from 0.3% to 0.4% while the North-South Project would have an impact of at least 1.1%. The other physical alternatives will impact residential bundled rates to the extent of 0.6% up to no more than 0.9%, which range would still be less than the Project's impact of 1.1%.

The interstate pipeline capacity cost charges could become part of the interstate charges included in the Core Procurement Rate. This is how all interstate reservation charges on behalf of core customers are treated, including charges associated with core capacity approved on recent expansion projects serving California such as the Ruby Pipeline.

The interstate pipeline costs can not be added to the BTS rate because the BTS rate represents intrastate transmission and are rolled-in to SoCalGas rate base. The BTS rate for SoCalGas can be likened to the PG&E Redwood/Baja Path rates, even taking into account that PG&E's are currently path-differentiated (PG&E requests a uniform "postage stamp" rate in its current pending GT&S proceeding, A.13-12-012, while SoCalGas' BTS is a postage stamp rate and not differentiated). ORA's analysis added the interstate pipeline costs to an equivalent in BTS rates solely for purposes of comparison to the Project, which SoCalGas requests rolling-in to its BTS rates.

Table 2-1
Illustrative Average Annual Revenue Requirements
Over 20 Years
(In Millions of Dollars)

Rely on Existing/Modified S.O. Tools 300 MMcfd (a)	Contract for Upstream Supplies 456 MMcfd (b)	Contract for Upstream Supplies 800 MMcfd (c)	Min. Flow Req for S.O. or End-Use 300 MMcfd (d)	Applicants' NSP 800 MMcfd (e)	TW 800 MMcfd (f)	EPNG 800 MMcfd (g)	TC** 800 MMcfd (h)
$38.9	$38.9	$66.8	$38.9	$91.7	$75.1	$72.30	$XX.XX

Note: **With compression

Table 2-2
Illustrative Average BTS Rate
Over 20 Years
(In $/dth/d)

Rely on Existing/Modified S.O. Tools 300 MMcfd (a)	Contract for Upstream Supplies 456 MMcfd (b)	Contract for Upstream Supplies 800 MMcfd (c)	Min. Flow Req for S.S. or End-Use 300 MMcfd (d)	Applicants' NSP 800 MMcfd (e)	TW 800 MMcfd (f)	EPNG 800 MMcfd (g)	TC** 800 MMcfd (h)
$0.036	$0.036	$0.063	$0.036	$0.086	$0.070	$0.068	$X.XXX

Note: ** With compression

Table 2-3
Illustrative Incremental BTS Rate
Year 1 Project In-Service
(in $/Dth/d)

Line No.	Item Description (a)	Rely on Existing/Modified S.O. Tools 300 MMcfd (b)	Contract for Upstream Supplies 456 MMcfd (c)	Contract for Upstream Supplies 800 MMcfd (d)	Min. Flow Req for S.S. or End-Use 300 MMcfd (e)	Applicants' NSP 800 MMcfd (f)	TW 800 MMcfd (g)	EPNG 800 MMcfd (h)	TC** 800 MMcfd (i)
1	Incremental BTS Rate	$0.030	$0.030	$0.052	$0.030	$0.125	$0.071	$0.068	$X.XXX
2	Current BTS SFV Rate	$0.154	$0.154	$0.154	$0.154	$0.154	$0.154	$0.154	$0.154
3	Total BTS SFV	$0.184	$0.184	$0.206	$0.184	$0.279	$0.225	$0.222	$X.XXX
4	Impact in %	19.5%	19.5%	33.4%	19.5%	81.3%	45.8%	44.0%	XX.X%

Note: **With compression

Table 2-4
Illustrative Bundled Rate Impacts to End-Use Customers
(In $/th)

	Item	Non-Physical Alternatives				Physical Alternatives			
Line No.	Description	Rely on Existing/Modified S.O. Tools	Contract for Upstream Supplies 456 MMcfd	Contract for Upstream Supplies 800 MMcfd	Min. Flow Req for S.S. or End-Use	Applicants' NSP	TW	EPNG	TC**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Incremental rate Impact	$0.003	$0.003	$0.005	$0.003	$0.013	$0.007	$0.007	
2	SCG Current Class Ave Rates								
3	Residential	$0.663	$0.663	$0.663	$0.663	$0.663	$0.663	$0.663	
4	Gas Commodity	$0.488	$0.488	$0.488	$0.488	$0.488	$0.488	$0.488	
5	Res Bundled Rate	$1.151	$1.151	$1.151	$1.151	$1.151	$1.151	$1.151	
6	% Impact on Res Bundled Rates	0.3%	0.3%	0.4%	0.3%	1.1%	0.6%	0.6%	
7	Core C & I	$0.306	$0.306	$0.306	$0.306	$0.306	$0.306	$0.306	
8	Core C & I Bundled Rate	$0.794	$0.794	$0.794	$0.794	$0.794	$0.794	$0.794	
9	% Impact on C&I Bundled Rates	0.4%	0.4%	0.6%	0.4%	1.6%	0.9%	0.9%	REDACTED
10	NGV	$0.106	$0.106	$0.106	$0.106	$0.106	$0.106	$0.106	
11	NGV Bundled Rate	$0.594	$0.594	$0.594	$0.594	$0.594	$0.594	$0.594	
12	% Impact on NGV Bundled Rates	0.5%	0.5%	0.9%	0.5%	2.1%	1.2%	1.1%	
13	NonCore C&I Dist	$0.067	$0.067	$0.067	$0.067	$0.067	$0.067	$0.067	
14	NonCore C&I Dist Bundled Rate	$0.555	$0.555	$0.555	$0.555	$0.555	$0.555	$0.555	
15	% Impact on NCCI Dist Bundled Rates	0.5%	0.5%	0.9%	0.5%	2.3%	1.3%	1.2%	
16	NonCore C&I TLS	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	
17	NonCore C&I TLS Bundled Rate	$0.502	$0.502	$0.502	$0.502	$0.502	$0.502	$0.502	

18	**% Impact on NCCI TLS Bundled Rates**	0.6%	0.6%	1.0%	0.6%	2.5%	1.4%	1.3%	
19	**EG Dist**	**$0.038**	**$0.038**	**$0.038**	**$0.038**	**$0.038**	**$0.038**	**$0.038**	
20	**EG Dist Bundled Rate**	**$0.526**	**$0.526**	**$0.526**	**$0.526**	**$0.526**	**$0.526**	**$0.526**	
21	**% Impact EG Dist Bundled Rates**	**0.6%**	**0.6%**	**1.0%**	**0.6%**	**2.4%**	**1.3%**	**1.3%**	
22	**EG TLS**	**$0.013**	**$0.013**	**$0.013**	**$0.013**	**$0.013**	**$0.013**	**$0.013**	
23	**EG TLS Bundled Rate**	**$0.501**	**$0.501**	**$0.501**	**$0.501**	**$0.501**	**$0.501**	**$0.501**	
24	**% Impact on EG TLS Bundled Rate**	**0.6%**	**0.6%**	**1.0%**	**0.6%**	**2.5%**	**1.4%**	**1.4%**	
25	**SDG&E Current Class Ave Rates**								
26	**Residential**	**$0.802**	**$0.802**	**$0.802**	**$0.802**	**$0.802**	**$0.802**	**$0.802**	
27	**Gas Commodity Price**	**$0.489**	**$0.489**	**$0.489**	**$0.489**	**$0.489**	**$0.489**	**$0.489**	**REDACTED**
28	**Res Bundled Rate**	**$1.291**	**$1.291**	**$1.291**	**$1.291**	**$1.291**	**$1.291**	**$1.291**	
29	**% Impact on Res Bundled Rates**	**0.2%**	**0.2%**	**0.4%**	**0.2%**	**1.0%**	**0.5%**	**0.5%**	
30	**Core C & I**	**$0.243**	**$0.243**	**$0.243**	**$0.243**	**$0.243**	**$0.243**	**$0.243**	
31	**Core C & I Bundled Rate**	**$0.732**	**$0.732**	**$0.732**	**$0.732**	**$0.732**	**$0.732**	**$0.732**	
32	**% Impact on C&I Bundled Rates**	**0.4%**	**0.4%**	**0.7%**	**0.4%**	**1.7%**	**1.0%**	**0.9%**	
33	**NGV**	**$0.121**	**$0.121**	**$0.121**	**$0.121**	**$0.121**	**$0.121**	**$0.121**	
34	**NGV Bundled Rate**	**$0.610**	**$0.610**	**$0.610**	**$0.610**	**$0.610**	**$0.610**	**$0.610**	
35	**% Impact on NGV Bundled Rates**	**0.5%**	**0.5%**	**0.8%**	**0.5%**	**2.1%**	**1.2%**	**1.1%**	
36	**NonCore C&I Dist**	**$0.063**	**$0.063**	**$0.063**	**$0.063**	**$0.063**	**$0.063**	**$0.063**	
37	**NonCore C&I Dist Bundled Rate**	**$0.552**	**$0.552**	**$0.552**	**$0.552**	**$0.552**	**$0.552**	**$0.552**	
38	**% Impact on NCCI Dist Bundled Rates**	**0.5%**	**0.5%**	**0.9%**	**0.5%**	**2.3%**	**1.3%**	**1.2%**	
39	**NonCore C&I TLS**	**$0.022**	**$0.022**	**$0.022**	**$0.022**	**$0.022**	**$0.022**	**$0.022**	

40	**NonCore C&I TLS Bundled Rate**	**$0.511**	**$0.511**	**$0.511**	**$0.511**	**$0.511**	**$0.511**	**$0.511**	
41	**% Impact on NCCI TLS Bundled Rates**	**0.6%**	**0.6%**	**1.0%**	**0.6%**	**2.5%**	**1.4%**	**1.3%**	
42	**EG Dist**	**$0.041**	**$0.041**	**$0.041**	**$0.041**	**$0.041**	**$0.041**	**$0.041**	
43	**EG Dist Bundled Rate**	**$0.530**	**$0.530**	**$0.530**	**$0.530**	**$0.530**	**$0.530**	**$0.530**	**REDACTED**
44	**% Impact EG Dist Bundled Rates**	**0.6%**	**0.6%**	**1.0%**	**0.6%**	**2.4%**	**1.3%**	**1.3%**	
45	**EG TLS**	**$0.013**	**$0.013**	**$0.013**	**$0.013**	**$0.013**	**$0.013**	**$0.013**	
46	**EG TLS Bundled Rate**	**$0.502**	**$0.502**	**$0.502**	**$0.502**	**$0.502**	**$0.502**	**$0.502**	
47	**% Impact on EG TLS Bundled Rate**	**0.6%**	**0.6%**	**1.0%**	**0.6%**	**2.5%**	**1.4%**	**1.3%**	

Note: **With compression

III. BACKGROUND ON PROJECT PROPOSAL

A. Applicants' Asserted Purpose of the Project

1. Applicants State The North-South Project is Necessary To Provide Flowing Supplies To Meet the System Minimums for the Southern System

The Applicants assert that the proposed North-South Project is necessary to provide flowing supplies to meet the system minimums for the Southern System.[28] The Applicants explain that minimum flowing supplies are needed each day on the SoCalGas Southern System and that without them, reliability would be compromised, and customers on the Southern System would face supply-based curtailments on a regular basis.[29] In a data response, Applicants explained that the reliability of a system is a function of both the physical infrastructure and the available flowing gas supply and both are necessary to provide reliable service.[30] Applicants confirm that "SoCalGas and SDG&E do have other parts of its combined gas transmission system that lack sufficient physical infrastructure to provide reliable service to our customers in the event of pipeline outages."[31] Applicants point out that the proposed "North-South Project is intended to address the other component that comprises reliability for the Southern System – a lack of gas supply – and in that regard, there are no other areas on the combined SoCalGas and SDG&E system that have this same reliability issue."[32]

Applicants also claim that physical supplies delivered to the Southern System are needed on a regular basis but only a portion of the system's needs can be served by flows from other portions of the system.[33] SoCalGas witness David Bisi

---

[28] Updated Testimony of Gwen Marelli in A.13-12-013 dated Nov.12, 2014, p.1.

[29] Marelli, p.1. Applicants state that they always strive to reduce potential for curtailments but have not quantified a risk reduction target in this case. See Response to ORA-SCG-02 Q.1(d).

[30] Response to ORA-NSP-SCG-06 Q1(a).

[31] Response to ORA-NSP-SCG-06 Q1(a).

[32] Response to ORA-NSP-SCG-06 Q1(a).

[33] Marelli, p.1.

describes the design configuration of the system that gives rise to the Southern System minimum flow requirements:[34]

> Unlike other parts of SoCalGas' system, the Southern System requires minimum flow volumes at the Blythe and/or Otay Mesa receipt points to maintain service to its customers in the Imperial Valley and San Diego load centers and other communities in San Bernardino and Riverside Counties. While supplies from the Chino and Prado Stations and from Line 6916 can flow eastward, these facilities provide only a limited amount of supplies to meet the demand of the Southern System during peak periods. Additionally, due to the telescoping operating pressures of the Southern System pipelines, the higher MinOPs of the pipelines east of Moreno Station restrict further eastward flow. Similarly, supplies delivered via Line 6916 cannot flow east of the Cabazon area. In other words, supplies delivered at the pipeline MAOP from Chino and Prado Stations and from Line 6916 are at lower pressures than the MinOPs on the eastern portion of the Southern Transmission System. As a result, the remaining supply needed to meet Southern System demand must be delivered from El Paso or North Baja at the Blythe receipt point, and/or from TGN at the Otay Mesa receipt point, in order to maintain service to both core and noncore customers on the Southern System.

The Applicants expect the Southern System minimum flow requirements will increase in the future.[35] However, Applicants state that they have not attempted to forecast future Southern System minimum flow requirements.[36] In the 2009 BCAP, however, SoCalGas discussed the Southern System minimum requirement as follows:[37]

> There is no algorithm or formula for the Southern System minimum flowing supply requirement. The minimum flowing supply for the Southern System is a function of the forecasted demand for the Southern System, including SDG&E demand, less the capability to provide additional supplies to the Southern System from the North Desert System or storage via the Chino and Prado crossovers. The Gas Control department estimates the level of demand and crossover capability each day.

[34] Bisi, p.7.

[35] Response to ORA-NSP-SCG-02 Q4(b).

[36] Response to ORA-NSP-SCG-02 Q4(b).

[37] Response by SoCalGas to Indicated Producers in DR#2 Q6.3 in 2009 BCAP A.08-02-001.

ORA understands that SoCalGas was able to transport 190 MMcf of gas to the Southern System via the Chino and Prado crossovers on Feb.2, 2011.[38]

The need for certain flowing supplies to meet the SoCalGas Southern System minimum flow volumes at Blythe and/or Otay Mesa receipt points is neither new nor unfamiliar to the Commission. Indeed, as described in detail below, the Commission addressed the need to provide minimum required flowing supplies in a variety of ways, including providing the SoCalGas S.O. with the tools deemed necessary to effectively perform the function and discharge its new responsibility. On August 26, 2003, SoCalGas filed Advice No. (AL) 3286 seeking authority to establish the Blythe Operational Flow Requirement Memorandum Account (BOFRMA) to record any charges SoCalGas' Gas Acquisition Department incurs to sustain operational flows at Blythe, which is a receipt point at the Southern System. Currently, gas supplies needed to meet the Southern System Minimum need to be delivered at El Paso Ehrenberg, North Baja Blythe or Otay Mesa.[39]

In AL 3286, SoCalGas explained that it must receive certain minimum quantities of gas at Blythe to ensure that adequate gas is available to maintain deliveries to customers connected to the southern portion of its system.[40] AL 3286 was approved by the Commission effective October 5, 2003. The BOFRMA was further extended in AL 3648 for a one year period, pending the Commission's consideration of SoCalGas' settlement agreement with Southern California Edison (SCE). The BOFRMA was established to track certain costs associated with the SoCalGas' Gas Acquisition Department's purchase and delivery of gas to sustain operational flows at Blythe. The costs recorded into the BOFRMA reflects only the incremental cost, relative to the SoCal bid-week border price, of purchases exceeding the Gas Acquisition Department's commitment of 355 MMcfd for deliveries at Blythe.[41]

---

[38] Response to SCGC DR4 Q.4.10.5.

[39] Response to ORA-NSP-SCG-02 Q4(d).

[40] SCG AL3286, p.1.

[41] SCG AL3286, p.2.

Subsequently, in D.07-12-019 which addressed the Applicants' settlement agreements with SCE to implement a range of revisions relating to the Applicants' natural gas operations and service offerings, the Commission authorized the transfer of the responsibility for maintaining the minimum flows at the SoCalGas Southern System to the utility's System Operator (S.O.) from the Gas Acquisition Department and authorized a number of proposed tools the S.O. can use for this purpose.[42] The SoCalGas departments responsible for the operation of its transmission system, including storage, hub services, pooling services receipt point access, offsystem deliveries, and system reliability, are broadly defined as constituting the SoCalGas System Operator.[43] The mission of the SoCalGas S.O. is "to maintain system reliability and integrity while minimizing costs at all times."[44]

Aside from spot gas purchase authority, D.07-12-019 allows the S.O. to query the marketplace through the issuance of Request For Offers (RFOs) to deliver a certain amount of gas for a set duration at a particular receipt point, or to stand ready to provide flowing gas at a particular receipt point when called upon by the System Operator. The Commission states:[45]

> The RFO will allow any respondent to present other services that could meet the needs defined in the RFO by the System Operator, such as use of interstate pipeline capacity. Within the RFO, the System Operator will define the quantity and duration of gas needed at a specific receipt point(s) but allow respondents to submit offers for all or only a portion of the quantity and other terms. The System Operator can thus select from a variety of suppliers, if necessary, to meet the flowing gas supply needs.

Also as part of the S.O. tools, the Commission gave SoCalGas the ability to request additional tools which may be deemed necessary for purposes of its new responsibility and allowed the use of a regular advice letter process, which process was subject to review in a forthcoming BCAP.[46] An example of the ability to ask for

---

[42] D.07-12-019, Ordering Paragraphs #15 and 16.

[43] D.07-12-019, p.58. See also SoCalGas Rule 41 regarding Utility System Operation.

[44] SoCalGas Rule 41.

[45] D.07-12-019, p.61.

[46] D.07-12-019, O.P.#17.

additional S.O. tool is shown by the SoCalGas request in advice AL 4353 and 4353-A which sought authority for the S.O. to move natural gas from Blythe to Otay Mesa, as needed, to maintain system reliability.[47]

The S.O. costs were authorized for tracking in a System Reliability Memo Account (SRMA) subject to review before passthrough to all customers.[48]

In subsequent advice letter filings, SoCalGas obtained authority to enter into agreements with its Gas Acquisition department referred to as Memorandum In Lieu of Contracts (MILCs) which address the provision of flowing supplies to meet the Southern System minimums.[49] In addition, pursuant to the third and latest MILC agreement, the Gas Acquisition department will continue to act on a "best-efforts" basis to provide the gas supplies based on the S.O.'s request if called upon as the provider of last resort pursuant to Section 12 of SoCalGas Rule 41.[50] Unlike the first two MILCs, the third MILC will last for three consecutive one-year terms, ending not later than October 31, 2016, unless cancelled by SoCalGas Gas Acquisition department or the S.O., or superseded by a Commission decision in this proceeding.[51]

In October 2014, SoCalGas also received approval of AL 4517, which would allow discounted firm Backbone Transmission Service (G-BTS) contracts without alternate receipt point rights. This proposed change would provide the SoCalGas

[47] AL 4353 and 4353-A were approved effective July 12, 2012 in a letter to SoCalGas by Energy Division.

[48] D.07-12-019, OP#17.

[49] SoCalGas AL 4291 for MILC1 approved with modifications in Resolution G-3468; AL 4394 for MILC2 approved with modifications in Resolution G-3476, and AL 4513-A for MILC3 approved with modifications in Resolution G-3485.

[50] Revised Third MILC in AL 4513-A, p.2. In Rule 41, the provider of last resort relates to the circumstance when all the available tools have been exhausted by the S.O. and the S.O. has been unsuccessful to obtain the required minimum volumes to meet the required supplies at specific locations and that places system reliability in jeopardy.

[51] Revised Third MILC, p.1.

System Operator with another potential tool to help it maintain minimum flows on the SoCalGas Southern System.[52]

To the extent that Commission granted authority for RFOs and the ability to ask for additional tools, in addition to spot market purchase authority, the Commission in D.07-12-019 effectively allowed the SoCalGas S.O. some degree of flexibility. The S.O. can determine additional tools deemed necessary to perform its function to meet the system minimums for the Southern System. This also confirms the usefulness of an approach that provides a broad range of S.O. tools to guard against the risk of curtailments, which could result if the S.O. were to rely solely on spot market purchases. That is, if the need for additional supply was realized too late and SoCalGas is trying to secure large quantities of gas in the spot market, especially in later nomination cycles, the SoCalGas S.O. could be faced with much higher costs for those incremental supplies to the Southern System.

As shown above, since at least 2003 when the BOFRMA was first established, the need to provide flowing supplies to meet the system minimums for the SoCalGas Southern System was a matter already previously known to, and addressed by the Commission.

SoCalGas requests approval of the proposed North-South in order to provide for long term reliability to the Applicants' Southern System customers, notwithstanding all the S.O. tools already authorized thus far. The Applicants seek to persuade the Commission that the North-South Project is necessary to address the reliability problem due to a lack of supply in the Southern System[53], that non-physical solutions will not solve the problem,[54] and that the North-South Project is the best physical solution.[55] The Applicants' arguments in support of the Project's necessity are described below.

---

[52] AL 4517, p.1.

[53] Response to ORA-NSP-SCG-06 Q1(a).

[54] Marelli, p.17.

[55] Marelli, pp.21-25.

2. Applicants Assert that a Trend of Rising Southern System Support Costs Is Expected To Continue

SoCalGas states that Southern System support costs have been rising during the past few years and expects to continue on this path of rising costs.[56] Table 1 presented in Ms. Marelli's testimony shows the costs of Southern System support after transfer to the S.O, beginning in September 2009 and continuing through August 2013.[57] The purchases (in Mdth) presented in Table 1 show significant variations from the first 12-month period to the next 12-month period and so on. SoCalGas explains the reason for the yearly variations in Figure 1 of Ms. Marelli's testimony.[58] According to SoCalGas, Figure 1 shows that average customer deliveries were falling over the same period that the Southern System minimum was increasing.[59] SoCalGas explains in response to ORA's data request on that topic:[60]

> Customer purchases were falling at the same time that the Southern System minimum was increasing. As a result the frequency and the size of the gap between customer purchases and the minimum increased over the period, which translates into System Operator purchases.

A note with an asterisk below Table 1 states that "96% of these supplies were baseload winter supplies approved in G.3435."

The Southern System support costs shown in Table 1 of Ms. Marelli's testimony are consistent with the amounts in SoCalGas Annual Compliance Reports submitted via advice letter filings pursuant to D.09-11-006. The trend in the first 48 months shown in Table 1 is one of rising Southern System support costs incurred by the S.O. and the Applicants expect this rising trend to continue stemming from predictions of intense competition for gas supplies as later explained here.

ORA notes that the SRMA costs in Table 1 shows a huge increase in the fourth year (about 3.5 times) compared to the first 3 years. When asked about this,

[56] Marelli, p.5.

[57] Table 1, Marelli, p.4.

[58] Figure 1, Marelli, p.5.

[59] Response to ORA-NSP-SCG-02 Q5(a).

[60] Id.

the Applicants explain that the purchases requested by the S.O. almost tripled in the final year compared to the previous years and that the net cost of those purchases increased in the fourth year.[61]

The amounts of the Interruptible Transmission Backbone Transmission Service (IT BTS) Ehrenberg discounts in Table 1 also noticeably showed a dramatic increase in the fourth year to $12.1 million compared to zero $ amounts in the first two years. SoCalGas explains that the utility did not use the BTS discount strategy until December 2011 and that the fourth year is the only one in which the utility discounted its BTS at Ehrenberg throughout the year.[62]

The total costs in the final column of Table 1 shows rising total amounts each year from $2.2 million in the first 12-month period and to $3.8 million in the second 12-month period. The dramatic increase in total costs starts in the third 12-month period with $9.1 million through the fourth 12-month period with $20 million in total costs.

ORA's review revealed that the BTS discounts were behind the dramatic increases in total costs noted.

In particular, ORA reviewed AL 4406 Attachment B for the costs incurred from September 1, 2011 through August 31, 2012 to maintain the Southern System reliability. The costs reported in this AL covers the third 12-month period where the dramatic increase in total costs as observed in Table 1 of Ms. Marelli's testimony began. According to AL 4406, SoCalGas spent a total of $2,191,549 to meet the Southern System minimum flow requirements. The utility reported that over fifty-one days, SoCalGas purchased 6,612,893 dths of spot gas at Ehrenberg for $22,449,505 which was almost six times as much spot gas volumes as had been purchased in prior annual filing periods. This spot gas was then resold at the SoCal Citygate for $20,593,901, which means a net cost of $1,855,604. In addition to this net purchase cost, there were the applicable $242,926 of Backbone Transmission Service (BTS) charges. Also, the Gas Acquisition transported 225,000 dths to Otay

[61] Response to ORA-NSP-SCG-02 Q5(b).

[62] Response to ORA-NSP-SCG-02 Q5(c).

Mesa in February per the System Operator's request, which amounts to an incremental transportation cost of $93,019. Altogether, the total SRMA recorded costs amount to $2.2 million. But it is the BTS discounts at Ehrenberg that raised the cost by an additional $6.9 million, to bring the total costs for that period to $9.1 million.

The story is the same with respect to the fourth 12-month period showing the increase in total costs of $20 million in Table 1 of Ms. Marelli's testimony. ORA reviewed SCG AL 4547 Attachment B, for the period from September 1, 2012 through August 31, 2013. SoCalGas spent $7,876,555 to meet the Southern System minimum flow requirements. Attachment B shows that over 98 days, SoCalGas purchased 19,319,690 dths (net of in-kind fuel) of spot gas at Ehrenberg for $76,999,571. This spot gas was then resold at the SoCal Citygate for $70,356,785, which means a net cost of $6,642,786. In addition to this net purchase cost, there were $1,233,768 of applicable BTS transportation charges. Altogether, the total SRMA cost is reported to be in the amount of $7,876,555. The amount of $7.9 million is more than three times higher than the $2,191,549 requested in AL 4406 in the previous 12-month period. Costs were driven higher by the total volumes purchased to support the Southern System, which are almost three times higher than volumes purchased in the prior year covered by AL 4406. ORA notes once again that it is the amount of BTS discounts at Ehrenberg that raised the cost by an additional $12.1 million to bring the total costs for that period to $20 million.

Use of both firm and interruptible BTS discounts are authorized in SoCalGas' Schedule BTS.[63] The Commission acknowledges the effectiveness of these additional S.O. tools in managing Southern System reliability.[64] SoCalGas made a slight revision to the firm BTS discount so that it offers the right incentive to flow gas into the Southern System for purposes of reliability. In the SoCalGas Post-Forum 2014 Report submitted in AL 4666, SoCalGas describes its efforts to make a slight modification to the way it could offer the firm BTS discounts without alternate receipt

[63] Findings and Conclusions 4 & 5, Resolution G-3488 approves AL 4517 and 4517-A.

[64] Parag#1, Discussion Section, Resolution G-3488.

point rights in (then pending) AL 4517. The change would allow offering discounted firm BTS service without alternate receipt point rights so that could only be used to transport gas from the SoCalGas Southern Transmission Zone.[65]

The Applicants' expectation of continued rising system support costs does not appear to have any specific analytical support behind the forecast. When asked whether SoCalGas conducted any analysis of the likely range of the system support costs for the period 2014 through 2019, Applicants simply answered no.[66]

3. Applicants Assert Increased Threats To Southern System Reliability

SoCalGas witness Marelli argues that there are increased threats to Southern System reliability, and those stem from the expectation of increased gas supplies exports to Mexico and the expectation of continued robustness in the Southern System electric generation demand since the closure of the San Onofre Nuclear Generating Station (SONGS).[67] Thus the trend of rising Southern System support costs shown in Table 1 of Ms. Marelli's testimony is expected to continue based on these perceived threats to Southern System reliability. It is based on the Applicants' belief that "customer deliveries to the Southern System will continue to drop as supplies transported on El Paso's South Mainline are diverted to the anticipated higher-value Mexican markets."[68] SoCalGas uses the term "higher-value" to refer to price premiums generally paid by the Mexican government for its gas purchases through Pemex.[69] SoCalGas expects that the net cost of Southern System support purchases will increase as the competition for gas supplies increase.[70] Applicants attribute the minimal volume of supplies received into the Southern System at Otay

[65] Attachment A, SoCalGas AL 4666, p.4.

[66] Response to Transwestern DR1 Q.3(a).

[67] Marelli, p.6.

[68] Marelli citing the discussion by Mr.Chaudry (another SoCalGas witness), p.5.

[69] Response to ORA-NSP-SCG-02 Q.8(a). Footnote 1 in the Response: Pemex is Mexico's state oil and gas monopoly and controls exploration, processing and sales.

[70] Marelli, p.6.

Mesa to market conditions in Mexico and the United States. [71] These market conditions include both the growing demand for natural gas in Mexico and increased exports to Mexico.[72]

In addition, SoCalGas states that "Since the closure of the San Onofre Nuclear Generating Station (SONGS), demand by Southern System electric generators has increased by approximately 80-100 MMcfd, as demonstrated in Figure 2 below."[73] According to the Applicants, electric generation demand on their systems have been strong since the SONGS outage began in early 2012 (i.e.,January 2012), and point to potential gas-fired generation projects proposed in their service territories as placing additional supply-related strains on the Southern System.[74]

ORA's discussion of the alleged threats of US gas exports to Mexico, the increasing gas demand from Mexico and the alleged threat from robust EG demand is provided in Section IV A of this exhibit.

B. Applicants' Description of the Updated Project Components

Applicants' state that the proposed North-South Project consists of two major components: the Adelanto to Moreno Pipeline and the Adelanto Compressor Station.[75]

Further, Applicants also state that SoCalGas will no longer be moving forward with the proposed 31-mile Moreno-to-Whitewater pipeline portion of the Project.[76]

Each component provided by the Applicants is described in more detail below.

---

[71] Response to ORA-NSP-SCG-02 Q2(d).

[72] Response to ORA-NSP-SCG-02 Q2(d).

[73] Marelli, p.6.

[74] Marelli, p.7.

[75] Updated Testimony of David Buczkowski in A.13-12-013 dated Nov.12, 2014, pp.5-17.

[76] Buczskowski, p.1.

1. Applicants' Proposed Adelanto – Moreno Pipeline

The Adelanto-Moreno pipeline is proposed as a new 36-inch diameter pipeline.[77] The pipeline route adjustments result in an increase in mileage from approximately 60 miles to approximately 63 miles.[78]

The Applicants' detailed technical description of the Adelanto-Moreno pipeline is provided in the testimony of Mr. Buczskowski:[79]

2. Applicants' Proposed Adelanto Compressor Station

The Applicants propose to rebuild the existing Adelanto Compressor Station with approximately 30,000 HP of compression.[80]

The Applicants' detailed technical description of the Adelanto-Moreno pipeline is provided in the testimony of Mr. Buczskowski:[81]

C. Applicants' Description of Estimated Updated Project Costs and Revenue Requirements[82]

1. Applicants' Estimated Direct Project Costs

The Applicants' estimate total Project direct costs to be $622 million over the period 2014-2039 (in 2014 $) as presented in Table 3 of Mr. Yee's testimony.[83] Capital costs amount to a total of $621.3 million while Operating and Maintenance (O&M) cost amount to a total of $0.7 million. According to the Applicants, these capital and O & M costs represent only the direct costs stated in base year 2014 dollars and do not include overhead, escalation, or other necessary costs to support the investment.[84] Table 1 of Mr. Yee's testimony show the Project overhead loaders

[77] Buczskowski, p.1.

[78] Buczskowski, pp.1-2.

[79] Buczskowski, pp.2-5.

[80] Buczskowski, p.1.

[81] Buczkowski, pp.6-9.

[82] Appendix A, Buczkowski Testimony, pp.22-28 and Tables 1 – 5, Updated Testimony of Garry Yee in A.13-12-013, pp.2-4.

[83] Table 3, Updated Testimony of Garry Yee for SoCalGas/SDG&E in A.13-12-013 dated Nov.12, 2014, p.3.

[84] Garry Yee, p.1.

applied in the Applicants' analysis.[85] The Applicants explain the use of illustrative overhead rates which were estimated using 2013 actuals and state that these overhead rates are only illustrative for forecasting purposes.[86] The Commission should note that Applicants propose to use actual overhead rates for each year in the calculation of the actual revenue requirement. Applicants represent that only overheads that are incremental to the North-South Project are included.[87] As an example, the Applicants state that Pension and Post-Retirement Benefits Other Than Pensions overhead costs are excluded. The proposed Project escalation rates by each cost type are provided in Table 2 of Mr. Yee's testimony.[88] According to the Applicants, the forecasted capital costs do not include the cost of removal associated with the existing Adelanto Compressor Station since these are already accounted for in authorized depreciation rates.[89] If adopted as proposed, the Commission should be able to verify these representations regarding the derivation of actual costs.

2. Applicants' Estimated Fully Loaded and Escalated Project Costs

On a fully loaded and escalated basis, the direct costs of the Project from Table 3 of Mr. Yee's testimony amounts to a total estimated cost of $855.5 million (in nominal $) over the same 2014-2039 period.[90] These are presented in Table 4 of Mr. Yee's testimony. The capital costs amount to $854.8 million while the O&M costs amount to $0.7 million.

3. Applicants' Estimated Forecast Revenue Requirements

Based on the estimated Project costs presented by the Applicants, the forecast revenue requirement on the first full year the Project is in service amounts to $133.6 million.[91] The total forecast revenue requirement is estimated to amount

---

[85] Table 1, Garry Yee, p.2.

[86] Garry Yee, pp.1-2.

[87] Garry Yee, pp.1-2.

[88] Table 2, Garry Yee, p.2.

[89] Garry Yee, p.3.

[90] Table 4, Id.

[91] Table 5, Garry Yee, p.4.

to $2.782 billion over the entire operating service life for SoCalGas to construct and operate and maintain its proposed Project (from 2018 to 2096).[92] Applicants state this revenue requirement captures all capital-related costs such as depreciation, taxes and return needed to support the investment.[93]

D. Description of Applicants' Proposed Cost Allocation and Rate Recovery and Rate Impacts

1. Proposed Cost Allocation to Backbone Transmission Service

The Applicants propose to allocate the actual gas transportation revenue requirements associated with the Project to its Backbone Transportation Service (BTS) rates.[94] The Applicants BTS rates are said to be similar to postage-stamp rates where customers pay a common rate to deliver gas along the backbone transmission system from any receipt point to the SoCalGas Citygate.[95] To avoid incurring BTS rates, customers can also buy gas at the SoCalGas Citygate, where gas can be bought without purchasing backbone capacity.[96] From the Citygate, customers may then deliver gas to their end-use account at the appropriate "Citygate-to-meter" transportation rate.[97] The BTS is available on both a firm and an interruptible basis.[98] Similar to interstate rates, the BTS firm service is available either on a Straight Fixed Variable (100% reservation) or a Modified Fixed Variable charge (i.e., part reservation, part volumetric) while Interruptible BTS are 100% volumetric.[99]

2. Proposed Recovery of Actual Costs in Rates

The Applicants' proposed BTS revenues and rate impacts are shown in Table 1 of Mr. Bonnett's testimony.[100] The BTS revenues and rates shown in Table 1 are

[92] Table 5, Id., p. 4.

[93] Garry Yee, p.4.

[94] Jason Bonnett Updated Testimony in A.13-12-013, p.1.

[95] Bonnett, p.1

[96] Bonnett, p.1

[97] Bonnett, p.1.

[98] Bonnett, p.1

[99] Bonnett, p.1

[100] Bonnett, p.2

only illustrative and are calculated based on forecast revenue requirements. The Applicants propose that upon project completion, SoCalGas will compute the actual capital and O&M costs and associated revenue requirement.[101] The Applicants propose that SoCalGas file an advice letter within 60 days after the assets are placed into service to incorporate the actual revenue requirement in rates on the first day of the next month following advice letter approval.[102] The revenue requirement in rates will be updated in subsequent years in connection with SoCalGas' Consolidated Rate Filing for rates effective January 1st of the following year.[103] Applicants propose that this process continue until addressed in SoCalGas' next General Rate Case or other applicable proceeding.[104]

Table 1 of Mr. Bonnett's testimony shows the illustrative rate impacts at the backbone transmission rate level. In the first full year of the Project's operation, Column D in Table 1 of Mr. Bonnett's testimony shows the current BTS SFV rates to be $0.154 per dth/d in the year 2020. Next in column E of Table 1, the BTS rate impact of the NSP is $0.125 per dth/d. Column F combines the current BTS rate in column D and the BTS rate impact of the NSP in column E, which together amounts to $0.279 per dth/d in the year 2020. The estimated BTS rate of the NSP is $0.125 per dth/d which represents an 81 percent increase from the current BTS rate of $0.154 per dth/d. Core bundled customers pay for the BTS rate in their gas procurement rate through the purchases made by the SoCalGas Gas Acquisition department, which procures the gas supplies for the Core bundled customers.

Table 2 of Mr. Bonnett's testimony shows the illustrative bundled rate impacts of the Project at the end-use level. Table 2 shows residential customers could pay an additional $0.013 per therm attributable to the NSP, which translates to an additional $0.488 per month to residential bills based on an average use of 39 therms per month. This represents a 1.1 percent projected increase in the average

[101] Garry Yee, p.4.

[102] Garry Yee, p.4.

[103] Garry Yee, p.4.

[104] Garry Yee, p.4

residential monthly bill. These rate impacts are only illustrative. The actual rate impacts could be different and likely higher by the time project completion is achieved and is in service.

IV. GENERAL OVERVIEW AND DESCRIPTION OF ALTERNATIVES TO THE PROJECT

In testimony and in a data response, the Applicants assert threats to Southern System supplies posed by the potential for increased gas volumes to flow to Mexico and the increase in electric generation demand on the Southern System.[105] This section looks further into the Applicants assertions regarding threats to Southern System reliability and options considered by SoCalGas/SDG&E before it reached the conclusion that the NSP is "the best physical response to the Southern System long-term reliability needs."[106] In addition, the other options for consideration by the Commission and the Applicants are laid out here.

A. Applicants' Alleged Threats to Southern System Reliability Appears to Be Based Upon an Unfounded Assertion that Customer Deliveries to the Southern System will Continue to Drop, which Does Not Account for Significant Indicators Suggesting Otherwise

1. A Brief Overview and Outlook for US Gas Production and Demand Suggests Less Long-Term Exports to Mexico

The natural gas market in the United States (U.S.) has been thoroughly transformed by increased production from shale gas through the use of high pressure liquids to fracture ("frack") shale rock in horizontal rather than vertical drilling arrays, and other unconventional sources, with the rising gas production numbers gradually trending up starting early in the new millennium.[107] Average annual dry gas production rose from only 1.0 Bcfd in the year 2000 to 16.2 Bcfd by

[105] Response to ORA-SCG-02 Q.1(a).

[106] Marelli, p.21.

[107] Figures 1 & 2 shown in Navigant's NG Market Notes, October 2014 issue, p.3 This is shown as an attachment in this exhibit.

2010, and was at 38.3 Bcfd towards the end of 2014.[108] Those average annual gas dry production numbers are projected to go over 80 Bcf/d by 2020, based on forecasts by Navigant.[109] As a result of the abundant supply in the market, natural gas prices have fallen from their highs of over $12 per mmbtu in July 2008 to just under $3 per mmbtu to date. The EIA 2015 Report projects the U.S. will transition from being a modest net importer of natural gas to become a net exporter by 2017.[110]

The abundant gas supplies in the U.S. market made possible by the record levels of domestic production from unconventional resources especially in the last five years has resulted in a glut of gas supply. With U.S. production growing faster than domestic use, the U.S. is projected to become a net exporter of natural gas. But while the outlook is for increased U.S. exports of gas to countries such as Mexico, the long-term forecast sees lower pipeline exports in later years as Mexico begins to increase its domestic production that could be made possible by recent constitutional reforms allowing for foreign investment in production of Mexican gas and other energy sectors.[111]

2. Applicants' Fears about the Threat of Growing U.S. Gas Exports to Mexico and Growing Demand for Gas in Mexico Do Not Account for Significant Indicators

At page 7 of the Application, Applicants state "Customer deliveries are expected to continue to drop as supplies on El Paso's South Mainline are diverted to high-value Mexican markets."[112] ORA found no underlying SoCalGas analyses

[108] Figure 2, Navigant's NG Market Notes, Oct.2014, p.3

[109] Figure 1, Navigant's NG Market Notes, Oct.2014.

[110] U.S. Energy Information Administration Annual Energy Outlook 2015 dated April 2015, p.E-11 available at http://www.eia.gov/forecasts/aeo.

[111] The long-term impact of Mexico's constitutional reforms to its energy landscape remains to be seen. A Report published by Bentek titled "Mexico's New Energy Landscape" dated March 2015 describes Mexico's entire energy sector as "undergoing unprecedented liberalization and reform, creating important opportunities for foreign production, power and midstream companies." It could still be too early to tell how successful this endeavor for reforms will be since the law was only signed on December 20, 2013. The Report is included as an Attachment to this exhibit.

[112] Application (A.)13-12-013, p.7.

behind this statement.[113] Rather the statement is based on public information about the structure of the natural gas market in Mexico.[114]

Also at page 7 of the Application, Applicants state "Increasing Mexican exports may reduce flow into Blythe."[115] This statement is based on witness Chaudhury's projections at Section III of testimony on potential natural gas exports to Mexico via the El Paso South Mainline, including information on El Paso's recently completed new laterals/expansion of laterals off of South Mainline to facilitate export to Mexico.[116] Applicants believe these additional exports to Mexico will directly compete with available supplies into Ehrenberg. As entities serving the new gas load in Mexico sign long term contracts for capacity with El Paso, the likely result will be substantially lower flowing supplies available to reach Ehrenberg.[117]

A visit to the website of the U.S. Energy Information Administration (EIA) confirms the rising trend of exports of gas to Mexico.[118] But while there are currently rising exports of gas to Mexico, ORA notes that the U.S. EIA projections through the year 2040 point to a longer term decline in net export outlook. These EIA projections were contained in two successive recent reports by the agency, the Annual Energy Outlook 2014 (AEO2014) and Annual Energy Outlook 2015 (AEO2015).

The EIA 2015 Report states:[119]

> In the AEO2015 Reference case, the United States becomes an overall net exporter of natural gas in 2017, one year earlier than in AEO2014, and a net pipeline exporter of natural gas in 2018, three years earlier than in AEO2014. In the AEO2015 Reference case, imports from Canada, which largely enter the western United States, and exports into Canada, which generally exit out of the East, are generally lower than in the AEO2014

---

[113] Response to ORA-NSP-SCG-02 Q.8(a).

[114] Response to ORA-NSP-SCG-02 Q.8(a).

[115] Application, p.7.

[116] Response to ORA-NSP-SCG-02 Q.9.

[117] Response to ORA-NSP-SCG-02 Q.9.

[118] www.eia.gov

[119] U.S. Energy Information Administration Annual Energy Outlook 2015 dated April 2015, p.E-11 available at http://www.eia.gov/forecasts/aeo.

> Reference case. Imports from Canada remain lower in the AEO2015 Reference case than in the AEO2014 Reference case through 2040, while exports to Canada are higher in the AEO2015 Reference case from 2021 to 2028, before decreasing below AEO2014 levels through 2040. Net pipeline imports from Canada fall steadily until 2030 in AEO2015, then increase modestly through 2040, when growth in shale production stabilizes in the United States but continues to increase in Canada.
>
> Net pipeline exports to Mexico increase almost twofold in the AEO2015 Reference case from 2017 to 2040, with additional pipeline infrastructure added to enable the Mexican market to receive more natural gas via pipeline from the United States. However, pipeline exports to Mexico in the later years of the AEO2015 Reference case are lower than projected in the AEO2014 Reference case, because Mexico is assumed to increase domestic production as a result of constitutional reforms that permit more foreign investment in its oil and natural gas industry.

While the net pipeline exports to Mexico are projected to increase almost twofold from 2017 to 2040, the last statement in the above quote from U.S. EIA projects lower pipeline exports to Mexico in the later years of the AEO2015 Reference case attributable to the possibility that energy reforms in Mexico could begin to take hold and result in increased in domestic production. If the Applicants' pursue a pipeline project whose useful life could extend over 60 years, then the long term outlook for a decline in U.S. gas exports to Mexico could leave the Applicants' ratepayers footing the bill for a stranded pipeline asset to the extent it becomes idled capacity. At best, the Applicants' should prepare for the immediate trend of rising gas exports to Mexico but not rush into assuming that physical infrastructure is the best response. Assuming a gas pipeline had only 60 years of useful life, and if gas exports start to decline in 2040, then that still leaves over two-thirds of the useful life of the pipeline project at risk to become a stranded asset.

A similar assessment of increased natural gas production outstripping domestic consumption, with the U.S. projected to become a net exporter of natural gas was made in the previous EIA 2014 Report, which also points to a possibility of reduced need for U.S. natural gas exports to Mexico in the future because of the energy reforms there:[120]

> In the AEO2014 Reference case, natural gas production grows by an average rate of 1.6%/year from 2012 to 2040, more than double the 0.8% annual growth rate of total U.S. consumption over the period. The growth in production meets increasing demand and exports (liquefied natural gas [LNG] and pipeline exports), while also making up for a drop in natural gas imports. The United States becomes a net exporter of natural gas before 2020.
>
> The development of shale gas resources spurs growth in natural gas production, with producers seeing higher prices as a result of growing demand, especially from both the industrial and electricity generation sectors.
>
> The United States transitions from being a net importer of 1.5 Tcf of natural gas in 2012 to a net exporter of 5.8 Tcf in 2040, with 88% of the rise in net exports (6.5 Tcf) occurring by 2030, followed by slower growth through 2040 (Figure MT-42).
>
> Net LNG exports, primarily to Asia, increase by 3.5 Tcf from 2012 to 2030, then remain flat through 2040. Prospects for future LNG exports are uncertain, depending on many factors that are difficult to anticipate. The increase in net LNG exports to Asia through 2030 accounts for 55% of the rise in total net natural gas exports, with the remainder coming from decreased net pipeline imports from Canada and increased net pipeline exports to Mexico.
>
> The next-largest growth market for U.S. natural gas exports is pipeline exports to Mexico, which increase from 0.6 Tcf in 2012 to 3.1 Tcf in 2040. The increase in exports to Mexico reflects a growing gap between Mexico's natural gas consumption and production. However, Mexico's recently enacted legislation to restructure its oil and gas industry could reduce the need for U.S. natural gas exports to Mexico in the future.

The EIA is not alone in projecting the positive outlook for U.S. gas production, lower domestic consumption, and prospects to become a net natural gas exporter. Table CP5 of the 2014 EIA Report compares the AEO2014 Reference case

[120] U.S. Energy Information Administration Annual Energy Outlook 2014 dated April 2014, p. MT-22 and is available at http://www.eia.gov/forecasts/aeo

projections with projections by other groups in the oil and gas industry.[121] Overall, like the AEO2014 Reference case, the other projections (independently prepared from those of the EIA) shown in Table CP5 indicate the United States becomes a net natural gas exporter by 2020, although there is some difference with AEO2014 regarding the magnitude of projected export levels and whether those exports start to decline, and if so, when declines are projected to take place.[122]

A research study in February 2015 prepared by a researcher from the UC Davis Institute of Transportation Studies supports the case for greater U.S. exports due to abundant supplies of U.S. gas.[123] The study entitled "North American Resources and Natural Gas Supply to the State of California" also supports the EIA 2015 outlook for natural gas in the U.S. and to California. The modeling in the study corroborates that expected shale production growth in the U.S. is very strong and could exceed 50 bcfd and account for well over half of US domestic gas production by the 2020s (illustrated in Figure 9 of the study).[124] The study projects that US LNG exports could approach 6 bcfd by the mid-2020s.[125] However, the study projects overall U.S. production to plateau later in this decade "not for lack of resource, but because Canadian natural gas production begins to grow" and "international market rebalancing limits the commercial opportunity for LNG exports from the U.S."[126] The study predicts that production growth in Canada will ultimately push gas supply into northern California through the PGT system at Malin.[127] In addition, the study also

---

[121] The US EIA 2014 Report, p.CP-10. Comparisons in Table CP5 are shown against the projections by IHS Global Insight (IHSGI), Energy Ventures Associates (EVA), ExxonMobil, ICF International Incorporated (ICF), BP PLC (BP), Interindustry Forecasting Project at the University of Maryland (INFORUM), among others.

[122] Id., pp.CP-9 through CP-12.

[123] "North American Resources and Natural Gas Supply to the State of California", A White Paper by Kenneth B. Medlock III, Ph.D., UC Davis Institute of Transportation Studies dated February 18, 2015. Available at http://steps.ucdavis.edu/

[124] Medlock White Paper, pp.21-22.

[125] Medlock, p.22.

[126] Medlock, p.22.

[127] Medlock, p.22.

projects that the "production growth in the Permian Basin finds its way into southern California along the El Paso north and south lines."[128]

In a presentation to the CEC Natural Gas Stakeholder Working Group on April 16, 2014, Kinder Morgan presented its outlook for Mexican exports to grow and continue to take up pipeline space; however, Kinder Morgan points out that growth is occurring at a time when regional supply is growing and Southwest demand is declining.[129] According to Kinder Morgan, if Mexico develops its shale gas resources sooner, then expect more of impact (downward pressure) on US exports in Southeast Mexico.

Therefore, while US exports of gas supplies to Mexico are forecast to rise, perhaps to as much as twofold from 2017 through 2040, the rising trend does not appear to hold through the long-term because of Mexico's recent energy reforms that could help that country develop its own vast domestic resources of natural gas and increase its domestic production. There are already indications that foreign investors are already paying attention.[130] The Wall Street Journal (WSJ) reports the National Hydrocarbons Commission, which is Mexico's oil regulator, has said it approved four Norwegian companies during the week of April 17to focus on the oil-rich Gulf of Mexico. In addition, the WSJ report says there are 22 more firms seeking permission to carry-out geological mapping to provide data possibly leading to significant new oil and gas discoveries.[131]

Mexico's energy reforms are expected to bear fruit on the economic front. It may still be too early to predict the ultimate outcome of Mexico's energy reforms.

---

[128] Medlock, p.22.

[129] Kinder Morgan Presentation to the CEC Natural Gas Stakeholder Working Group on April 16, 2014 entitled "Potential Implications to California of Mexican Energy Reform" available on the CEC website at www.energy.ca.gov/naturalgas/documents/201404/presentations

[130] Reported by several sources, including the Bentek Report entitled "Mexico's New Energy Landscape" dated March 2015; The Economist article entitled "A new Mexican Revolution" dated Nov. 15, 2014; Bloomberg Energy news bulletin entitled "US Natural Gas Exports Will Fire Up in 2015" dated Nov.6, 2014; and the Wall Street Journal news article entitled "Mexico's Energy Overhaul Draws Geological-Data Firms" dated April 17, 2015. These reports are included as Attachments to this exhibit.

[131] WSJ article "Mexico's Energy Overhaul Draws Geological-Data Firms," April 17, 2015.

Published news reports regarding Mexico's economy say that Mexico's economic growth in 2014 was only modest and the impact on growth of Mexico's energy reforms is so far not yet readily apparent from economic data.[132] Based on the slower pace of growth and the falling oil prices, current indications show a lowering of growth expectations for Mexico in 2015.[133]

The fact that Mexico's demand for gas has been on the rise can be verified from Figure 4 of a Congressional Research Service Report (CRS Report) on Mexico's Oil and Gas Sector.[134] Figure 4 shows Mexican gas production, consumption, and imports of natural gas for the period from 2002 through 2013. The CRS Report states that as a result of Mexico's gas demand rising more than its gas production, its imports of gas have been increasing.[135] The CRS Report quotes the EIA assessment that Mexico's gas resources are significant (i.e., sixth highest globally.)[136] The CRS Report also corroborates the long term prospects for increased Mexican shale gas production saying that "Mexico, through Pemex, has already started exploring some of its unconventional formations. A limited number of test wells have been drilled, but Pemex has ambitious plans for scaling up development and production over the next 10 years."[137]

3. Applicants' Assertions of Increasing Electric Generation Demand Ignore Decreasing Energy Demand Forecasts

Applicants assert the threat from increases in EG demand particularly since the closure of the SONGS plant.[138]

---

[132] Wall Street Journal news article "Mexican Economy Expanded Modestly in 2014" dated Feb.20, 2015 included as an attachment in this Exhibit.

[133] WSJ, "Mexican Economy Expanded Modestly in 2014". Mexico is said to finance a third of its federal budget through oil revenues.

[134] Figure 4, Congressional Research Service Report on Mexico's Oil & Gas Sector dated January 27, crs/R43313, p.10. available at *https://www.fas.org/sgp/**crs**/.../R43313.*

[135] Congressional Research Service Report on Mexico's Oil & Gas Sector dated January 27, crs/R43313, p.10.

[136] Congressional Research Service Report on Mexico's Oil & Gas Sector dated January 27, crs/R43313, p.11.

[137] Congressional Research Service Report on Mexico's Oil & Gas Sector dated January 27, crs/R43313, p.11.

[138] Marelli, p.6

ORA does not expect increases in EG demand from the permanent closure of SONGS to be met only by increases in gas-fired generation as explained below. As contemplated by the Commission in its decision addressing the permanent SONGS closure, at least 676 MW of the procurement authority for 2,400 MW -3,300 MW must be from preferred resources consistent with the loading order.

SONGS Units 2 and 3 permanently closed in June 2013.[139] SONGS had supplied 2,246 MW of load power to the LA Basin and San Diego until 2011.[140] The issue of addressing the resources to replace the lost capacity from SONGS' permanent closure is included in the Commission's umbrella proceeding known as the Long Term Procurement Proceeding (LTPP).[141] The combined procurement authority in D.13-02-015 (i.e., 2013 Track 1) and D.14-03-004 (Track 4 in 2012 LTPP) in R.12-03-014, which latter decision authorizes long- term procurement for local capacity requirements due to the permanent retirement of SONGS, provides SCE with authority for a total procurement capacity from 1,900 MW to 2,500 MW while the decision authorizes SDG&E a total procurement capacity from 55 MW to 800 MW. In D.14-03-004 Ordering Paragraph #1, the Commission ordered that the authorized procurement must abide by guidelines set forth in the decision's Table 1. The guidelines in the table provide that of the 1,900 to 2,500 MW total procurement authorization for SCE, at least 1,000 MW but no more than 1,500 MW of local capacity must be from conventional gas-fired resources while at least 50 MW must be procured from storage resources.[142] More importantly, based on the guidelines in D.14-03-004 O.P.#1, at least 500 MW must be from preferred resources consistent with the Commission's loading order while at least 200 MW but no more than 500 MW must be procured from any resources able to meet local capacity requirements. The guidelines further state that "Subject to the overall cap of 2,500 MW, any additional local capacity may only be procured through preferred resources

[139] FOF#2, D.14-03-004.

[140] FOF #4, D.14-03-004.

[141] More information on the LTPP available in the Commission's website at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP

[142] O.P.#1, D.14-03-004, pp.141-143.

consistent with the loading order."[143] For SDG&E, D.14-03-004 O.P.#2 authorizes the utility to procure between 500 MW and 800 MW of electrical capacity to meet capacity requirements by end of 2021. Of the authorized procurement amount, the guidelines provide that at least 175 MW must be procured from preferred resources consistent with the loading order while at least 25 MW must be procured from energy storage resources. Overall, these guidelines provide for at least 676 MW from preferred resources consistent with the loading order.

Furthermore, the Applicants' assertions of increasing electric generation demand are unwarranted given the lower forecasts of energy demand based on the latest forecast report by the California Energy Commission (CEC). As described below, the lower forecasts of energy demand are due to more pessimistic forecasts of economic growth in California. Further, the California Renewables Portfolio Standard (RPS) is mandated by law, and hence, is projected to ramp up renewable energy generation by 2020. The 2014 California Gas Report states that "California is currently on track to meet a 33% Renewable Portfolio Standard by 2020."[144] The Gas Report shows the impact of renewable generation and energy efficiency programs on gas demand through the year 2030 in terms of substantial gas savings over the 2013 level.[145]

The CEC 2014 Integrated Energy Policy Report (IEPR) Update states that the latest projections of California energy demand for the period 2015-2025 are lower, and results from more pessimistic projections of economic growth in California compared to those used in the 2013 forecast report.[146] The CEC 2014 IEPR states:[147]

> By 2024, statewide peak demand in the updated mid scenario is projected to be 1.8 percent lower than the forecast mid case developed in 2013. Updated forecast results for individual planning areas and updated

[143] O.P.#1, D.14-03-004.

[144] 2014 California Gas Report Prepared by the California Electric & Gas Utilities, p.8.

[145] 2014 California Gas Report, p.7.

[146] CEC 2014 Integrated Policy Report Update, p.7.

[147] CEC 2014 IEPR, p.7.

> managed forecasts for the investor-owned utility service territories, which incorporate additional achievable energy efficiency savings, are also lower relative to the forecast developed in 2013. The Energy Commission adopted the California Energy Demand Updated Forecast 2015–2025 at the January 14, 2015 Business Meeting.

California already relies on natural gas generation for as much as 50 percent of its electricity supplies.[148] The CEC's 2013 IEPR states that the closure of San Onofre in 2012 requires some replacement generation from a combination of natural gas and preferred resources. In addition, the 2013 IEPR projects that by 2020, 33 percent of generation will be met with renewable sources, which will result in less natural gas needed to meet load.[149] The CEC 2013 IEPR explains how the RPS mandate could impact natural gas generation in California:[150]

> Some natural gas generation may be needed to integrate intermittent renewable resources, but daily and intra-day analysis would be necessary to further examine this issue. California's Renewables Portfolio Standard mandate of 33 percent renewables by 2020 is leading to a build-out of renewable generating capacity that is producing energy that likely would have otherwise been met by natural-gas fired generating units. However, because of the intermittent nature of renewable generation, natural gas-fired units may be needed to fill in short-term mismatches between supply and demand. Going forward, it is important that the natural gas system has the flexibility to accommodate the short-term ramps up and down of natural gas units that will be required to integrate renewables. Spare pipeline and storage capacity in California provides a degree of flexibility to the gas system that will allow it to better respond to the changing power generation needs of the state.

The California PUC implements and administers the RPS compliance rules for California's sellers of electricity. Currently, the RPS procurement status of the percentage under contract for 2020 of the large utilities shows 31.3% for PG&E, 23.5% for SCE, and 38.8% for SDG&E, the latter showing the most percentage RPS procurement under contract for 2020 of the 3 large utilities.[151]

---

[148] CEC 2013 IEPR, p.239.

[149] CEC 2013 IEPR, p.241.

[150] CEC 2013 IEPR, pp.239-240.

[151] More information regarding the California RPS is available at http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm

B. The Applicants' Reasons for Selecting the Proposed North-South Project As the Best Physical Response Appears Unsubstantiated[152]

Applicants assert the reasons below for selecting the proposed Project over any other physical or non-physical alternative to address the Southern System reliability. In eight different subsections, ORA explains why these reasons are not properly substantiated.

1. Applicants' Assert, without Substantiation, that the Proposed Project Provides A Needed Physical Solution Because Non-Physical Solutions Will Not Solve The Problem

Witness Marelli states the Applicants have looked at a number of potential non-physical solutions and concludes that none of them will provide the tools needed for the Southern System reliability problem.[153] In testimony, the potential non-physical solutions "looked at" by the Applicants include: (1) contracting for upstream supplies; (2) transfer of Southern System responsibility back to Gas Acquisition; (3) supplementing or replacing the existing System Operator tools with a minimum flowing supply requirement for all end-use customers; and (4) short term tools such as the MILC with Gas Acquisition and baseload contracts.[154] The Applicants dismiss these non-physical solutions. In discovery, ORA sought the analysis behind the conclusion that non-physical solutions will not solve the problem. However, in its data response, the Applicants simply refer to the December 20, 2013 testimony of Ms. Musich (Section VII) and Mr. Bisi (Section VII).[155] No additional analysis of the non-physical solutions were provided.

[152] Marelli, pp.21-25.

[153] Marelli, p.17.

[154] Marelli, pp.17-20.

[155] Response ORA-NSP-SCG-03 Q1 (a-e).

In Mr. Bisi's case, he states that none of the infrastructure alternatives considered by the Applicants will resolve the reliability issue at the Rainbow Corridor. Mr. Bisi explains:[156]

> The issue of reinforcing the Southern System with a new pipeline from the Northern Transmission System was not discussed in any of these advice letter filings because this interconnect does not expand capacity to a capacity constrained area, and is not needed for that purpose. In other words, any of the pipelines discussed in more detail below will transport supply from the Northern Transmission System to the Southern System in the event of low deliveries at Blythe or Otay Mesa; however, they do not provide for additional capacity to move those gas supplies south into the capacity constrained areas of the Rainbow Corridor or San Diego.

ORA attempted once again to obtain the analysis behind the "efforts"[157] previously reviewed by the Applicants. To the ORA request for an analysis of the "efforts" that enabled SoCalGas to conclude that each of the mitigation efforts will not solve the reliability issue for the Southern System and is a "short-term" effort, ORA obtained the following in response. Applicants state:[158]

> The mitigation efforts described by Ms. Marelli are "short-term" because they rely on the economic availability of supply at Ehrenberg. Due to the expansions of demand for natural gas in Mexico described by Mr. Chaudhury, SoCalGas and SDG&E do not believe such supply will be economically available after 2020. For example, SoCalGas will not be able to obtain baseload supplies at Ehrenberg for SoCalGas border + 8 cents, +20 cents, or even +30 cents. Gas Acquisition will not be able to justify the extremely expensive long-term contract and supply commitments necessary to fulfill its current obligations under the MILC. The cost of supply at Ehrenberg will become so high that it will be uneconomical to deliver such supply to the Los Angeles citygate even if the BTS rate for transport of such gas on the Southern System is discounted all the way down to zero.
>
> Furthermore, the mitigation efforts are short-term because they do not provide Southern System customers the reliability afforded other customers throughout the system. They are susceptible to flowing supply failures of El Paso's Southern System supplies. Whereas other parts of the system can be

[156] Bisi, p.9.

[157] See Marelli, p.12.

[158] Response to ORA-NSP-SCG-09 Q1(a).

> protected against potential flowing supply failures with storage, SoCalGas' Southern System customers will not have effective access to storage without the long-term solution represented by the North-South pipeline proposal.
>
> SoCalGas and SDG&E have historically had problems with supply reliability during cold weather events that periodically affect the Southwest US. These problems resulted in the curtailment of end use customers in 1989 and again in 2011. These supply problems have been documented by the Federal Energy Regulatory Commission (FERC) in the FERC/NERC Staff Report on the 2011 Southwest Cold Weather Event.

The Applicants seem to paint a very dire scenario of imminent increases in the cost of supply at Ehrenberg after the year 2020 due to the expansion of demand in Mexico. If the SoCalGas S.O. recognizes a need to engage in gas hedging for price protection of its gas supplies, then it could consider non-physical alternatives.

2. Applicants' Have Provided No Basis to Support the Assertion that Adding Physical Capacity Effectively Eliminates the Southern System Minimum Flow Requirement

In testimony and data response, Applicants assert that the Southern System minimum flow requirement is necessary because customers and shippers often choose not to deliver gas supply to their Blythe and Otay Mesa receipt point for economic reasons.[159]

Further, in testimony, Applicants state the Project as well as the two other infrastructure alternatives considered, would add approximately 800 MMcfd of north-to-south flow capacity which would effectively eliminate the Southern System Minimum flow requirement.[160] When asked whether it is absolutely necessary to eliminate the Southern System minimum flow requirement, Applicants responded:

> SoCalGas and SDG&E believe it is in the best interest of our customers to have a gas transmission system that is not dependent upon either having supply delivered at a specific location or face customer curtailment and jeopardize system integrity. In that regard, we believe that a Southern System minimum flow requirement has been relied upon for far too long,

[159] Response to ORA-NSP-SCG-11 Q3(e).

[160] Marelli, p.21.

> and that it is necessary to propose a physical alternative to replace it for the reasons specified in our application.[161]

However, Applicants are still keeping the minimum flow requirement of 100 MMcf/d at Blythe even if they construct the North-South Project.[162] If the minimum flow requirement of 100 MMcf/d at Blythe is necessary even with the construction of the North-South Project, it is an indication that the North-South project does not directly address the purported reliability issues justifying it.

3. Although Applicants Assert that the North-South Project Provides Southern System Customers with Access to Storage To Maintain Reliability, It Appears the Project Would Not Have Prevented Any of the Recent Curtailment Events

In testimony, Applicants identify the provision of access to storage and additional receipt points as the primary reason for proposing the North-South Project.[163] At present, Southern System customers do not have physical access to storage.[164] The provision of access to storage to Southern System customers is another reason the Applicants prefer the North-South Project as they explain in response to ORA's data request:[165]

> The North-South Project and Cross Desert Project provide physical access to storage supplies for the Southern System; the River Route does not. Please refer to pages 9 – 14 of the Prepared Direct Testimony of David M. Bisi in A.13-12-013.

But as explained by the Applicants, even though the Project is said to provide access to SoCalGas storage supplies and is the primary reason for proposing the Project, the said Project would not have prevented the occurrence of the nine curtailment events identified in response to ORA-NSP-SCG-06 Question 3a that are

---

[161] Response to ORA-NSP-SCG-11 Q3(c).

[162] Marelli, p.23.

[163] Marelli, p.21.

[164] Response to ORA-NSP-SCG-03 Q4(b).

[165] Response to ORA-NSP-SCG-03 Q5(g).

the examples of the type of challenges to reliable service Applicants claim the Project will solve.[166]

Given that the Project was primarily selected because of the provision of physical access to storage supplies for the Southern System, would the Project have prevented the two system curtailment events that occurred on Feb 3, 2011 and Feb.6, 2014 if the Project had been built and was in operation? No. Applicants explain:[167]

> The curtailment events on February 3, 2011 and February 6, 2014 were the result of gas supply shortages across the entire system. Storage supplies from SoCalGas' Honor Rancho facilities were needed to substitute for these lost supplies, and therefore would have been unavailable to transport to the Southern System via the North-South Project in order to prevent these two curtailment events.

Neither would the North-South Project have prevented the December 2013 event at the Southern System. Applicants explain:[168]

> With respect to the testimony on page 10, lines 9-16, SoCalGas and SDG&E do not believe that either the North-South Pipeline nor deliveries from Honor Rancho would have been able to support the Southern System on December 9, 2013. SoCalGas and SDG&E were short of supply across their entire system during that event, and there were no supplies available on its Northern System to transport to the Southern System.

In addition, Applicants plainly admit that neither the North-South Project nor deliveries from Honor Rancho would have been sufficient to eliminate the curtailment watch or to avoid purchases at the Otay Mesa receipt point over several days during the January 2013 curtailment watch:[169]

> With respect to the testimony on page 9, lines 11-16, SoCalGas and SDG&E do not believe that either the North-South pipeline nor deliveries from Honor Rancho would have been sufficient to eliminate the curtailment watch or to avoid purchases at the Otay Mesa receipt point. During this event, the level of demand on the Southern System,

[166] Response to ORA-NSP-SCG-11 Q3(g).

[167] Response to ORA-NSP-SCG-11 Q3 (f).

[168] Response to SCGC DR#4 Q4.16.

[169] Response to SCGC DR#10 Q10.2.

particularly in the Rainbow Corridor and in San Diego, was very high. In fact, the San Diego demand on January 14 and 15 was 659 and 639 MMcfd, respectively, which exceed the 630 MMcfd capacity of SDG&E system. While SoCalGas had ample supply available on its Northern System, additional supply delivered at Moreno via the North-South pipeline could not be redelivered through the Rainbow Corridor to the SDG&E system – the SDG&E system was simply out of capacity.

Moreover, Applicants explain that the Project is not designed to improve the capacity of the SDG&E system.[170] Thus, the Project would not have addressed issues regarding nine curtailment events Applicants listed in response to ORA's request in Question 3a that "were necessary to perform pipeline safety-related work on SDG&E's Transmission Line 3010, and resulted in a capacity reduction on the SDG&E system."[171]

4. Although Applicants Note that the Project Provides Southern System Customers with Access to Additional Receipt Points, Such Access Would Not Have Prevented Recent Curtailment Events

In testimony, witness Bisi also describes the Project's ability to transport supply delivered at the North Needles, South Needles, Kramer Junction, Wheeler Ridge, and Kern River Station receipt points in addition to the transport of storage supplies from the Honor Rancho storage.[172] The provision of access to many more receipt points is another reason the Applicants claim to have chosen the Project as an infrastructure alternative.

Applicants explain:[173]

The North-South Project and the Cross Desert Project provide access to many more receipt points than the River Route Pipeline, and therefore would provide a higher level of insurance against disruptions caused by force majeure conditions in supply basins than the River Route alternative. However, all three alternatives provide a higher level of insurance against

[170] Response to ORA-NSP-SCG-11-Q3(g).

[171] Response to ORA-NSP-SCG-11 Q3(g).

[172] Bisi, p.14.

[173] Response to ORA-NSP-SCG-03 Q5(j).

such disruptions relative to the present situation, where the Southern System is essentially dependent upon supplies delivered on the El Paso pipeline from the Permian and San Juan Basins.

However, when asked whether the access to the additional receipt points described would have prevented the nine additional curtailment of service events identified in response to ORA-NSP-SCG-06 Question 3a), Applicants confirm that the Project would not have done so for the same reasons explained in response to ORA-NSP-SCG-11 Question 3g.[174] In that response referenced by the Applicants, the project would not have done so because the North-South Project is not designed to improve the capacity of the SDG&E system, and therefore access to additional receipt points, similar to access to SoCalGas storage supplies afforded by the North-South Pipeline, would not have prevented these nine curtailment events.

5. Applicants Acknowledge that the Project Unnecessarily Expands SoCalGas' Firm Backbone Capacity

In testimony, Applicants explain a preference for the Project over the other two alternatives they considered because it expands SoCalGas' firm backbone capacity. Witness Marelli states that "Unlike the other two physical alternatives examined by SoCalGas/SDG&E, the North-South Project would expand SoCalGas' firm backbone capacity from 3,875 MMcfd to 4,175 MMcfd."[175]

Witness Bisi states in testimony:[176]

> Again, increased receipt capacity was not a problem that SoCalGas was seeking to solve with any of these three pipelines, but is rather an added benefit that the market and our customers may appreciate. SoCalGas believes that its current receipt capacity of 3,875 MMcfd is sufficient to meet the long term demand requirements of our customers and also provides a sufficient level of excess, or "slack," capacity per Commission guidelines.[9]

---

[174] Response to ORA-NSP-SCG-11 Q3(i).

[175] Marelli, p.22.

[176] Bisi, pp.16-17.

Applicants have failed to show a need for expanded SoCalGas firm backbone capacity in order to address Southern System reliability issues. Indeed, the Applicants acknowledge in testimony that the current receipt capacity is sufficient to meet long term requirements and provides a sufficient level of excess of slack capacity. In SoCalGas advice letter 4662 filed in July 2014, SoCalGas explains that it continues to hold adequate backbone transmission capacity and has a reserve margin of backbone capacity consistent with Commission policy. SoCalGas expects to hold a reserve margin of 37% in 2014 and to retain an average reserve margin of 39% through 2030.[177] In Table 1 of AL 4662, SoCalGas shows average reserve margin of 40% from 2020 through 2030 under a one- in-ten-Year Cold and Dry-Hydroelectric Condition.[178]

ORA asked the Applicants to explain how the presence of an intrastate pipeline such as the North-South project would prevent Southern System customers from being "at the mercy of supply-related problems outside California."[179] The gas curtailment events on February 3, 2011 and February 6, 2014 were the result of gas supply shortages across the entire system.[180] The Applicants were asked to describe how the presence of the North-South project would have changed Applicants' ability to handle "supply-related problems outside of California" such as occurred on February 4-6, 2014.[181] In response, Applicants stated:

> The North South pipeline would provide SoCalGas/SDG&E customers on the Southern System access to all of the supply basins plus storage to Northern System customers, reducing the likelihood of problems, like that experienced on February 4-6, 2014. If the North South pipeline were in place, as well as the Low Operational Flow Order proposed in A.14-06-021, SoCalGas/SDG&E would expect adequate supplies to meet Southern system demand up to our system design criteria. Those supplies could be delivered at ANY receipt point and then transported to the Southern System.

---

[177] SoCalGas AL 4662, p.2.

[178] Table 1, SoCalGas AL 4662, p.2

[179] Application, p.9.

[180] Response to ORA-NSP-SCG-11 Q.3(f).

[181] ORA-NSP-SCG-03 Q2(e).

In spite of Applicants' asserted expectations, a similar question was asked by SCGC, to which Applicants frankly admitted that the Project would not have prevented the events on February 2011.[182]

> With respect to the testimony on page 8 lines 11-21 and page 9, lines 1-4, SoCalGas and SDG&E do not believe that either the North-South pipeline or deliveries from Honor Rancho would have been able to support the Southern System on February 2 and 3, 2011. SoCalGas and SDG&E were short of supply across their entire system during that even, and there were no supplies available on its Northern System to transport to the Southern System. Because our Southern System is not interconnected to the same extent as the rest of our transmission system, when we have overall supply issues, the first place we notice that is on the Southern System, and that lack of interconnectedness limits our options. SoCalGas and SDG&E recently filed an application proposing a "low OFO" procedure would help in these instances of overall system supply shortages. If the low OFO procedure were in place and adequate supplies were delivered, the North-South pipeline would allow customers to deliver their supplies at the receipt point of their choice and allow SoCalGas & SDG&E to deliver that supply throughout the system.

6. Applicants Assert No Available Existing Physical Facilities for Purchase

The Applicants' state that another potential physical option to address Southern System supply issues is for SoCalGas to purchase existing facilities from another entity.[183] Applicants state that they do not believe that there presently are any physical facilities that could be purchased that would provide a reasonable and economic solution to impending supply-related Southern System cost and reliability problems.[184] If it makes economic sense to buy an existing facility to address the Southern System issues, then Applicants say they could do it. As an example, Applicants described their past purchase of the Questar Southern Trails pipeline. SoCalGas did upgrades and remediation of environmental contamination from

[182] Response to SCGC DR#10 Q.10.1.

[183] Marelli, p.22.

[184] Marelli, p.22

Questar's operations.[185] The Southern Trails pipeline is now SoCalGas Line 6916, which became operational in December of 2012 and provides a new connection between SoCalGas' Northern Zone and Southern Zone transmission systems. It is said to reduce the Southern System minimum flow requirements up to 80 MMcfd, depending upon scheduled supplies.[186] In spite of the recent purchase and operation of Line 6916, Applicants state that no pipeline facilities in Southern California are currently being offered to the marketplace for sale publicly.[187]

Applicants' argument again assumes that a physical alternative is required to meet the Southern System reliability issues as Applicants have defined them. ORA does not dispute that there is no pipeline available for purchase by Applicants that would have provided similar operational flexibility to the Project, but because the Project is not necessary this showing is not relevant to ORA's analysis.

7. Enhances the Reliability and Operational Flexibility of the Transmission System[188]

SoCalGas witness David Bisi states:[189]

> A new pipeline, such as the North-South Project that SoCalGas prefers, provides operational flexibility that is maintained, controlled, and operated by SoCalGas within the jurisdiction and oversight of the Commission, and is not reliant on outside companies to maintain their pipeline systems and contractual obligations upstream of SoCalGas.

ORA does not dispute that the North – South project would enhance the reliability and operational flexibility of SoCalGas' transmission system, but the issue is whether such enhanced reliability and flexibility is part of a reasonable solution to the particular problem of Southern System reliabilty, and as discussed, ORA does not agree that it is.

---

[185] Marelli, p.22.

[186] Marelli, p.22.

[187] Marelli, p.22.

[188] Updated Testimony of David Bisi in A.13-12-01`3, pp.19-21

[189] Bisi. p.18.

8. Other Problems Left Unsolved by the Project

Does the Project eliminate the need for the MILC or any of the S.O. tools? The Applicants initially responded that there would probably be no need for MILC[190] and reiterated this in another data response given the revised North-South Project.[191] But the Applicants still expect to continue to use the S.O. tools to address the Southern System reliability issue "under the unlikely event that customers and shippers are not delivering at least 100 MMcfd of supply at Blythe under a high sendout condition."[192]

The Applicants' response below explain that the proposed Project on a stand-alone basis does not provide a solution to the Southern System reliability problem:[193]

> The curtailment events on February 3, 2011 would have been avoided had the North-South Project been in existence and SoCalGas was able to engage in spot purchase and sales from non-southern system receipt points and storage to support Southern System reliability. The curtailment event on February 6, 2014 would not have been avoided even if the North-South Project been available and SoCalGas was able to engage in spot purchase and sales from non-southern system receipt points and storage to support Southern System Reliability. This problem would be avoided in the future by the adoption of the Low OFO/EFO proposal as presented in A.14-06-021.

Does the Project resolve the problem of customers and shippers delivering less gas into the SoCalGas/SDG&E system than they are burning during the times of system stress? Applicants plainly admit that the Project will not provide a solution to the problem.[194] This is because the Project will only move gas supply **already** on the SoCalGas/SDG&E system to other parts of the SoCalGas/SDG&E system.[195]

[190] Response to ORA-NSP-SCG-02 Q6(c).

[191] Response to ORA-NSP-SCG-08 Q3(a).

[192] Response to ORA-NSP-SCG-08 Q3(b).

[193] Response to ORA-NSP-SCG-09 Q2(b).

[194] Response to ORA-NSP-SCG-08 Q2(b).

[195] Response to ORA-NSP-SCG-08 Q2(b).

Therefore, in cases such as what occurred on December 9, 2012 when SoCalGas and SDG&E were short of supply across their entire system, and there were no supplies available on its Northern System to transport to the Southern System, the Project would not have been able to prevent the occurrence of the event if it had been built at the time.

C. Description of Potential Physical Alternatives to the Proposed Project

The Updated Testimony of SoCalGas/SDG&E witness Bisi states that the Applicants examined three different pipeline projects which are physical infrastructure alternatives to address the Southern System reliability needs with each of the pipeline projects having the capacity to transport 800 MMcfd of supply.[196] The Applicants referred to these pipeline alternatives as (1) River Route; (2) Cross Desert; and (3) North-South Project.[197] These pipeline alternatives are all within the SoCalGas/SDG&E gas transmission system. According to the Applicants, all three pipeline projects would effectively eliminate the Southern System minimum flow requirement.[198] The Applicants eliminated the first two alternatives from further consideration due to their higher estimated cost over the North-South Project.[199] Further, as mentioned in the previous section IV.B. the Applicants contend that the Project has two "significant" advantages over the River Route, that is, the Project would provide Southern System with access to storage and additional receipt points.[200]

Given the deleted project component of the original North-South project (i.e., Moreno-Whitewater pipeline segment), the Applicants were asked to explain whether there are still any physical infrastructure alternatives that were considered

[196] Updated Testimony of David Bisi in A.13-12-013 for SoCalGas/SDG&E dated Nov.12, 2014, pp.7-8.

[197] Bisi, pp.9-15.

[198] Marelli, p.21.

[199] Marelli, p.21.

[200] Marelli, p.21.

by SoCalGas/SDG&E that are comparable to the reduced scope of the project. The Applicants were also asked, if not, whether the previous (1) River Route and (2) Cross Desert options are no longer infrastructure alternatives.

Based on the Applicants response, no other physical infrastructure alternatives were examined by the Applicants following the elimination of the Moreno-Whitewater pipeline component of the North-South Project.[201] This lack of consideration of alternatives is unreasonable.

Three interstate transmission gas pipeline companies have proposed physical alternatives to the North-South Project in this proceeding, namely: (1) El Paso Natural Gas Company (EPNG); (2) Transwestern Interstate Company (TW); and (3) TransCanada/North Baja Company (TC/NB). In addition, there were two intervenor groups, namely, the Southern California Cogeneration Company (SCGC) and The Utility Reform Network (TURN), who recommend only non-physical alternatives but have also included a physical component in their recommendation. Each of these physical alternatives are described below.

1. EPNG Interstate Transmission Proposed Alternative[202]

The El Paso Natural Gas Company, L.L.C. (EPNG) proposes an alternative to the North-South Project. EPNG witness Anthony Sanabria asserts that the updated proposal from SoCalGas/SDG&E on the North-South Project makes EPNG's alternative even more attractive.[203] EPNG represents that their proposed alternative to the North-South Project would provide the same reliable deliveries as the Applicants' Project.[204] According to EPNG, the proposed alternative is scalable and at a lower cost, can be implemented within a shorter timeframe[205], and would have a significantly smaller environmental impact.[206] EPNG explains that through the use of

[201] Response to ORA-NSP-SCG-08 Q.4.

[202] Prepared Updated Testimony of Anthony M. Sanabria in A.13-12-013 for El Paso Natural Gas Company, LLC dated March 23, 2015.

[203] Prepared Updated Intervenor Testimony of Anthony M.Sanabria on behalf of El Paso Natural Gas Company,LLC dated March 23, 2015, p.3.

[204] EPNG, p.3.

[205] As early as 2018.

[206] EPNG, p.3.

capacity acquired on the Mojave Pipeline, it has the ability to accommodate flows from the Topock area on the North Mainline to Ehrenberg by transport of that gas across the Mojave system and then south on the Line 1903 facilities to Ehrenberg.[207] EPNG is also able to receive gas from Kern River Transmission Company (Kern) at Daggett and transport that gas to Ehrenberg.[208] Delivery can be made to the SoCalGas system once the gas physically reaches Ehrenberg, to the North Baja Pipeline or to points further east on EPNG's Southern system.[209] EPNG explains that its system interconnects with Mojave's interstate system and with the systems of SoCalGas and PG&E at Topock, Arizona and another interconnect with the SoCalGas system near Ehrenberg, Arizona.[210]

EPNG provides a comparison of its proposed Alternative against the updated North-South Project in Table 1 of Mr. Sanabria's testimony.[211] At Table 1, the Applicants' Project at 800 Mdth/d capacity is compared against EPNG options 1, 2, and 3, with 300 Mdth/d, 550 Mdth/d, and 800 Mdth/d, respectively. Each EPNG option is shown with lower annual revenue requirements compared to the Applicants' Project. EPNG's Option 3 with 800 Mdth/d is shown in Table 1 with lower annual revenue requirements against the North-South Project. EPNG estimates the forecast savings in annual revenue requirements to be between 38% to 52% depending on the option selected.[212] EPNG's options have terms of 20 years although a longer term is said to be available upon request. In terms of sources of supply, the comparable EPNG option 3 with 800 Mdth/d shows several sources, including EPNG, SoCalGas, maximum 540 Mdth/d via SoCalGas Storage, and Kern.[213] EPNG represents that its annual revenue requirements set forth in

[207] EPNG, pp.3-4.

[208] EPNG, p.4.

[209] EPNG, p.4

[210] EPNG, p.4.

[211] Table 1, EPNG, p.7.

[212] EPNG, p.7.

[213] Table 1, EPNG, p.7.

Mr.Sanabria's testimony shown in Table 1 are fixed and those are firm (subject to approval by appropriate management and other persons of authority of EPNG and/or its parent company).[214]

EPNG explains that the total projected pipeline and compression costs for its proposed alternative to the North-South Project will range from $426.5 million to $486.12 million (in 2014 $).[215] This total projected costs include costs for both the capacity awarded by EPNG in its Feb 19, 2014 open season and capacity that will be used to serve SoCalGas.[216] EPNG states it is willing to accept the financial risk of any increase in project costs and would not seek to increase the annual revenue requirements set forth in Table 1 of Mr.Sanabria's testimony.[217]

In considering the EPNG proposed alternative, ORA uses the information provided by EPNG in testimony and discovery responses.[218]

2. Transwestern Interstate Transmission Proposed Alternative

Transwestern Pipeline Company, LLC (Transwestern) proposes the pipeline project "Needles-Ehrenberg Pipeline" as a superior project alternative to the North-South Project.[219] In testimony, Transwestern witness Steven Hearn explains that Transwestern's mainline pipeline (West of Thoreau) has current capacity of 1,240 MMcf/d and is capable of delivering its full West of Thoreau system capacity to southern California via interconnections with the SoCalGas transmission system at the Needles and Topock receipt points. In addition, according to Transwestern, its pipelines are interconnected also with PG&E's backbone transportation system at Topock and capable of delivering up to 400 MMcf/d at this interconnect.[220]

---

[214] Response to ORA-NSP-EPNG-02 Q3.

[215] Response to ORA-NSP-EPNG-02 Q2.

[216] Response to ORA-NSP-EPNG-02 Q2.

[217] Response to ORA-NSP-EPNG-02 Q3.

[218] In Response to ORA-NSP-EPNG-01 Q1, EPNG objected to providing all workpapers and active excel spreadsheets in support of the EPNG proposed alternative, including but not limited to, those used to arrive at the numbers shown in Tables 1 and 2.

[219] Direct Testimony of Steven Hearn in A.13-12-013 for Transwestern Pipeline Company LLC dated August 15, 2014, p.2.

[220] Transwestern, p.3.

Transwestern explains that the proposed Needles-Ehrenberg pipeline consists of two phases:[221] Phase I consists of approximately 120 miles of new 30-inch diameter pipeline running in a north-south direction in western Arizona while Phase II consists of the addition of 16,000 HP of compression for installation near the pipe's northern interconnect point.[222]

Transwestern expects Phase I pipeline to have a capacity of 500 MMcf/d under an MAOP of 1,300 psig and a designed delivery pressure of 600 psig without the need for any additional compression beyond that already in place on Transwestern's mainline pipeline.[223] Transwestern describes the pipeline route below:[224]

> The Needles-Ehrenberg Pipeline's interconnection with Transwestern's mainline pipeline is at a point located approximately 30 miles east of the Needles delivery point and 8 miles southwest of Kingman, Arizona. From that northern interconnect point, the Phase 1 pipelines runs south through the Arizona desert to the Ehrenberg delivery point, with the option of interconnections along the way to both Questar Southern Trails ("Questar") and El Paso Natural Gas Company, L.L.C. ("EPNG") pipelines.

Transwestern expects that when completed, the Phase II compression will increase the pipeline's capacity by 300 MMcf/d, for a cumulative capacity of 800 MMcf/d.[225]

Based on its vendor and contractor consultations, Transwestern presents preliminary estimates of the direct capital costs of Phase I which amount to a total cost of approximately $418 million and $44 million Phase II.[226] Transwestern states that 5% contingency and 4.5% of inflation are included in its current cost estimate.[227] The estimated annual Operating and Maintenance

---

221 Transwestern, p.5.

222 Transwestern, p.6.

223 Transwestern, p.6.

224 Transwestern, p.5.

225 Transwestern, p.6.

226 Tables 1 and 2, Transwestern, pp.7-8.

227 Response to ORA-NSP-TW-02 Q1 (b-c).

(O&M) costs are approximately $1.1 million.[228] Transwestern clarifies that it would be the party at risk for any unsubscribed capacity.[229]

In terms of timing, the implementation of Phase I of the Transwestern proposed alternative is estimated from 24 to 36 months while Phase II requires from 12 to 16 months.[230]

Transwestern asserts that its proposed alternative is superior to the Applicants' proposed Project in terms of its lower cost, phased construction to better meet actual capacity requirements as these develop, faster in-service date (within 3 years from Transwestern's FERC application for project approval), and use of existing rights-of-way and traversing of sparsely populated areas. Moreover, Transwestern claims that the risk of its initial development costs will be borne by its shareholders rather than the Applicants' ratepayers.[231]

Transwestern estimates the average annual revenue requirement of its proposed alternative would be $75.2 million based on the preliminary cost of Phases I and II.[232] The illustrative revenues and rates for the Transwestern proposed alternative are shown in Table 5 of Mr. Hearn's testimony.[233] The illustrative rate is shown as $0.069/dth/d based on the $75.2 million average annual revenue requirement and a BTS denominator of 2,978 Mdth/d.[234]

In considering the Transwestern proposed alternative, ORA uses the information provided by Transwestern in testimony and discovery responses. ORA does not use any confidential data from Transwestern in its testimony or workpapers.[235]

---

[228] Table 3, Transwestern, p.9.

[229] Response to ORA-TW-02 Q3(h).

[230] Transwestern, pp.9-10.

[231] Transwestern, pp.10-11.

[232] Transwestern, p.11.

[233] Table 5, Transwestern, p.11. Table 5 assumes both Phase I & II were completed concurrently for the first five years of the project.

[234] Transwestern, p.12.

[235] In Response to ORA-NSP-TW-01 Q1, Transwestern provided ORA with workpapers which the company considered competitively sensitive and would provide significant commercial value to

(continued on next page)

3. TransCanada/North Baja Interstate Transmission Proposed Alternative

As an alternative to the Applicants' North-South Project, TransCanada Pipelines Limited (TransCanada) proposes to construct, own, and operate a FERC-jurisdictional natural gas transmission pipeline from the vicinity of Needles to Blythe, California.[236] The TransCanada proposed alternative consists of approximately 90 miles of new 36-inch diameter pipe plus 15 miles of new 24-inch pipeline and potentially one compressor station located near the SoCalGas South Needles Compressor Station.[237] TransCanada describes the pipeline route below:[238]

> The route will extend from an interconnection with SoCalGas near its existing compressor station near Needles ("North Needles Compressor Stattion") located off Highway 95 to an intermediate interconnection with SoCalGas at its South Needles Compressor Station, and then to an existing interconnection between SoCalGas and the North Baja system at Blythe. The route traverses along the western edge of the Rice Valley Wilderness Area north of Blythe and between the Stepladder and Chemehuevi Mountain Wilderderness areas just south of Needles.

TransCanada explains that its proposed pipeline potentially will require the construction of a new compressor station near the SoCalGas South Needles Compressor Station of approximately 16,700 HP.[239] The TransCanada proposed alternative will have a minimum design flow of 300 MMcf/d and a maximum design flow of 800 MMcf/d. [240] The MAOP of TransCanada's proposed alternative will be 1150 psig with a minimum design pressure of 400 psig. According to

(continued from previous page)
competitors if provided, and, therefore, Transwestern provided them pursuant to the Non-Disclosure Agreement executed as of October 14, 2014 between the Office of Ratepayer Advocates and North Baja Pipeline, LLC.

[236] Prepared Direct Testimony of James R. Schoene on behalf of TransCanada Pipelines Limited and North Baja Pipeline, LLC dated August 15, 2014, p.3.

[237] TransCanada, p.3. In its Updated Testimony dated March 23, 2015, TransCanada clarifies that it is not proposing to revise the proposed alternative as described in its August 15 testimony.

[238] TransCanada, pp.3-4.

[239] TransCanada, p.4.

[240] TransCanada, p.4.

TransCanada, the capacity of the proposed alternative can be expanded to up to 1.2 Bcfd with additional compression. [241]

In terms of proposed schedule, TransCanada estimates a construction start date of November 2017 and an in-service date of November 2018 for its proposed alternative to the North-South Project.[242]

TransCanada states that its proposed alternative to the NSP would add the 800 MMcf/d of north to south flow capacity that SoCalGas argues is needed to resolve its minimum flow issues.[243] In addition, TransCanada states that its proposed alternative will increase SoCalGas North Zonal capacity from 1,590 MMcf/d to 1,890 MMcf/d.[244]

In addition to claims of operational advantages, TransCanada asserts that its proposed alternative will be a lower cost option for ratepayers than the Applicants' Project. The preliminary estimate for the current design of the proposed alternative is $585.4 million.[245] The preliminary estimate for the compressor station located near South Needles is $82 million.[246] According to TransCanada, if it is later determined that existing SoCalGas compression can be used to support the TransCanada proposed alternative, then the project costs would be reduced by the $82 million, so that total preliminary cost would be $503.3 million.[247] TransCanada states that it would be at risk for any unsubscribed capacity and that the cost to the ratepayers could further decrease to the extent that other shippers may be interested in taking capacity on the Project.[248] In addition, TransCanada states that it will collect only the Commission-approved rate provided for in its precedent

---

[241] TransCanada, p.4.

[242] TransCanada, p.5.

[243] TransCanada, p.5.

[244] TransCanada, p.5.

[245] TransCanada, p. 7

[246] TransCanada, p.7.

[247] TransCanada, pp.7-8. The cost estimates include a factor for contingency that would range from 20% below the stated estimates and 30% over those estimates.

[248] TransCanada, p.9.

agreement with SoCalGas.[249] According to the TransCanada, its proposed alternative will have fewer environmental and other impacts than the North-South Project.[250]

In considering the TransCanada/North Baja proposed alternative, ORA uses the information provided by the company in testimony and responses.[251]

4. LNG storage in San Diego County Only If Core Would Be at Risk for Curtailment Under Freeze-up Conditions

SCGC's witness Catherine Yap points to the consideration of adding LNG storage in San Diego but **only if** Core customers would be at risk for curtailment under freeze up conditions.[252] This option is not recommended by the SCGC witness, but she simply points out that this option is much less costly than the North-South Project. Ms. Yap estimates that the curtailment level would have to exceed 300 MMcf/d in order to threaten Southern System core loads.[253] According to Ms. Yap, her estimate of the cost associated with installing an LNG storage facility with a 2.0 Bcf inventory and 200 MMcf/d withdrawal rate would be $259 million.[254]

5. Looping Line 6916 to Double Capacity

Similar to the idea of looping of the EPNG Havasu Crossover to connect its North Mainline and South Mainline, the possibility to loop Line 6916 was a suggestion put forward by TURN witness Herbert Emmrich because SoCalGas had said it briefly considered improving Line 6916 as an alternative to the North-South Project.[255]

---

[249] TransCanada, p.10.

[250] TransCanada, p.10-14.

[251] In Response to ORA-NSP-TC-01 Q1, TransCanada provided workpapers in pdf format for information it considered competitively sensitive and that would provide significant commercial value to competitors if provided, and, therefore, TransCanada provided them pursuant to the Non-Disclosure Agreement executed as of October 14, 2014 between the Office of Ratepayer Advocates and North Baja Pipeline, LLC.

[252] Cathy Yap, pp.30-31.

[253] Cathy Yap, p.29.

[254] Cathy Yap, p.30.

[255] Herbert Emmrich, p.3.

SoCalGas previously reported that Line 6916 went into service on December 20, 2012 and that Line 6916 provides a new connection between SoCalGas' Northern Zone and Southern Zone transmission systems.[256] The SoCalGas Report further said that depending upon scheduled supplies, operation of this facility allowed the Southern System minimum flow requirements to be reduced by up to 80 MMcfd.[257]

In a data response to TURN, SoCalGas explains that they have not developed any estimates for the costs to improve Line 6916. According to the Applicants, looping Line 6916 would limit SoCalGas to South Needles supplies, which would not be sufficient to support Southern System loads.[258] Further, the Applicants objected to providing a cost estimate for looping Line 6916 on the grounds that the request was unduly burdensome.[259] This option has no current cost estimate.

D. ORA Recommends that Applicants Use Non-Physical Contractual Alternatives to the Proposed Project

Instead of constructing the Project or any of the other physical alternatives, ORA recommends that Applicants use some combination or all of a host of non-physical alternatives, including contractual ones. These recommended non-physical alternatives are identified as subsections within this section.

In testimony, Applicants state that they have looked at a number of potential non-physical solutions to the "impending" supply-related Southern System cost and reliability problems, but Applicants dismissed these potential non-physical solutions saying, "None of these potential non-physical solutions provide the tools we need."[260]

ORA did not find details of the analysis in their testimony and workpapers, and therefore, requested the Applicants to provide more details regarding the

[256] 4th Annual Forum Report of System Reliability Issues dated April 25, 2013, pp.4-5.

[257] 4th Annual Forum Report, pp.4-5.

[258] Response to TURN DR#6 Q2(a).

[259] Response to TURN DR#6 Q2(b).

[260] Marelli, p.17.

analysis of the potential non-physical solutions. Specifically, ORA asked the Applicants to provide the following:[261]

(a) Identify all the potential non-physical solutions to the impending supply-related Southern System cost and reliability problems "looked at" by Applicants;
(b) Describe the analysis performed by the Applicants in considering or "looking at" each of the identified potential solutions in response to Question 1(a);
(c) Describe the evaluation criteria used by the Applicants to perform the analysis described in response to Question 1(b). If there is a threshold that needs to be met with respect to any of the criteria, then please indicate so;
(d) Provide the results of the analysis and evaluation performed by the Applicants to consider each the non-physical solutions; and
(e) Discuss how the Applicants reached the conclusion that "None of these potential non-physical solutions provide the tools we need."

In Response, the Applicants simply referred to the December 20, 2013 testimony of Ms. Musich (Section VII) and Mr. Bisi (Section VII).[262] The testimony of Ms. Marelli replaced Ms.Musich's testimony.[263] However, Section VII of Ms.Marelli's testimony does not include any quantitative analysis of the non-physical solutions. At best, the referenced Section VII in Ms. Marelli's testimony had only brief narrative explanations (which ORA will later quote in the discussion) of each potential non-physical solution below. Likewise, the referenced Section VII of Mr. Bisi's testimony only had brief narrative explanations and deferred to other witnesses to discuss any price advantages or disadvantages of the non-physical solutions. Mr. Bisi states:[264]

> Such alternatives may have certain price advantages or disadvantages which I will leave to the other witnesses to discuss. From a system design and system operation standpoint, however, any of the infrastructure improvement projects that SoCalGas has proposed in this application are clearly superior to any contractual alternative.

Despite Mr. Bisi's deference to other witnesses, to ORA's knowledge, no other SoCalGas/SDG&E witness presented any discussion of price advantages or

[261] ORA-03 Question 1.

[262] Response to ORA-NSP-SCG-03 Question 1 (a-e).

[263] Updated Testimony of Gwen Marelli (Redlined version).

[264] Bisi, p.18.

disadvantages of the non-physical solutions, and Sempra's claims are unsubstantiated. Applicants bear the burden of proof that its proposal is reasonable, including providing supporting evidence for the arguments it claims support the determination that the Project is reasonable.

Option 1: Continue to Use System Operator Tools Available, Including Some Modifications

To ORA, use of available current S.O. tools, with some modifications, appears to be a reasonable and viable option to address the Southern System supply-related reliability issue. As discussed below, both noncore customers and SoCalGas have demonstrated interest in this non-physical option. As mentioned earlier , the Applicants already have at their disposal a variety of tools to address the Southern System minimum requirement and ensure the system's reliability under conditions of stress in the Southern System. Witness Marelli describes these S.O. tools in Section VI of her testimony regarding efforts to mitigate the Southern System problem.[265] Using these S.O. tools in managing the Southern System problem, the System Operator appears to have achieved relative success to the extent of purchases and sales to secure the Southern System minimum that have kept the occurrence of curtailments of service due to the Southern System reliability issue to a minimum of two so far over the last five years.[266] The first curtailment mentioned was due to supply-related problems outside of California on the El Paso system.[267] The second was due to inadequate quantities of gas being delivered to both the Southern System receipt points and to receipt points serving the rest of the SoCalGas system.[268] There were only 11 instances of curtailment of noncore transportation service over the last five years, including the two previously mentioned, and the other 9 were not even supply-related.[269]

[265] Marelli, pp.12-15.

[266] Response to ORA-NSP-SCG-06 Q.2.

[267] Response to ORA-NSP-SCG-06 Q.2.

[268] Response to ORA-NSP-SCG-06 Q.2.

[269] Response to ORA-NSP-SCG-06 Q3(a).

The Applicants acknowledge that under a status quo, Southern System customers have relatively the same level of reliability as other customers.[270] The Applicants also acknowledge that the reliability enjoyed by Southern System customers can only be attributed to the MILC agreement in place and the purchase and sell at Ehrenberg undertaken by the S.O.[271] The S.O. transactions executed are described in the Annual Compliance Reports submitted to the Commission.[272]

The fact that Applicants have so far been able to point to only two curtailments of service relating to the Southern System supply-related reliability issue[273] indicate that the existing S.O. tools have been successful so far in mitigating Southern System issues. These S.O. tools can be modified to make them more cost effective and tailor-fit to reliability needs in the Southern System. As an example, SoCalGas made a revision to the BTS discounts with no alternate receipt points so that the discounts provide the right incentive to flow gas at the Southern System. Also, the MILC agreements have been subject to some revisions since the initial one was approved in July 2012. In addition, the winter only baseload contracts can be modified to include the summer peak period. SoCalGas had previously mentioned its interest in securing authority to purchase baseload contracts during the summer months in addition to its authority for baseload contracts during the winter months.[274] SoCalGas mentioned this interest during its 2014 Customer Forum held on May 8, 2014 in compliance with Section 21 of Rule No. 41. SoCalGas also commented in the same Forum it was satisfied with the current limits it had on winter baseload purchases, which was 255 Mdth/d.[275]

---

[270] Response to ORA-NSP-SCG-03 Q4(a).

[271] Response to ORA-NSP-SCG-03 Q4(a)

[272] Refer to SoCalGas ALs 4153-A, AL4406, AL 4547, and AL 4690 for the Annual Compliance Reports submitted by SoCalGas pursuant to SoCalGas Rule 41.

[273] Response to ORA-NSP-SCG-06 Q2.

[274] Attachment A to SoCalGas AL 4666, p.4.

[275] Attachment A to SoCalGas AL 4666, p.4.

If a “Do nothing and rely on existing S.O. tools” approach is taken, the Applicants estimate the cost of this option is approximately $32 million.[276] In Table 1 of Ms. Marelli’s testimony, the 4th 12-month period showed total costs of Southern System support in the amount of $20 million. Thus, the $32 million figure would be a conservative one to assume for this option. The current S.O. tools which can be modified to extend for more than one year or longer terms are summarized below:

i. Spot market purchases and sales
ii. RFO Process for Baseload Contracts during the Winter Months
iii. Discounting of Backbone Transportation Service
iv. Movement of Supplies from Blythe to Otay Mesa; and/or
v. MILCs with Gas Acquisition

The existing S.O. tools can be modified/revised to make them more cost effective and tailor fit them to the peak demand periods when the need for the minimum flows on the Southern System are likely highest. In this regard, SCGC witness Cathy Yap suggests adding authority for purchase of baseload contracts for the summer months for noncore’s share of the minimum requirement in addition to the winter months.[277] And as mentioned, the interest to request for this authority was expressed by SoCalGas during the Customer Forum held May 2014. To ORA, this appears both a reasonable and viable option with the common interest from both noncore customers and SoCalGas for this non-physical option to address potential Southern System supply-related issues.

The MILC agreement is already in its third iteration, which includes an evergreening provision for 3 one-year term agreements not to extend beyond a prescribed date in 2016. The end date of the evergreening provision could be extended. SCGC witness Yap also mentioned this non-physical option in order to have longer than one-year MILC agreements.[278]

---

[276] Response to ORA-NSP-SCG-03 Q7(a).

[277] Cathy Yap, pp.14-15.

[278] Cathy Yap, pp.14-15.

Option 2: Continue to Use Line 6916

Line 6916 allows the Southern System minimum requirements to be reduced by up to 80 MMcfd.[279] This option only requires SoCalGas to continue the use of Line 6916 which is already in-service. ORA understands that Line 6916 was factored into the determination of the need for the North-South Project. According to the Applicants, "If Line 6916 were not available, the need for the North-South Project and flowing supplies from Northern receipt points and storage would increase."[280]

The Applicants found that for Line 6916 to be a viable alternative, significant improvement was required in terms of new pipeline and compression. Further, an improved Line 6916 was considered by the Applicants to be more costly than the River Route alternative and that would provide less benefit than that physical alternative.[281] Without the significant improvements on Line 6916, Applicants explain that volumes transported on Line 6916 would be limited to those delivered at the Topock receipt point.[282]

Option 3: Contract for Upstream Supplies[283]

This proposed alternative option would require the Applicants to contract for available firm interstate pipeline capacity to match contracts for basin supplies. Applicants dismiss this alternative saying:[284]

> Even with basin supplies and matching interstate capacity, Southern System customers would be at the mercy of supply-related problems outside of California, just as they are today. Even after substantial expenditures to lock in long-term supplies and interstate transportation, we would essentially be in the same situation we are in today, at least from a reliability standpoint.

[279] Marelli, p.22.

[280] Response to ORA-NSP-SCG-02 Q3.

[281] Response to ORA-NSO-SCG-09 Q.4(a).

[282] Response to TURN DR4 Q2.

[283] Marelli, pp.17-18.

[284] Response to ORA-NSP-SCG-03 Q2(a).

When pressed further to provide the evaluation for this option, Applicants respond that their analysis is similar to that performed by SCGC witness Cathy Yap and explains:[285]

> The analysis we performed was very similar to that performed by Cathy Yap in her August 15, 2014 testimony on behalf of the Southern California Generation Coalition (SCGC), who calculated a cost of $17.5 million/year to hold 255 MMcf/d of long-term El Paso capacity to the Permian basin. This analysis appears roughly correct using forward curves in August of 2014 for the year 2020. But the SoCalGas/SDG&E testimony proposes that 800 MMcf/d of long-term capacity is needed, not 255 MMcfd, which would increase the costs of the SCGC option to $55 million/year (800/255 x $17.5).

SoCalGas argues that it still prefers the infrastructure option over the option offered by the SCGC analysis of contracting for upstream supplies and cites the following reasons:[286]

> First, the cost of the North-South pipeline project is known and fixed, whereas the cost of the SCGC option would change based on market conditions. When SoCalGas did a very similar analysis using forward curves in October 2013 for the year 2018 (the latest publicly available at the time) it estimated a cost of $100 million/year.
>
> Second, both the SoCalGas and SCGC analyses assume current El Paso tariffs as the cost of the interstate capacity. But El Paso's South Mainline is almost fully subscribed; it is uncertain that significant amounts of additional capacity can be subscribed at those rates. Any incremental capacity made available by El Paso could require significant investments on their part and incremental rates that could be higher than those used in both analyses.
>
> Third, assuming the gas the SoCalGas System Operator would be purchasing is re-sold to 3rd parties, the SCGC option requires the SoCalGas System Operator to become the second largest gas purchaser in Southern California, next to its own Gas Acquisition department. Together, these entities would be purchasing almost 2 Bcf/d of gas, or 70% of the Southern California market.

ORA disagrees with the Applicants reasons against contracting for upstream supplies because the most important factor in getting gas to the California border

[285] Response to ORA-NSP-SCG-03 Q2(c).

[286] Response to ORA-NSP-SCG-03 Q2(c).

during periods of either high out-of-state demand or constraints/failures of physical pipelines leading to California is the ability to access firm capacity, rather than secondary supplies that often do not flow at all during tight supply circumstances . SoCalGas has not demonstrated that 800 MMcf/d of intrastate facilities it proposes to build represents the loss of 800 Mmcf/d of current capacity available to the Southern System that future growth will cause to be unavailable, and just because other options provide for a lower amount of incremental capacity does not render such alternatives inferior to the Project. ORA also notes that the Project cost presented in this application is based on a forecast estimate only. Applicants propose to recover the actual Project cost in rates based on actual costs. Hence, the forecast revenue requirements will be trued up upon Project completion to reflect actual costs in revenues required and in rates. Contrary to Applicants assertion the Project cost is known and fixed, the actual Project cost is not known and not fixed at this time. More importantly, as pointed out by SCGC witness Cathy Yap, the proposed size of the SoCalGas Project was determined by SoCalGas based on a higher set of demand criteria different from the Commission's standard design. As a result, the projected need for the Project was inflated by 344 MDth/d above the standard.[287] SoCalGas witness Bisi states the Project uses a 1-in-10 year cold day demand forecast for core customers along with the connected capacity for existing large noncore and electric generation customers.[288]

In addition, Applicants express doubt that additional capacity could be subscribed at those rates citing that El Paso's South Mainline is almost fully subscribed and speculate that these could involve higher incremental rates than those in the analysis.[289] These are mere unsupported speculations. ORA finds that any available capacity on El Paso is made known to interested parties ahead of time on the company's website at http://passportebb.elpaso.com and so there appears to be sufficient time for interested parties to anticipate the availability of

---

[287] Response to SCGC DR#2 Q2.5.

[288] Bisi, p.10.

[289] Response to ORA-NSP-SCG-03 Q2(c).

unsubscribed capacity on the El Paso system. ORA was able to look up postings of unsubscribed capacity with Blythe delivery point location on the El Paso website on April 17, 2015. FERC regulations provide for maximum tariff rates for firm capacity, and Applicants have not demonstrated that the market would be so tight for capacity on El Paso that resold capacity not subject to the maximum rate would exceed the rate.

Option 4: Transfer Southern System Minimum Responsibility Back to Gas Acquisition[290]

The Applicants refer to the option of a return of the responsibility for the Southern System minimum back to Gas Acquisition as an option they had considered but rejected.[291]

Option 5: Supplement or Replace Existing System Operator Tools With Minimum Flowing Supply Requirement for All End-Use Customers

The Applicants cite the option of supplementing or replacing the existing S.O. tools with a minimum flowing supply requirement for all end-use customers as another non-physical alternative they had considered.[292] Applicants explain that SoCalGas' previous Southern System Minimum Flowing Supply Requirement proposal was described in the direct testimony of Rodger Schwecke filed for A.08-02-001 (December 5, 2008), at pp. 17-22.[293] This proposal was withdrawn by SoCalGas pursuant to the 2009 BCAP Phase 1 Settlement adopted by the Commission in D.08-12-020.[294] However, the Applicants believe the cost of this option for a minimum Southern System flow requirement, either for all customers, or just for customers on the Southern System is about the same as the "Do nothing and rely on existing S.O. tools" approach, and the latter option is estimated at

[290] Marelli, p.18 and Updated Testimony of Herbert Emmrich for TURN in A.13-12-013 dated March 23, 2015.

[291] Marelli, p.18.

[292] Marelli, p.19.

[293] Response to ORA-NSP-SCG-03 Q3a.

[294] Response to ORA-NSP-SCG-03 Q3(a).

approximately $32 million.[295] Applicants state that they will consider this option once again but they do not believe the time is ripe for such a proposal.[296] When asked to explain why the time is not ripe for such a proposal now, Applicants respond:[297]

> SoCalGas and SDG&E believe that, customers would not be able to acquire supplies on the Southern System in times of stress like the Southwest Cold Weather Event of February 1-5, 2011 any more readily or easily than the System Operator would. Therefore, SoCalGas and SDG&E do not view a Southern System customer flow order as a viable solution to this problem.

Under this option, the S.O. should be able to at least secure the noncore's share of the minimum flow requirements since the share of the core could be secured by the SoCalGas Gas Acquisition.

Option 6: Purchase LNG Gas from Costa Azul

Another possible non-physical option to address the Southern System reliability issue is to purchase LNG gas from Costa Azul, which would require Commission authorization.[298] The Energia Costa Azul LNG receiving terminal in Baja California is a potential source of gas supply for California but it is currently unutilized because of the current market environment.[299] According to the Applicants, to date, SoCalGas has not transported gas supply on the Bajanorte/TGN systems for delivery at Otay Mesa that was purchased by SoCalGas from the Costa Azul LNG terminal. Applicants cite the need for CPUC authorization before they could purchase gas from Costa Azul and say they have not investigated this option.[300] ORA had requested the Applicants for information regarding the gas volumes scheduled by other shippers for delivery at Otay Mesa. But SoCalGas responded that it was unable to provide the volumes scheduled by other shippers for delivery at Otay Mesa that were transported from the Costa Azul LNG Terminal

---

[295] Response to ORA-NSP-SCG-03 Q7(a).

[296] Marelli, p.20.

[297] Response to ORA-NSP-SCG-09 Q5.

[298] Cathy Yap, pp.29-30.

[299] 2014 California Gas Report, p.10.

[300] Response to SCGC DR2 Q.2.15.

because it does not have access to upstream scheduling data on the Bajanorte/TGN systems that are required to determine the volumes sourced from Costa Azul.[301]

Applicants explain that there are no independent gas storage providers in their service territories. All the underground natural gas storage facilities in southern California are owned and operated by SoCalGas. Applicants state that the Project is the best physical solution to their system since "Storage supplies from providers outside of the SoCalGas and SDG&E service territories would only provide the same level of benefit to our system reliability as delivered pipeline flowing supplies."[302]

Option 7: Provide Sempra with system-wide Low OFO authority in a fashion consistent with ORA's recommendations in that proceeding, as requested in A.14-06-021[303]

The Commission could also grant the Applicants' request for a system-wide Low OFO (Operational Flow Order) as they have asked for in A.14-06-021. This non-physical option was suggested by TURN witness Emmrich.[304] Since this request is being addressed in a separate proceeding before the Commission, ORA will not comment on it here. ORA asked the Applicants about the Low OFO authority as a possible solution for the Southern System supply-related reliabllity issue. The Applicants explained that the Low OFO is not designed to resolve the same issue as the Project.[305] The low OFO is designed to resolve a different problem than the North-South project. According to Applicants, a low OFO/EFO requirement will help bring supplies into their system as a whole during times of system stress, but those requirements can be satisfied by deliveries anywhere on their system or via firm storage withdrawals. This would not enable storage supplies

---

301 Response to ORA-NSP-SCG-02 Q2€.

302 Response to ORA-NSP-SCG-11 Q2.

303 On May 1, 2015, the ALJ in A.14-06-021 issued a proposed decision granting the application of SoCalGas and SDG&E for a low operational flow order and emergency flow order requirements. (See Decision Granting Application of Southern California Gas Company and San Diego Gas & Electric Company for Low Operational Flow Order and Emergency Flow Order Requirements, page 2. If a Decision in the Low OFO proceeding should be finalized before hearings, that decision would supersede ORA's recommendations in the proceeding.

304 Herbert Emmrich, p.2.

305 Response to ORA-NSP-SCG-03 Q7a).

to reach the Southern System, or to provide Southern System customers with access to any additional receipt points.[306]

Option 8: Require Sempra or major electric generating facilities to have emergency alternate fuel capability available for a period of 9-10 days in the form or peak-shaving LNG supplies, propane or jet fuel.

Another non-physical or "no-build" alternative is to require Sempra or major electric generating facilities to have emergency alternate fuel capability available for a period of 9-10 days in the form or peak-shaving LNG supplies, propane or jet fuel.

This appears to be a practical measure suggested by TURN which ORA believes may be reasonable to adopt as an emergency alternate capability.[307] During rare times of extreme demand that constrains the utility's gas transmission system capacity, it is not uncommon to have alternate fuel capability or peak shaving LNG supplies as an emergency capability.

The underlying facts supporting this measure are that: many other non-EG non-core customers do not have alternate fuel backup; these customers have the option to choose core service or firm non-core service; and that either one of these two options would assure natural gas delivery to these customers located in the Southern System.[308] This measure is also premised on the assumption that customers who choose interruptible service can tolerate interruptions or use alternate fuels and therefore receive less reliable service. For SoCalGas/SDG&E or the electric generator facilities on the Southern System, the emergency alternate fuel capability need only be available for a limited period of 9-10 days or less as necessary, to address potential reliability situations in the Southern System. But for those non-EG non-firm customers on the Southern System who provide life-preserving services (such as hospitals), alternate fuel capability on site is a practical non-physical solution to ensure continuity of essential service to their customers.

[306] Response to ORA-NSP-SCG-03 Q7a).

[307] Herbert Emmrich, p.3.

[308] Emmrich, p.13.

Option 9: Have System Operator Hold Firm Capacity Rights to Ehrenberg To Meet Noncore Southern System Minimum Flow

Another possible non-physical option to address the Southern System reliability issue is for the System Operator to hold firm transportation capacity rights to Ehrenberg to meet the noncore Southern System minimum flow.[309] The System Operator can hold capacity for the noncore system reliability to meet the SoCalGas Southern System minimum and purchase gas as needed while the Core Gas Acquisition can do the same for core customers to meet the core's share of the minimum requirement. ORA believes this to be both a reasonable option and a viable one with the suggestion shared by the noncore representatives to address the noncore Southern System minimum flow requirement.

Option 10: Provide EG customers With the Option to Choose Core Service

Another non-physical or "no-build" alternative is to provide Electric Generators with the option to choose Core Service. The cost of this option is unknown since it has neither been considered by the Applicants nor proposed by anyone else. Under current regulation, it is not allowed. But TURN points to this non-physical alternative measure as one that deserves to be studied before authorizing the Applicants' Project.[310] ORA agrees that this option to choose core service would need to be carefully studied. This option is not as simple changing the current regulations to enable the EGs to choose Core Service, or how often the EGs could switch back to Noncore Service once allowed under Core Service. If adopted, Gas Acquisition would need to have enough gas supplies procured, and firm and interruptible capacity on both interstate and intrastate transmission and storage, to be able to take in the incremental EG demand that will be switching to core service. Core customers pay higher rates in exchange for a higher standard of service reliability. The study should determine the amount of incremental capacity to serve the EG demand that has to be acquired by Gas Acquisition. The study also needs to

---

[309] Cathy Yap, pp.16-17.

[310] Herbert Emmrich, p.23.

examine any exit strategy to deal with stranded capacity in the event these EGs find that Noncore Service better serve their interest, and request to switch back.

V. COMPARATIVE ANALYSIS AND DISCUSSION OF RESULTS OF REVIEW

This section provides ORA's analysis and discusses how the various available options compare in terms of cost effectiveness.

A. Detailed Project Cost Analysis and Ratemaking

As outlined elsewhere in this testimony, ORA opposes the North/South Project as unnecessary and overly costly to ratepayers. ORA recommends that the Commission not authorize the project, however should the Commission authorize the North/South Project, ORA recommends a number of specific disallowances relating to excessive project costs as well as changes to the ratemaking proposed by the utilities. It should be noted that by identifying the issues herein, ORA is not conceding that the North/South Project is necessary or that it uniquely benefits ratepayers.

1. Cost Issues

The North/South Project as proposed by the Sempra Utilities is extremely costly relative to other solutions to the reliability concerns expressed in the application. In updated testimony and workpapers the utilities forecast a total capital cost of $621.3 million.[311] This project will substantially impact ratepayers, particularly those at the Backbone Transmission Service level, as well as end-use customers who can already expect to see rate increases relating to ongoing pipeline safety programs, issues relating to the SONGS closure, and Sempra's current rate case.

In testimony filed on November 12, 2014, Sempra reduced the scope of the project by removing the 31 mile Moreno-Whitewater pipeline.[312] The direct cost totals from original and updated testimony are shown in Table 2-5.

[311] Buczkowski, November 2014 Updated Testimony, p. 4 line 7.

[312] Buczkowski, November 2014 Updated Testimony, p. 1.

Table 2-5 - Direct Cost Totals

	Dec-13	Nov-14	% Change
Adelanto-Moreno Pipeline	$331.8	$484.5	46%
Adelanto Compressor Station	$110.7	$136.8	24%
Moreno-Whitewater Pipeline	$186.1	-	-
Total	$628.6	$621.3	-1%

Source: Buczkowski Direct Cost and Schedule Workpapers, December 2013 and November 2014 Update

While the total direct cost decreased in the new forecast by a little more than 1%, the projected total revenue requirement (and thus, cost to ratepayers) has increased by $85 million. Sempra contends that the project will benefit ratepayers proportionately to this substantial sum, an assertion with which ORA disagrees elsewhere herein. Beyond concerns about the benefits of the project as a whole ORA has identified a number of areas where the costs forecast in the Utilities' proposal appear excessive. While the lack of overall detail in Sempra's forecast makes analysis of many of the utilities'' cost forecasts difficult, ORA examines several cost issues in detail below. Applicant's significant increases to forecast costs between initial testimony and the November 2014 update indicates that the initial forecasts were suspect, and that in order to protect ratepayers that overall costs for the project should be capped should the project be approved.

i. Project Costs Should be Capped

Despite removing 1/3 of the pipeline miles from its proposal, Sempra's revenue requirement for the North/South project increased by $85 million between the initial application filing on December 20, 2013 and the filing of Sempra's updated testimony in November 2014. The direct cost for the remaining segments of the Project increased substantially as well. Sempra's cost estimates are poorly substantiated, and it is ORA's opinion that actual revenue requirement on project completion could be much higher that the most recent forecasts. Sempra increased the cost forecast for the Adelanto-Moreno pipeline by 46% between its original application and updated testimony. Forecasts for the Adelanto compressor station increased 24%.

Sempra intends to collect its actual revenue requirement at project completion in rates. Without some sort of project cap the final cost to ratepayers could see substantial further increases. Sempra is seeking an explicit ratepayer backing for any and all cost overruns experienced by the project. This approach is unacceptable for a Project that claims to be more cost-effective than other alternatives without such provisions allowing costs to increase. ORA therefore recommends that should the Commission approve this project over ORA's objections that a cost cap be placed on the amount which Sempra can recover from ratepayers. ORA recommends that this cap be set at a level lower than the amount requested in Sempra's testimony, to reflect a number of disallowances discussed in detail below.

The Commission has previously authorized such cost caps in its 2010 decision authorizing SoCalGas to expand storage capacity at the Honor Rancho storage field,[313] as well as in its 2013 decision authorizing SoCalGas to replace its compression turbines at Aliso Canyon.[314] If the Commission approves the Project, a cost cap would be both appropriate and necessary to protect ratepayers.

ii. Public Relations Capital Disallowance

ORA recommends a substantial disallowance of Sempra's forecast PR expenses. As shown in Table 2-6, Sempra has forecast over $4 million for PR expense relating to the project. Sempra does not speak to the necessity of the expense in testimony.

---

[313] D, 10-04-034, April 22, 2010.

[314] D. 13-11-023, November 14, 2013.

Table 2-6 - Public Relations Expense and Contingencies

	Expense	Contingency %	Total	Difference
Adelanto-Moreno Pipeline - Company Labor	$1,078,125	8%	$1,164,375	$86,250
Adelanto-Moreno Pipeline - Other Capital Costs	$2,425,000	10%	$2,667,500	$242,500
Adelanto Compressor Station - Other Capital Costs	$200,000	15%	$230,000	$30,000
Total	$3,703,125		$4,061,875	$358,750

Source: Buczkowski Direct Cost and Schedule Workpapers, November 2014

Sempra's forecast for PR totals $4,061,875, and constitutes nearly 20% of the project's $21 million total forecasted direct labor costs.[315] It is not clear what benefit there is to ratepayers from having such an expensive PR campaign relating to the project. While there is a legitimate need to communicate with customers and residents in the vicinity of the new pipeline, Sempra's forecast is far out of proportion to this need.

Comparing to similar California utilities puts Sempra's forecast in perspective. In testimony relating to PG&E's 2014 gas transmission and storage rate case, the company states that in 2011 they spent approximately $5 million on a mailing communicating pipeline safety information to every PG&E customer within 2000 feet of PG&E gas transmission lines.[316] PG&E has approximately 6,750 miles of transmission pipeline in California,[317] which amounts to $741 per mile to mail every resident within 2000 feet of PG&E transmission pipe.

In contrast, the North/South pipelines as designed will total about 65 miles. Using the same dollar per pipeline mile measure as above, Sempra's PR forecast equates to about $61,000 per pipeline mile. Nowhere in testimony or workpapers does Sempra indicate why they would need more than 80 times the sum per mile as a similar PG&E PR campaign.

[315] Buczkowski, November 2014 Updated Workpapers, p. WP-2.

[316] ORA DR to PG&E GTS-RateCase2015_DR_ORA_071-Q05.

[317] PG&E 2015 GT&S Rate Case Testimony Volume 1, pg. 1-15, line 4.

ORA recommends capping Sempra's PR forecast at $500,000, which represents a generous sum and plenty for the utility to notify and keep informed residents in proximity to the proposed pipeline. This amounts to nearly $7,700 per pipeline mile, enough to pay for the PG&E mailing used as an example above ten times over. SDG&E and SoCalGas already receive funds for PR through their respective rate cases. Additional ratepayer funding for public relations relating to this project is not necessary and a cost cap is appropriate. This results in a disallowance of $3,203,125.

2. Contingencies

The Sempra Utilities state in testimony that project contingencies "in aggregate, amount to 13.8% of the total direct cost."[318] Sempra gives two examples of other projects for which the CPUC has authorized forecast contingencies, both of which had lower contingencies as a percentage of aggregate costs than the North/South Project.[319] While it is true that the Commission has found contingencies reasonable in the past, a contingency is not a blank check. The contingencies requested by the Sempra utilities make up a significant portion of the project expense forecast. For the reasons given below, ORA recommends a cap for overall contingencies, as well as a number of specific contingency disallowances.

i. Project Contingencies Should be Denied or Capped

One key reason that other physical solutions are less costly is the lack of a ratepayer backing for potential cost overruns. Each of the competing physical and non-physical proposals are meant to provide similar reliability benefits to ratepayers at less cost. Competitive projects have a strong incentive not to exceed forecast project costs precisely because such overruns cannot be recovered from captive ratepayers. In response to an ORA DR on the topic, El Paso explicitly stated that

---

[318] Buczkowski, November 2014 Updated Testimony, p. 14 lines 2-3.

[319] "For example, in D.09-03-026, the Commission authorized PG&E's smart meter Program Upgrade. The approved authorized cost of that project included a risk based allowance (i.e., contingency) of 12.9%. In another example, in D.06-07-027 the Commission authorized PG&E's Advanced Metering Infrastructure project with an 8.0% contingency included in the cost estimate." Buczkowski, November 2014 Updated Testimony, p. 14 lines 15-19.

"Unlike SoCal's North-South Project, EPNG's Annual Revenue Requirements are fixed… EPNG is willing to accept the financial risk of any increase in project costs and would not seek to increase the Annual Revenue Requirements."[320]

If a competitive project experiences cost overruns it is company shareholders who will have to absorb those costs. Because the Sempra Utilities have not made a convincing showing that the North/South Project provides any unique benefits to ratepayers, the Project should be subject to similar contingencies to competing projects. Three other companies have proposed physical solutions which would be significantly less costly for core ratepayers. None of these companies increased the cost of their proposals, as SoCalGas has in its revision, and none of these companies requests that ratepayers fund any cost overruns. Applicants should not be granted any project contingency fees.

In the alternative, ORA recommends capping Sempra's contingency costs at 5%. In response to an ORA DR, TransWestern indicated that its included project contingencies amounted to 5% of project costs.[321] Because there are competing projects and non-physical solutions which could provide the same benefits as the North/South Project, if the Commission were to adopt some level of contingency costs, ORA recommends capping Sempra's contingency costs at 5%. Sempra's project does not provide unique ratepayer benefits and should not have high contingencies serving as an explicit ratepayer backstop for cost overruns.

ii. Contingency Disallowances

While ORA recommends an upper cap for total project contingencies, there are two specific areas where ORA recommends a contingency lower than the 5% cap discussed above. In these two cases, taxes and public relations, the contingencies added to the North/South Project by the Sempra utilities do not appear to be reasonable, and in these cases ORA recommends specific disallowances of those contingency costs.

---

[320] ORA-NSP-EPNG-02, Q. 3.

[321] ORA-NSP-TW-02, Q. 1.

iii. Taxes

In material capital workpapers relating to the Adelanto compressor station, Sempra includes a line item for taxes which includes a 15% contingency.[322] Sempra estimates a tax expense of $5,776,300; with the 15% contingency applied the total is $6,642,745. The difference amounts to nearly a million dollars. Expecting some level of fluctuation in year on year tax expense is reasonable; however a 15% contingency is not. There are two other line items for taxes included in the capital workpapers, and each has a contingency of only 1%. Sempra states that contingencies for the Adelanto Compressor station were set at the project level to total 15% of the direct cost forecast. Using a single contingency rate for the entire project results in a number of unreasonably high contingency line items. In the case of the tax example above this practice adds a million dollars in expense, which Sempra cannot be reasonably expected to incur. ORA recommends disallowance of the 15% contingency for taxes included in the Adelanto compressor station materials forecast, which results in a disallowance of $866,445.

iv. Public Relations

Sempra's capital workpapers contain three line items for Public Relations expenses, and each contains a contingency amount which ORA believes to be seemingly unreasonable. The three line items in question are shown in Table 2.6 above. Sempra is forecasting a public relations campaign out of proportion with the proposed project, and padding those expenses with excessive contingencies. ORA recommends disallowance of all PR related contingencies. Removing these costs results in a further reduction in project expense of $358,500.

3. Ratemaking issues

The utilities have proposed a ratemaking treatment which would "allocate the incremental gas transportation revenue requirements associated with the Project to [Sempra's] Backbone Transportation Service (BTS) rates."[323] Every shipper on Sempra's gas transmission system would see a transportation rate increase

[322] Buczkowski Direct Cost and Schedule Workpapers, November 2014, pg. WP-19.

regardless of whether they make use of or even need the new pipeline infrastructure. The proposed revenue requirement for the North/South project would nearly double the transportation cost on Sempra's system from $0.154 to $0.279 dth/d in 2020.[324] Sempra's proposal is troubling in that violates a core tenet of ratemaking: that of cost causation. The Commission's cost allocation general guidelines focus on the principles of cost causation, economic efficiency, and equity as important considerations in selecting the appropriate allocation factors that are both just and reasonable. It is a long accepted principle that only those who cause the utility to incur the costs and benefit from them should pay for the cost of the service. The benefits North/South may provide to core ratepayers are neither unique nor are they proportional to the significant portion of the proposed BTS rate increase proposed for the core.

i. Core Ratepayers Already Pay for System Stability

The North/South Project's claims to benefit core ratepayers are dubious at best. Despite having filed extensive testimony over multiple revisions, Applicants have not made an adequate showing that the North/South Project provides a benefit to ratepayers that cannot be provided by competing projects or by non-physical means. If Applicants cannot make a convincing showing that the core will benefit in proportion with the costs to core ratepayers then those ratepayers should not bear the cost relating to the project in question.

Applicants make a number of claims about benefits to the core in the form of system stability, but this ignores an important point: the core already pays for system stability. Core ratepayers currently pay for Southern system stability through use of the MILC, a non-physical solution. Core ratepayers pay for long-term firm interstate transportation capacity tied with firm gas supplies, per Commission requirements, to ensure core supply reliability, and such long-term firm capacity combined with storage ensures core reliability. Core ratepayers are being asked to bear costs over

---

(continued from previous page)
[323] Bonnet November 2014 Updated Testimony, p. 1 lines 11-14.

[324] Bonnet November 2014 Updated Testimony, p. 2, Table 1.

and above those already borne for system stability, for a project which has not been proved to offer any unique benefits to core ratepayers. Funding the new pipeline through BTS rates is an unfair windfall for the customers who may make use of and directly benefit from the new pipeline, as core customers would be in effect subsidizing the new pipeline infrastructure. FERC requires interstate pipelines to finance expansions through subscription to the capacity of the expansion by the shippers on the expansion. Applicants have failed to demonstrate that core ratepayers require the Project to provide the same level of reliability than has been historically provided under existing Commission rules.

B. Comparison of the Proposed Project and Alternatives Expressed in terms of Average Annual Revenue Requirements and Determine which are the Least Cost Alternatives

The following Table 2-1 summarizes the average annual revenue requirements associated with each alternative available to address the Applicants' Southern System minimum flow requirements for supply-related reliability needs.

Table 2-1
Illustrative Average Annual Revenue Requirements
Over 20 Years
(In Millions of Dollars)

Existing/ Modified S.O. Tools 300 MMcfd (a)	Contract for Upstream Supplies 456 MMcfd (b)	Contract for Upstream Supplies 800 MMcfd (c)	Min. Flow Req for S.O. or End-Use 300 MMcfd (d)	Applicants' NSP 800 MMcfd (e)	TW 800 MMcfd (f)	EPNG 800 MMcfd (g)	TC** 800 MMcfd (h)
$38.9	$38.9	$66.8	$38.9	$91.7	$75.1	$72.30	$XX.XX

Note: **With compression

The above Table 2-1 indicates that the least cost alternatives in terms of the average annual revenue requirements are anyone of ORA's recommended non-physical alternatives to address the supply-related Southern System reliability issue. The indicative dollar amounts shown in Table 2-1 represent an average of the annual revenue requirements over a 20-year span starting in 2020. The proposed pipeline Project is expected to have a useful life of at least sixty years. The available physical alternatives to the Project have 20-year terms. Even assuming the scenario of intense competition for gas supplies from 2020 through the next 20 years, and further assuming robust US domestic gas production and declining gas exports to Mexico after the year 2040 based on projections by the U.S. EIA and other gas experts discussed in Section IV.A., and assuming the proposed Project is authorized to be built, then there could be potential utility stranded assets in terms of idle pipeline capacity for the North-South Project, whose cost would still be subject to recovery from ratepayers until the year 2096. Over the entire useful life of the Project, the forecast revenue requirements are estimated to be in the amount of $2.782 billion.[325]

C. Comparison of the Proposed Project and Alternatives in terms of Resulting BTS Rate Impacts

Table 2-2
Illustrative Average BTS Rate
Over 20 Years
(In $/dth/d)

Existing/ Modified S.O. Tools 300 MMcfd (a)	Contract for Upstream Supplies 456 MMcfd (b)	Contract for Upstream Supplies 800 MMcfd (c)	Min. Flow Req for S.S. or End-Use 300 MMcfd (d)	Applicants' NSP 800 MMcfd (e)	TW 800 MMcfd (f)	EPNG 800 MMcfd (g)	TC** 800 MMcfd (h)
$0.036	$0.036	$0.063	$0.036	$0.086	$0.070	$0.068	$X.XXX

Note: **With compression

The above Table 2-2 indicates that in terms of the resulting average BTS rates over a 20-year period, ORA's recommended non-physical alternatives result in the lowest cost to address the supply-related Southern System reliability issue. The proposed Project shown in column (e) of Table 2-2 would have an average BTS rate which is more than double the cost of the non-physical alternatives shown. Notably, the proposed Project indicates the highest average BTS rate even compared against

[325] Table 5, Garry Yee Updated Testimony, p.4.

the available physical alternatives to the proposed Project, as shown in columns (f) and (h) of Table 2-2.

On the basis of the incremental BTS rate impact for year 1 when the proposed Project is in service, Table 2-3 shows that the ORA non-physical alternatives would result in the least cost options, as indicated in line 4 of the table at columns (b) through (e). The potential incremental BTS rate increases for the non-physical alternatives range from 19.5% to 33.4%, depending on the amount of capacity deemed to be needed. On the other hand, the proposed Project is shown in column (f) indicating a potential increase of 81.3% over the current BTS SFV tariffs. The potential impact of the incremental BTS rate of the proposed Project would be more than double the impact of the non-physical alternatives. Also, the impact of the incremental BTS rate increases of the proposed Project would be greater than those of the available physical alternatives examined in ORA's review which range from 44% up to no more than 60%.

The impact of the incremental BTS rates at the end-use customer level will not be as significant as those at the backbone transmission level. Since end-use customers do not normally make direct purchases of firm BTS capacity from SoCalGas, the impact of the incremental rates are not quite as significant as evident from Table 2-4, shown in the Summary section of this exhibit.

Table 2-4 compares ORA's and SoCalGas/SDG&E's forecasts of illustrative Bundled rate impacts to end-use customer classes based on ORA's recommended Non-Physical Alternatives against the proposed North-South Project and the available proposed physical alternatives to the Project. At Line 6 of Table 2-4, the percentage impact on residential bundled rates of the non-physical and physical alternatives are shown. At Line 6, Non-physical alternatives would have an impact on the residential bundled rates ranging only from 0.3% to 0.4% while the North-South Project would have an impact of at least 1.1%. The other physical alternatives will impact residential bundled rates to the extent of 0.6% up to no more than 0.9%, which range would still be less than the Project's impact of 1.1%. Tables 2-1 through 2-4 are shown in Section II with the Summary of Recommendations.

Table 2-3
Illustrative Incremental BTS Rate
Year 1 Project In-Service
(in $/Dth/d)

Line No.	Item Description (a)	Rely on Existing/Modified S.O. Tools 300 MMcfd (b)	Contract for Upstream Supplies 456 MMcfd (c)	Contract for Upstream Supplies 800 MMcfd (d)	Min. Flow Req for S.S. or End-Use 300 MMcfd (e)	Applicants' NSP 800 MMcfd (f)	TW 800 MMcfd (g)	EPNG 800 MMcfd (h)	TC** 800 MMcfd (i)
1	Incremental BTS Rate	$0.030	$0.030	$0.052	$0.030	$0.125	$0.071	$0.068	$X.XXX
2	Current BTS SFV Rate	$0.154	$0.154	$0.154	$0.154	$0.154	$0.154	$0.154	$0.154
3	Total BTS SFV	$0.184	$0.184	$0.206	$0.184	$0.279	$0.225	$0.222	$X.XXX
4	Impact in %	19.5%	19.5%	33.4%	19.5%	81.3%	45.8%	44.0%	XX.X%

Note: **With compression

D. Comparison of the Proposed Project and All Alternatives in terms of Avoiding Curtailment under Adverse Weather Events

As discussed in Section IV.B., this exhibit has shown that the proposed Project does not resolve the supply-related Southern System reliability issue. As admitted by the Applicants, the Project could not have prevented the Feb 2011 and 2014 curtailments at the Southern System which were considered supply-related adverse weather events.[326] Nor could the proposed Project have prevented either the January 2013 events[327] or the December 2013 curtailment watch.[328]

This exhibit has also shown that the Project will not eliminate the need for the current S.O. tools under the unlikely event that customers and shippers are not delivering at least 100 MMcfd of supply at Blythe under a high sendout condition.[329]

The proposed Project will only move gas **already** on the system to other parts of the SoCalGas/SDG&E system.[330] Therefore, the proposed Project assumes that there will be gas supplies **already** on the system.

Commission should also note the likelihood of occurrence of adverse weather events. Extreme peak day events in the Applicants' Southern California service territory are defined based on a 1-in-35 likelihood.[331] Freeze-up events such as what occurred on the El Paso system in February 2011 that precipitated the SoCalGas curtailment event are only a 1-in-30 year occurrence.[332] The North-South Project has been shown to be an expensive solution to a rare event that could keep ratepayers on the hook for cost recovery of a pipeline project for years to come.

---

[326] Response to SCGC DR#10 Q.10.1.

[327] Response to SCGC DR#10 Q.10.2

[328] Response to SCGC DR#4 Q.4.16

[329] Response to ORA-NSP-SCG-08 Q3(a).

[330] Response to ORA-NSP-SCG-08 Q.2(b).

[331] 2014 California Gas Report, p.89.

[332] Updated Testimony of Cathy Yap on Behalf of SCGC in A.13-12-013 dated march 23, 2015, p.29.

E. The Results of the Comparative Analysis Supports An Approach Using Non-Physical Alternatives to the Southern System Reliability Issue and Demonstrates that the Proposed North-South Project Is Not the Best Response to the Reliability Issue

For purposes of its analysis of the non-physical option of contracting for upstream supplies, ORA uses the estimated amount calculated by SCGC witness Cathy Yap of $17.5 million a year which the Applicants themselves thought to be a reasonable estimate subject to some adjustment for capacity.[333] The $17.5 million is based on 255 MMcf/d capacity and forward prices in August 2014 for the year 2020. As previously discussed in Section IV.D. of this exhibit, the Applicants' adjustment to the SCGC estimate was made to adjust the $17.5 million for the higher amount of design capacity of the North-South Project of 800 MMcf/d. This adjustment should be reduced by 344 MMcf/d since Applicants admit that the demand criteria they used to arrive at the 800 MMcf/d had over inflated demand by 344.[334] Therefore ORA uses the amount of $32 million for the non-physical option of contracting upstream supplies [i.e.,(800-344)/255 x 17.5] for the year 2020. For the non-physical alternatives, ORA includes an annual escalation of 2 percent for the succeeding years onward. As previously discussed in this exhibit, ORA's analysis shows that the non-physical options are still the most cost effective options compared to the proposed Project and the other proposed physical alternatives to the Project.

As discussed by ORA in Section IV.A., given the indications on outlook for U.S. gas supplies over the years from 2017 through 2040 and in the longer term examined in this exhibit, as well as the long term forecast for a decline in EG demand due to the RPS, an expensive physical solution such as the proposed Project could leave ratepayers with responsibility for cost recovery of stranded idle pipeline assets.

---

[333] Response to ORA-NSP-SCG-03 Q2 (c).

[334] Response to SCGC-02, Q.2.5 cited in Updated Testimony of Cathy Yap for SCGC in A.13-12-013, p.6.

The Applicants propose to pursue a physical infrastructure Project to address a problem that is due to a lack of gas supply. ORA understands that the SoCalGas/SDG&E minimum flow requirement on the Southern System is a function of both flowing supplies and physical infrastructure. As noted in the discussion in Section IV.B.6, SoCalGas represents that it continues to hold adequate backbone transmission capacity and has a reserve margin of backbone capacity consistent with Commission policy.[335] Both flowing supplies and physical infrastructure are necessary to provide reliable service but the Applicants have said that the Southern System reliability issue in this case is due to a lack of gas supply rather than physical infrastructure.[336]

Further, the Applicants admit that the Project will only move gas supply **already** on the SoCalGas/SDG&E system to other parts of the SoCalGas/SDG&E system as it explained:[337]

> The North-South Project will only move gas supply already on the SoCalGas/SDG&E system to other parts of the SoCalGas/SDG&E system. It does not provide a solution to the problem of customers and shippers delivering less gas into the system than they are burning during times of system stress. The North-South Project and our proposed low OFO requirements solve different operational problems.

It bears repeating that if the gas supply is not **already** on the system, then the proposed Project would not provide a solution to less gas being delivered on the system than being burned by customers and shippers. This expensive proposed Project will not resolve the problem of less gas being delivered into the Southern System by its customers. By itself, the North-South Project will not make a difference in periods of stress on the system, since the Project needs the Low OFO to be authorized and in place. On the other hand, as discussed, the various non-physical alternatives detailed in this exhibit could provide a lower cost better solution to this supply-related reliability issue on the Southern System.

---

[335] SoCalGas AL 4662 on Backbone Transmission and Slack capacity.

[336] Response to ORA-NSP-SCG-06 Q1(a).

[337] Response to ORA-NSP-SCG-08 Q2(b).

Alternatively, in the event the Commission sees the need to pursue a physical infrastructure alternative, contrary to all indications discussed herein, to address the SoCalGas Southern System minimum flow requirement supply-related reliability issue, then ORA recommends the Commission order SoCalGas/SDG&E to first reassess the demand criteria used to determine the amount of capacity needed for the pipeline infrastructure, and then either conduct an open solicitation for the physical infrastructure for the capacity shown to be needed, or negotiate with the interested interstate pipeline company who offers the safest and most reliable service at the lowest reasonable cost.

With respect to the ratemaking treatment for a physical infrastructure alternative, ORA recommends the Commission adopt a ratemaking treatment where only those who has need for the physical project for gas supply reliability sign up for the pipeline project and who should pay for it. This is consistent with the principle of cost causation where those who cause the cost should pay for those costs. Otherwise, the ratemaking should be addressed in the next TCAP close to when the pipeline infrastructure will come into service. With non-physical alternatives, ORA recommends allocation of the cost of the non-physical alternatives to manage the Southern System minimum flow requirements to the Backbone Transmission Service (BTS) and the BTS cost shared by all customers of SoCalGas as it is today.[338]

VI. CONCLUSION

Based on the foregoing, ORA respectfully recommends the Commission deny the Applicants' request and instead adopt any of a number of non-physical options available to the Applicants to address the supply-related Southern System minimum flow reliability issue in this proceeding as discussed herein.

[338] Ordering Paragraph #15, D.07-12-019.

VII. WITNESS QUALIFICATIONS

Q1. Please state your name and business address.
A1. My name is Pearlie Sabino. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

Q2. By whom are you employed and in what capacity?
A2. I am employed by the State of California at the California Public Utilities Commission (CPUC) as a Regulatory Analyst in the Office of Ratepayer Advocates (ORA).

Q3. Please describe your educational background and professional experience.
A3. I have an M.A. in Economics from Ateneo de Manila University and a B.S. in Business Economics from the University of the Philippines. As a USAID scholar, I graduated from the Executive Training Program in Energy Planning and Policy of the University of Pennsylvania. Prior to joining the Commission, I worked for 19 years with the largest electric utility in the Philippines in various professional capacities in the areas of economic research, marginal cost studies, project evaluation, corporate budgeting and monitoring, and project financing.

I joined the Commission staff in 1997. In the last 17 years, I have worked on a number of electric and natural gas matters including but not limited to the following: the review of SoCalGas' Gas Cost Incentive Mechanism; the review of Biennial Cost Allocation Proceeding (BCAP) applications for PG&E, SoCalGas and SDG&E; various gas transportation contracts (such as Guardian, Ruby, US Gypsum), various applications pertaining to the grant of Certificate of Public Convenience and Necessity (CPCN) for gas storage contracts, including amendments; SoCalGas/SDG&E system integration and firm access rights proceedings, including the FAR Update proceeding, the Joint SCE/SoCalGas/SDG&E Omnibus proceeding, the Joint PG&E/SoCalGas/SDG&E Application for Public Purpose Program Cost Reallocation proceeding, the PG&E Gas Transmission & Storage rate cases in A.13-12-012 and A.09-09-013 (Gas Accord V Settlement), the PG&E Pipeline Safety Enhancement Plan Phase 1 in R.11-02-019 and San Bruno Investigation cases, the SoCalGas/SDG&E Pipeline Safety Enhancement Plan in A.11-11-002 Phase 1 &2, and the Southwest Gas 2014 GRC in A.12-12-024.

Q4. What is your area of responsibility in this proceeding?

A4. I am responsible for Exhibit ORA-02 which addresses the economic analysis and comparisons with respect to the request of Southern California Gas Company and San Diego & Electric Company Application for authority to recover North-South Project revenue requirements in customer rates and related cost allocation and rate design proposals in A.13-12-013.

Q5. Does that complete your prepared testimony?

A5.Yes, it does.