Attachment A

Pipeline Segment Attributes Using the Barlow Equation

PUBLIC VERSION

Attachment A - Pipeline Segment Attributes Using the Barlow Equation

Confidential information provided pursuant to General Order 66-C, California Public Utilities Code Section 583, and D.16-08-024. Accordingly, a declaration is included with this Attachment.

A	B	C	D	E	F	G	H	I	J	K	L	M
	CONFIDENTIAL	CONFIDENTIAL		CONFIDENTIAL			CONFIDENTIAL	CONFIDENTIAL	CONFIDENTIAL		CONFIDENTIAL	CONFIDENTIAL
												Formula: **PSIG/((2 X SMYS – psi X Wall Thickness-inches)/ Outside Diameter-inches) X 100** **320/((2 X Column I X Column H)/ Column G) X 100**
Pipeline	BEGENGSTA	ENDENGSTA	DOTCLASS	DESIGN FACTOR	NOTES	OD (in.)	WT (in.)	SMYS (psi)	INSTALLDATE	MAOP (psig)	%SMYS @ 640 psig	%SMYS @ 320 psig
1600	[redacted]	[redacted]	Class 3	[redacted]		16	[redacted]	[redacted]	[redacted]	640	[redacted]	[redacted]
1600	[redacted]	[redacted]	Class 3	[redacted]		16	[redacted]	[redacted]	[redacted]	640	[redacted]	[redacted]
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1600	[redacted]	[redacted]	Class 1	[redacted]		16	[redacted]	[redacted]	[redacted]	640	[redacted]	[redacted]

Pipeline	BEGENGSTA	ENDENGSTA	DOTCLASS	DESIGN FACTOR	NOTES	OD (in.)	WT (in.)	SMYS (psi)	INSTALLDATE	MAOP (psig)	%SMYS @ 640 psig	%SMYS @ 320 psig
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1600	[redacted]	[redacted]	Class 2	[redacted]		16	[redacted]	[redacted]	[redacted]	640	[redacted]	[redacted]
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Pipeline	BEGENGSTA	ENDENGSTA	DOTCLASS	DESIGN FACTOR	NOTES	OD (in.)	WT (in.)	SMYS (psi)	INSTALLDATE	MAOP (psig)	%SMYS @ 640 psig	%SMYS @ 320 psig
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*Class Location changed within the segment

Attachment B

Utilities' Responses to ORA Data Requests

Attachment B-1

Second Amended Response to ORA DR-06, Q12
(May 22, 2017)

PUBLIC VERSION

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-06)

Date Requested: April 27, 2016
Date Responded: May 12, 2016
Amended Response Submitted: April 27, 2017
Second Amended Response Submitted: May 22, 2017

PRELIMINARY STATEMENT

1. These responses and objections are made without prejudice to, and are not a waiver of, SDG&E and SoCalGas' right to rely on other facts or documents in these proceedings.
2. By making the accompanying responses and objections to these requests for data, SDG&E and SoCalGas does not waive, and hereby expressly reserves, its right to assert any and all objections as to the admissibility of such responses into evidence in this action, or in any other proceedings, on any and all grounds including, but not limited to, competency, relevancy, materiality, and privilege. Further, SDG&E and SoCalGas makes the responses and objections herein without in any way implying that it considers the requests, and responses to the requests, to be relevant or material to the subject matter of this action.
3. SDG&E and SoCalGas will produce responses only to the extent that such response is based upon personal knowledge or documents in the possession, custody, or control of SDG&E and SoCalGas. SDG&E and SoCalGas possession, custody, or control does not include any constructive possession that may be conferred by SDG&E or SoCalGas' right or power to compel the production of documents or information from third parties or to request their production from other divisions of the Commission.
4. A response stating an objection shall not be deemed or construed that there are, in fact, responsive information or documents which may be applicable to the data request, or that SDG&E and SoCalGas acquiesces in the characterization of the premise, conduct or activities contained in the data request, or definitions and/or instructions applicable to the data request.
5. SDG&E and SoCalGas objects to the production of documents or information protected by the attorney-client communication privilege or the attorney work product doctrine.
6. SDG&E and SoCalGas expressly reserve the right to supplement, clarify, revise, or correct any or all of the responses and objections herein, and to assert additional objections or privileges, in one or more subsequent supplemental response(s).
7. SDG&E and SoCalGas will make available for inspection at their offices any responsive documents. Alternatively, SDG&E and SoCalGas will produce copies of the documents. SDG&E and SoCalGas will Bates-number such documents only if SDG&E and SoCalGas deem it necessary to ensure proper identification of the source of such documents.
8. Publicly available information and documents including, but not limited to, newspaper clippings, court papers, and materials available on the Internet, will not be produced.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-06)

Date Requested: April 27, 2016
Date Responded: May 12, 2016
Amended Response Submitted: April 27, 2017
Second Amended Response Submitted: May 22, 2017

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9. SDG&E and SoCalGas object to any assertion that the data requests are continuing in nature and will respond only upon the information and documents available after a reasonably diligent search on the date of its responses. However, SDG&E and SoCalGas will supplement its answers to include information acquired after serving its responses to the Data Requests if it obtains information upon the basis of which it learns that its response was incorrect or incomplete when made.
10. In accordance with the CPUC's Discovery: Custom And Practice Guidelines, SDG&E and SoCalGas will endeavor to respond to ORA's data requests by the identified response date or within 10 business days. If it cannot do so, it will so inform ORA.
11. SDG&E and SoCalGas object to any ORA contact of SDG&E and SoCalGas officers or employees, who are represented by counsel. ORA may seek to contact such persons only through counsel.
12. SDG&E and SoCalGas objects to ORA's instruction to send copies of responses to entities other than ORA.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-06)

Date Requested: April 27, 2016
Date Responded: May 12, 2016
Amended Response Submitted: April 27, 2017
Second Amended Response Submitted: May 22, 2017

This second corrected and amended response replaces the response to ORA DR-06, Question 12 submitted on May 12, 2016 and the amended response submitted on April 27, 2017 in its entirety.

QUESTION 12:

For Line 1600, provide records for the specific items (i.e. wall thickness) needed to complete the design pressure equation under 49 Code of Federal Regulations § 192.105.

RESPONSE 12:

This response contains confidential information (shaded in gray); additionally, the attachment submitted along with this response contains confidential information provided pursuant to California Public Utilities Code § 583, General Order 66-C and D.16-08-024. Accordingly, a confidentiality declaration is included with the attachment.

As ORA was informed in Applicants' November 30, 2016 response to ORA DR 51, Question 3, the Line 1600 segment for Engineering Station 17-131 was replaced as of October 26, 2016. The Second Corrected and Updated Attachment to this response reflects such replacement.

The May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data attached to this response also reflects corrections of inaccurate information provided in the original May 12, 2016 Attachment. The original data was taken from a database that had not been fully updated to reflect information learned from research of historical records and to reflect recent construction activity. The corrected information was previously provided to ORA in: (1) Applicants' August 12, 2016 response to ORA DR 25, Question 1; (2) Applicants' August 4, 2016 email to ORA (Ogeonye Enyinwa, Nathaniel Skinner, Mina Botros, Pearlie Sabino, and Darryl Gruen) attaching an amendment to a document previously provided in response to ORA DR 19, specifically a copy of Applicants' August 2, 2016 amended response to SED DR 3, Q2 and Attachment thereto; and (3) Applicants' July 15, 2016 response to ORA DR 19 (which provided a copy of Applicants' original response to SED DR 3, Q2 and Attachment thereto). Corrections are noted in red in the attachment.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-06)

Date Requested: April 27, 2016
Date Responded: May 12, 2016
Amended Response Submitted: April 27, 2017
Second Amended Response Submitted: May 22, 2017

In preparing Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data, Applicants confused the Cumulative (CUM) Stationing used in the response to ORA-DR06, Q12 for the Engineering (ENG) Stationing used in the response to ORA-DR25, Q1 and Q2. This resulted in an error with respect to the wall thickness for CUM Station [redacted] to [redacted] (ENG Station [redacted] to [redacted]), which should be [redacted] inches rather than [redacted] inches, and an error for CUM Station [redacted] to [redacted] (ENG Station [redacted] to [redacted]), which should be [redacted] inches rather than [redacted] inches. A further explanation of CUM and ENG Stationing is provided in Applicants' response to ORA DR-84, Q1. Those errors are corrected in the May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data attached to this response.

The May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data attached to this response provides the records required to complete the design pressure equation.

All Line 1600 pipe segments are designed in accordance with the PHMSA 192.105 Design Formula:
P = (2St/D) x F x E x T

F = [redacted], Factor for Class 3 location
E = [redacted], Longitudinal Joint Factor
T = [redacted], Temperature factor for 250 degrees Fahrenheit or less

All Line 1600 pipe segments are less than 20% SMYS at [redacted] psig
% SMYS = (PD/2t)/Yield Strength) x (100)

P = [redacted] psig pipeline pressure
D = [redacted] inches
t = wall thickness, inches
Specified Minimum Yield Strength, psi

Attachment B-2

Utilities' Response to ORA DR-19, Q6 (July 15, 2016), &
Attached Response to SED DR-03, Q2 and Q3

PUBLIC VERSION

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-19)

Date Requested: June 30, 2016
Date Responded: July 15, 2016

QUESTION 6:

Please provide any and all past and present data responses from SDG&E, SoCalGas, Sempra, and Sempra affiliates to Commission staff and all other parties. Include the data requests that prompted each data response. This request covers any data requests and responses since SDG&E/SoCalGas prepared their response to ORA DR-05 that are not posted on the SDG&E/SoCalGas website.

RESPONSE 6:

SDG&E and SoCalGas object to this request as vague and ambiguous, and thus potentially overbroad and unduly burdensome. SDG&E and SoCalGas interpret this request as calling for data request responses in this proceeding. SDG&E and SoCalGas further object to this request insofar as it calls for the production of documents which are publicly available or otherwise equally accessible to ORA and on the grounds that it is unduly burdensome.

SDG&E and SoCalGas object to this request to the extent the request purports to impose any requirement or discovery obligation greater than or different from those under the California Public Utilities Commission ("Commission or CPUC") Rules of Practice and Procedure, Statutes, and the applicable Orders of the Commission. SDG&E and SoCalGas will produce responses only to the extent that such response is based upon personal knowledge or documents in the possession, custody, or control of SDG&E and/or SoCalGas, as set forth in the CPUC Rules of Practice and Procedure. SDG&E's and SoCalGas' possession, custody, or control does not include any constructive possession that may be conferred by SDG&E's and SoCalGas' right or power to compel the production of documents or information from third parties or to request their production from other divisions of the Commission. Specifically, SDG&E and SoCalGas object to providing Sempra and Sempra affiliate data responses due to affiliate compliance rules. Without waiving this objection, and subject thereto, SDG&E and SoCalGas respond as follows:

SDG&E and SoCalGas are not the makers of the Sempra and Sempra affiliates data responses in this proceeding. Sempra Energy, based in San Diego, is a Fortune 500 energy services holding company. Sempra Energy's California regulated utilities, SDG&E and SoCalGas, are separate legal entities with detached accountability.

Data responses to intervening parties in this proceeding are posted on SDG&E's and SoCalGas' respective webpages.

http://www.sdge.com/regulatory-filing/15786/pipeline-safety-reliability-project
https://www.socalgas.com/regulatory/A15-09-013.shtml

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-19)

Date Requested: June 30, 2016
Date Responded: July 15, 2016

Please refer to ORA DR 5 for copies of data responses sent to SED, Sierra Club, TURN, and UCAN. Data responses provided since that submittal, with attachments or confidential data provided as of July 14, 2016 will be sent via Electronic Data Transfer due to size. For future data requests, please provide references to specific data responses that you are requesting. Please note that some of the information provided contains confidential information provided pursuant to Cal. Pub. Util. Code § 583 and G.O. 66-C.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(SED DATA REQUEST- 3)

Date Requested: May 31, 2016
Date Responded: June 13, 2016

QUESTION 2:

A segment by segment engineering analysis for the entire Line 1600 with any unknown pipeline characteristics identified and any assumed values detailed.

RESPONSE 2:

Some of the information provided in the attachment contains confidential information provided pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583.

As part of the Maximum Allowable Operating Pressure (MAOP) validation process each segment was analyzed to determine the appropriate MAOP based on year of installation, pipe properties, class location, test records and historical operating pressures. The segment in the attached document (SED DR 3 Q2 and Q3 L1600 SEGMENTS.pdf) highlighted in gray has an unknown wall thickness and grade and the corresponding engineered value is prefixed with a “DT” (Decision Tree) designation. In addition as described in Question 1 above, an assessment and remediation of Line 1600 has been completed using In-Line-Inspection (MFL, TFI, Caliper) and External Corrosion Direct Assessment and deemed fit for service.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(SED DATA REQUEST- 3)

Date Requested: May 31, 2016
Date Responded: June 13, 2016

QUESTION 3:

Provide a detailed analysis of all segments that have been pressure tested, with traceable, verifiable, and complete test records.

RESPONSE 3:

SDG&E and SoCalGas interpret "traceable, verifiable and complete" to mean "reliable and accurate" and respond as follows:

See response to Question 2, above. Some of the information provided in the attachment contains confidential information provided pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583.

As mentioned in SED DR 2, there are still some projects being entered into the database and once added this response will be updated.

Attachment B-3

August 4, 2016 Email to ORA & Attached Amended Response to SED DR-03

PUBLIC VERSION

[redacted]

From: Amrany, Shirley
Sent: Thursday, August 4, 2016 7:56 PM
To: 'Enyinwa, Ogeonye'; 'Skinner, Nathaniel'; 'Gruen, Darryl'; 'Sabino, Pearlie Z.'; 'Botros, Mina'
Cc: Raagas, Kirstie; Pacheco, John A.; 'Richard@[redacted] Trial, Allen
Subject: RE: ORA DR-19 in A.15-09-013
Attachments: SED_DR_3 Amended Q2.pdf; Confidential SED DR 3 Q2 L1600 SEGMENTS_Revised.pdf

Oge,

Enclosed is an amended attachment that was provided in response to ORA DR 19 (copy of data request for SED DR 3). SDG&E and SoCalGas discovered an error in the MAOP calculator it utilized to produce the report in SED DR 3 Q2 and resubmitted the attachment to SED this week. The error was limited to the design pressure 192.619(A1) calculation and has been corrected. The pipe segment records highlighted in light green have been updated. Please note the attachment contains confidential information that is submitted pursuant to Cal. Pub. Util. Code § 583 and G.O. 66-C

Best Regards,
Shirley Amrany

Regulatory Affairs - SoCalGas
[redacted]

From: Amrany, Shirley
Sent: Friday, July 15, 2016 4:45 PM
To: 'Enyinwa, Ogeonye'; Skinner, Nathaniel
Cc: Gruen, Darryl; Sabino, Pearlie Z.; Botros, Mina; Raagas, Kirstie; Pacheco, John A.; 'Richard@[redacted]Trial, Allen
Subject: RE: ORA DR-19 in A.15-09-013

Oge,
Attached is SDG&E and SoCalGas' response to ORA DR 19. Due to the file size, the attachments will be sent via electronic data transfer. Please note that some of the attachments contain confidential information that is submitted pursuant to Cal. Pub. Util. Code § 583 and G.O. 66-C.

Regards,
Shirley Amrany

Regulatory Affairs - SoCalGas
[redacted]

From: Enyinwa, Ogeonye [mailto:[redacted]
Sent: Thursday, June 30, 2016 8:06 PM
To: Trial, Allen; 'Richard@[redacted] Hovsepian, Melissa A; Amrany, Shirley
Cc: Gruen, Darryl; Sabino, Pearlie Z.; Botros, Mina; Skinner, Nathaniel
Subject: ORA DR-19 in A.15-09-013

Hello Shirley,
See attached is ORA's DR-19 in the Application for a CPCN for the Line 1600 project.
Please let Pearlie, Darryl Gruen, or Nat know if you have any questions.

Thank you.

Oge Enyinwa
Utilities Engineer
Energy Safety & Infrastructure Branch, Office of Ratepayer Advocates
California Public Utilities Commission
[redacted]

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(SED DATA REQUEST- 3 Amended)

Date Requested: May 31, 2016
Date Responded: June 13, 2016
Amended Response: August 2, 2016

QUESTION 2:

A segment by segment engineering analysis for the entire Line 1600 with any unknown pipeline characteristics identified and any assumed values detailed.

RESPONSE 2:

Some of the information provided in the attachment contains confidential information provided pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583.

As part of the Maximum Allowable Operating Pressure (MAOP) validation process each segment was analyzed to determine the appropriate MAOP based on year of installation, pipe properties, class location, test records and historical operating pressures. The segment in the attached document (*Confidential SED DR 3 Q2 L1600 SEGMENTS_revised.pdf*) highlighted in gray has an unknown wall thickness and grade and the corresponding engineered value is prefixed with a “DT” (Decision Tree) designation. In addition as described in Question 1 above, an assessment and remediation of Line 1600 has been completed using In-Line-Inspection (MFL, TFI, Caliper) and External Corrosion Direct Assessment and deemed fit for service.

Attachment B-4

Utilities' Response to ORA DR-25, Q1 and Q5 and
Amended Response to ORA DR-25, Q1

PUBLIC VERSION

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-25)

Date Requested: July 29, 2016
Date Responded: August 12, 2016

QUESTION 1:

Please provide an updated version of the table provided in response to SED DR-3, Q2 and Q3, that includes the following columns appended to the end:

a. Longitudinal Joint Factor

b. If the Joint is Known (K) or Unknown (U)

c. The year of each class location change (blank if no class location change)

d. The class location prior to each change

e. The class location after each change

Provide the response as an active Excel spreadsheet. If an entry has more than one class location change, append an additional set of items c-e to the end of the entry. Please highlight each column that contains information that SoCalGas/SDG&E claims to be confidential.

RESPONSE 1:

Some of the information provided in the attachment contains confidential information provided pursuant to G.O 66-C and Cal. Pub. Util. Code § 583.

The attached excel file appends the requested additional columns. Please note that the attachment also reflects the updates provided to ORA on August 4, 2016.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-25)

Date Requested: July 29, 2016
Date Responded: August 12, 2016

QUESTION 5:

CONTAINS DATA IDENTIFIED AS CONFIDENTIAL BY SCG/SDG&E

On line 5 of the table provided to SED DR-3, Q2 and Q3, SoCalGas/SDG&E give a series of values. Please explain why the 192619(A1) value is 650, given the response to ORA DR-6, Q12, where SoCalGas/SDG&E stated the longitudinal joint factor is 1.0.

RESPONSE 5:

Please see response to Question 1 above.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-25)

Date Requested: July 29, 2016
Date Responded: August 12, 2016
Amended Response Submitted: April 27, 2017

The response to Question 1 has been amended, changes are noted in **red, bold and underline**.

QUESTION 1:

Please provide an updated version of the table provided in response to SED DR-3, Q2 and Q3, that includes the following columns appended to the end:

a. Longitudinal Joint Factor

b. If the Joint is Known (K) or Unknown (U)

c. The year of each class location change (blank if no class location change)

d. The class location prior to each change

e. The class location after each change

Provide the response as an active Excel spreadsheet. If an entry has more than one class location change, append an additional set of items c-e to the end of the entry. Please highlight each column that contains information that SoCalGas/SDG&E claims to be confidential.

RESPONSE 1:

Some of the information provided in the attachment contains confidential information provided pursuant to G.O 66-C and Cal. Pub. Util. Code § 583 **and D.16-08-024. Accordingly, a confidentiality declaration is included with the attachment.**

The attached excel file appends the requested additional columns. Please note that the attachment also reflects the updates provided to ORA on August 4, 2016.

The updates to the table in the Corrected and Updated Attachment are noted in red and reflect the replacement of a segment in October 2016 per Resolution SED-1.

Attachment B-5

Utilities' Response to ORA DR-84

PUBLIC VERSION

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

PRELIMINARY STATEMENT

1. These responses and objections are made without prejudice to, and are not a waiver of, SDG&E and SoCalGas' right to rely on other facts or documents in these proceedings.
2. By making the accompanying responses and objections to these requests for data, SDG&E and SoCalGas does not waive, and hereby expressly reserves, its right to assert any and all objections as to the admissibility of such responses into evidence in this action, or in any other proceedings, on any and all grounds including, but not limited to, competency, relevancy, materiality, and privilege. Further, SDG&E and SoCalGas makes the responses and objections herein without in any way implying that it considers the requests, and responses to the requests, to be relevant or material to the subject matter of this action.
3. SDG&E and SoCalGas will produce responses only to the extent that such response is based upon personal knowledge or documents in the possession, custody, or control of SDG&E and SoCalGas. SDG&E and SoCalGas possession, custody, or control does not include any constructive possession that may be conferred by SDG&E or SoCalGas' right or power to compel the production of documents or information from third parties or to request their production from other divisions of the Commission.
4. A response stating an objection shall not be deemed or construed that there are, in fact, responsive information or documents which may be applicable to the data request, or that SDG&E and SoCalGas acquiesces in the characterization of the premise, conduct or activities contained in the data request, or definitions and/or instructions applicable to the data request.
5. SDG&E and SoCalGas objects to the production of documents or information protected by the attorney-client communication privilege or the attorney work product doctrine.
6. SDG&E and SoCalGas expressly reserve the right to supplement, clarify, revise, or correct any or all of the responses and objections herein, and to assert additional objections or privileges, in one or more subsequent supplemental response(s).
7. SDG&E and SoCalGas will make available for inspection at their offices any responsive documents. Alternatively, SDG&E and SoCalGas will produce copies of the documents. SDG&E and SoCalGas will Bates-number such documents only if SDG&E and SoCalGas deem it necessary to ensure proper identification of the source of such documents.
8. Publicly available information and documents including, but not limited to, newspaper clippings, court papers, and materials available on the Internet, will not be produced.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

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9. SDG&E and SoCalGas object to any assertion that the data requests are continuing in nature and will respond only upon the information and documents available after a reasonably diligent search on the date of its responses. However, SDG&E and SoCalGas will supplement its answers to include information acquired after serving its responses to the Data Requests if it obtains information upon the basis of which it learns that its response was incorrect or incomplete when made.
10. In accordance with the CPUC's Discovery: Custom And Practice Guidelines, SDG&E and SoCalGas will endeavor to respond to ORA's data requests by the identified response date or within 10 business days. If it cannot do so, it will so inform ORA.
11. SDG&E and SoCalGas object to any ORA contact of SDG&E and SoCalGas officers or employees, who are represented by counsel. ORA may seek to contact such persons only through counsel.
12. SDG&E and SoCalGas objects to ORA's instruction to send copies of responses to entities other than ORA.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

For Questions 1 through 19, ORA has noted inconsistent data sets regarding certain attributes along Line 1600. The primary questions use the shortest engineering station segments on Line 1600, taken from the original and updated responses to ORA DR-06, Q12, in an attempt to clarify these discrepancies.

<u>QUESTION 1:</u>

For engineering stations [redacted] to [redacted]:

a. Provide all supporting information for the original May 2016 response to ORA DR-06, Q12 that supported a wall thickness of [redacted] inches for engineering stations [redacted] to [redacted].

b. Provide all supporting information for the April 2017 updated response to ORA DR-06, Q12 that supports a wall thickness of [redacted] inches for engineering stations [redacted] to [redacted].

c. Confirm that the April 2017 update to ORA DR-25, Q1 identifies engineering stations [redacted] to [redacted] as having a wall thickness of [redacted] inches.

d. Confirm that the April 2017 update to ORA DR-25, Q1 identifies engineering stations [redacted] to [redacted] as having a wall thickness of [redacted] inches.

e. Provide all supporting information for the April 2017 update to ORA DR-25, Q1 supporting the wall thicknesses of [redacted] and [redacted] inches.

f. Explain why SoCalGas/SDG&E has provided inconsistent responses within ORA DR-25, Q1 as to the wall thickness of Line 1600 between engineering stations [redacted] and [redacted].

g. Please explain why SoCalGas/SDG&E provided inconsistent responses between ORA DR-06, Q12 and ORA DR-25, Q1 for engineering stations [redacted] to [redacted].

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

RESPONSE 1:

Cumulative Stationing vs. Engineering Stationing

The question and response (and accompanying attachments) contains confidential information (shaded in gray) and is provided pursuant to Cal. Pub. Util. Code § 583, G.O. 66-C, D.16-08-024 and the accompanying declaration. Question 1 refers to "engineering stations [redacted] to [redacted]" in questions regarding both Applicants' response to ORA DR-06, Q12 and Applicants' response to ORA DR-25, Q1. Applicants clarify that the attachment to Applicants' response to ORA DR-06, Q12, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data, refers to "cumulative stations," not "engineering stations." By contrast, the attachment to Applicants' response to ORA DR-25, Q1, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR-25, Q1, refers to "engineering stations," not "cumulative stations."

Although the stationing values are in close proximity to each other, the minor differences create an incorrect comparison of pipeline segments. Cumulative stationing is a direct measurement down the centerline of the pipeline and is re-calculated each time the pipeline is modified; therefore, each reiteration of the pipe will have a new cumulative stationing value. In contrast, "engineering station" values are memorialized on the pipeline and do not change even though the geometry of the pipeline changes. The benefit of "engineering stationing" is that attribute information can easily be associated to legacy drawings. One downside of using engineering stationing values is that the true length of the pipeline is not easily calculated due to the introduction of station equations. When a section of pipeline is modified, a station equation is added to represent a location where the stationing and design has changed. The equation is represented with an "Ahead" and "Back" engineering station value that compensates for the modified pipeline length and allows the engineering stationing to be preserved upstream and downstream of the tie-in point. An explanation of how Applicants use a "stationing equation" is attached here to as *StationEquationExample_Attachment.pdf*.

Each time modifications are made to Applicants High Pressure Database to reflect work on a pipeline, such as relocations or removals, the Cumulative Stationing may change. For purposes of this Data Request, which is asking about Cumulative Stationing of Line 1600 segments that existed in the High Pressure Database in May 2016, Applicants have responded regarding the segments represented by the Cumulative Stationing for those segments as it existed at that time. As the High Pressure Database is updated, the Cumulative Stationing of those segments may change, though the Engineering Stationing will not. If requested, Applicants are willing to provide an updated table of Line 1600 segment data reflecting Cumulative Stationing, but will not otherwise update Cumulative Stationing information. Given that ORA is seeking

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

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Date Requested: May 5, 2017
Date Responded: May 22, 2017

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documentation of the pipeline values, Line 1600 segment data based on Engineering Stationing would appear more useful.

With respect to the pipeline segment that is the focus of Question 1, the "cumulative station" ("CUM Station") [redacted] to [redacted] (reflected in the response to ORA-DR06, Q12) is the same as "engineering station" ("ENG Station") [redacted] to [redacted] (reflected in the response to ORA-DR25, Q1). Applicants provide similar comparison information for the Line 1600 segments that are the subject of Questions 2 through 6.

In preparing Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data, Applicants confused the CUM Stationing used in the response to ORA-DR06, Q12 for the ENG Stationing used in the response to ORA-DR25, Q1. This resulted in errors with respect to the wall thickness for two segments (the actual wall thicknesses are greater than shown). These errors are corrected in Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data.

A. In May 2016, when the original response to ORA DR-06, Q12 was provided, Applicants' High Pressure database had not been updated with documented wall thickness information and therefore the wall thickness defaulted to unknown for the CUM Station [redacted] to [redacted]. When a wall thickness value is unknown in the database, it is conservatively assigned a wall thickness value that provides a margin of safety. The conservative value assigned based on the diameter and year of installation, and which was reflected in the database at the time the May 12, 2016 response to ORA DR-06, Q12 was prepared, was [redacted] wall thickness for CUM Station [redacted] to [redacted]

B. As noted above, the response to ORA DR-06 Q12, refers to CUM Station [redacted] to [redacted] which is ENG Station [redacted] to [redacted]. As reflected in Applicants' response to ORA DR-25, Q1, the correct wall thickness for this segment is [redacted] inch for pipe installed in 2004. Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data reflects the [redacted] inch wall thickness. Documents establishing this value are attached as *ORA 84_Q1_Attachments.pdf.*

C. Confirmed. See also response to Subpart F below.

D. Confirmed. See also response to Subpart F below.

E. The attached pipe specification supports the [redacted]" wall thickness. See also response to Subpart F below.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

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Date Requested: May 5, 2017
Date Responded: May 22, 2017

F. Stationing in question is not a valid station range. Applicants infer that ORA meant [redacted] not [redacted] and provides the following response. The two segments from question parts C through E are two separate segments of pipe. The stationing provided was in "Engineering Stationing," which may appear to have overlaps. However, this issue is commonly associated with preserving the memorialized engineering station values. The stationing is in fact for two different segments of pipe. This is shown through what we title "Cumulative Stationing" which is the direct count down the line of the pipeline which shows that these two segments are indeed following each other. See table below for engineering and cumulative stationing for these two segments.

Line Number	Engineering Station Start	Engineering Station End	Cumulative Station Start	Cumulative Station End
1600	[redacted]	[redacted] [redacted]	[redacted]	[redacted]
1600	[redacted]	[redacted]	[redacted]	[redacted]

*Output reports only display one station value of a station equation

G. As discussed above, Applicants' response to ORA DR-06, Q12, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data, refers to "cumulative stations," not "engineering stations." With respect to the updated value for this pipe segment, see responses to Question 1(a)-(b) and Question 11.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

QUESTION 2:

For engineering stations [redacted] to [redacted]:

a. Provide all supporting information for the original May 2016 response to ORA DR-06, Q12 that supported a wall thickness of [redacted] inches.

b. Provide all supporting information for the April 2017 updated response to ORA DR-06, Q12 that supports a wall thickness of [redacted] inches.

c. Please provide all supporting information for the April 2017 updated response to ORA DR-25, Q1 that supports a wall thickness of [redacted] inches.

d. Provide all supporting information for the April 2017 update to ORA DR-25, Q1 supporting the wall thickness of [redacted] inches.

e. Please explain why SoCalGas/SDG&E provided inconsistent responses between the original ORA DR-06, Q12 and ORA DR-25, Q1 for engineering stations [redacted] to [redacted].

RESPONSE 2:

The question and response (and associated attachments) contains confidential information (shaded in gray) and is provided pursuant to Cal. Pub. Util. Code § 583, G.O. 66-C, D.16-08-024 and the accompanying declaration.

A. With respect to the pipeline segment that is the focus of Question 2, the "cumulative station" ("CUM Station") [redacted] to [redacted] (reflected in the response to ORA-DR06, Q12) is the same as "engineering station" ("ENG Station") [redacted] to [redacted]3 (reflected in the response to ORA-DR25, Q1). At the time the original response to ORA DR-06, Q12 was prepared, the High Pressure database was defaulted to unknown for the segment noted. When a wall thickness or grade value is unknown in the database, it is conservatively assigned a wall thickness and grade value that provides a margin of safety. The conservative value assigned based on the diameter and year of installation, and which was reflected in the database at the time the May 12, 2016 response to ORA DR-06, Q12 was prepared, was [redacted] wall thickness for CUM Station [redacted] to [redacted].

B. As noted above, the information provided in the response to ORA-DR-06 Q12, refers to CUM Station [redacted] to [redacted] is the same as ENG Station [redacted] to [redacted] (reflected in the response to ORA-DR25, Q1). As reflected in Applicants' response to ORA DR-25, Q1, the correct wall thickness for this segment is [redacted] inch for pipe installed in 1999. Applicants' May 22, 2017 Corrected and Updated Confidential

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Attachment to Applicants' Response to ORA DR 6, Question 12 L1600 Pipe Segment Data reflects the [redacted] inch wall thickness. Documents establishing this value are attached as *ORA 84_Q2_Attachments.pdf*.

C. The document supporting the [redacted] inch wall thickness for ENG Station [redacted] to [redacted] is attached *ORA 84_Q2_Attachments.pdf*.

D. See response to Question 2(c)

E. Please see response to Question 2(a)(b) and Question 11.

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QUESTION 3:

For engineering stations [redacted] to [redacted]:

a. Provide all supporting information for the original May 2016 response to ORA DR-06, Q12 that supported a wall thickness of [redacted] inches.

b. Provide all supporting information for the April 2017 updated response to ORA DR-06, Q12 that supports a wall thickness of [redacted] inches.

c. Please provide all supporting information for the April 2017 updated response to ORA DR-25, Q1 that supports a wall thickness of [redacted] inches.

d. Please explain why SoCalGas/SDG&E provided inconsistent responses between the original ORA DR-06, Q12 and ORA DR-25, Q1 for engineering stations [redacted] to [redacted].

RESPONSE 3:

The question and response (and accompanying attachments) contains confidential information (shaded in gray) and is provided pursuant to Cal. Pub. Util. Code § 583, G.O. 66-C, D.16-08-024 and the accompanying declaration.

A. With respect to the pipeline segment that is the focus of Question 3, the "cumulative station" ("CUM Station") [redacted] to [redacted] (reflected in the response to ORA-DR06, Q12) is the same as "engineering station" ("ENG Station") [redacted] to [redacted] (reflected in the response to ORA-DR25, Q1). At the time the original response to ORA DR-06, Q12 was prepared, the High Pressure Database did not reflect the documented wall thickness information and was defaulted to unknown for the segment noted. When a wall thickness value is unknown in the database, it is conservatively assigned a wall thickness value that provides a margin of safety. The conservative value assigned based on the diameter and year of installation, and which was reflected in the database at the time the May 12, 2016 response to ORA DR-06, Q12 was prepared, was [redacted] wall thickness for CUM Station [redacted] to [redacted].

B. As noted above, the information provided in the response to ORA -DR-06 Q12 refers to CUM Station [redacted] to [redacted] which is the same as ENG Station [redacted] to [redacted] (reflected in the response to ORA-DR25, Q1). As reflected in Applicants' response to ORA DR-25, Q1, the correct wall thickness for this segment is [redacted] inch

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for pipe installed in 2006.[1] Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data, as well as Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 L1600 Pipe Segment Data, reflects the [redacted] inch wall thickness. Documents establishing this value are attached as *ORA 84_Q3_Attachment.pdf*.

C. The documents attached as *ORA 84_Q3_Attachment.pdf* supports the information provided as part ORA DR-25 Q1 for ("ENG Station") [redacted] to [redacted].

D. Please see the responses to Question 3(a)-(b) and Question 11.

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[1] In the accompanying backup documentation, there are two wall thicknesses shown (e.g. [redacted] and [redacted]). The conservative figure was selected for use in the Applicants' High Pressure Database.

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QUESTION 4:

For engineering stations [redacted] to [redacted]0:

a. Provide all supporting information for the original May 2016 response to ORA DR-06, Q12 that supported a yield strength of [redacted].

b. Provide all supporting information for the April 2017 updated response to ORA DR-06, Q12 that supports a yield strength of [redacted].

c. Provide all supporting information for the April 2017 updated response to ORA DR-25, Q1 that supports a yield strength of [redacted].

d. Please explain why SoCalGas/SDG&E provided inconsistent responses between the original ORA DR-06, Q12 and ORA DR-25, Q1 for engineering stations [redacted] to [redacted].

RESPONSE 4:

The question and response (and accompanying attachment) contains confidential information (shaded in gray) and is provided pursuant to Cal. Pub. Util. Code § 583, G.O. 66-C, D.16-08-024 and the accompanying declaration.

A. With respect to the pipeline segment that is the focus of Question 4, the "cumulative station" ("CUM Station") [redacted] to [redacted] (reflected in the response to ORA-DR06, Q12) is the same as "engineering station" ("ENG Station") [redacted] to [redacted] (reflected in the response to ORA-DR25, Q1). At the time the original response to ORA DR-06, Q12 was prepared, the High Pressure Database did not reflect the documented grade information and was defaulted to unknown for the segment noted. When a grade value is unknown in the database, it is conservatively assigned a grade value that provides a margin of safety. The conservative yield strength value assigned, and which was reflected in the database at the time the May 12, 2016 response to ORA DR-06, Q12 was prepared, was [redacted]

B. As noted above, the information provided in the response to ORA -DR-06 Q12 refers to CUM Station [redacted] to [redacted], which is the same as ENG Station [redacted] to [redacted] (reflected in the response to ORA-DR25, Q1). As reflected in Applicants' response to ORA DR-25, Q.1, the correct yield strength value for this segment is [redacted] for pipe installed in 1961. Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 L1600 Pipe Segment Data, as well as Applicants' April 27, 2017 Corrected and Updated

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Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 L1600 Pipe Segment Data, reflects the [redacted] yield strength value. Documents establishing this value are attached as *Attachments ORA 84_Q4_Attachment.pdf*.

C. Documents attached as Attachment ORA 84_Q4_Attachment.pdf support the yield strength of [redacted] for "ENG Station" [redacted] to [redacted].

D. See responses to Question 4(a)-(b) and Question 11

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QUESTION 5:

For engineering stations [redacted] to [redacted]

a. Provide all supporting information for the original May 2016 response to ORA DR-06, Q12 that supported a yield strength of [redacted]

b. Provide all supporting information for the April 2017 updated response to ORA DR-06, Q12 that supported a yield strength of [redacted].

c. Provide all supporting information for the April 2017 updated response to ORA DR-25, Q1 that supports a yield strength of [redacted].

d. Please explain why SoCalGas/SDG&E provided inconsistent responses between the original ORA DR-06, Q12 and ORA DR-25, Q1 for engineering stations [redacted] to [redacted].

RESPONSE 5:

The question and response (and accompanying attachment) contains confidential information (shaded in gray) and is provided pursuant to Cal. Pub. Util. Code § 583, G.O. 66-C, D.16-08-024 and the accompanying declaration.

A. With respect to the pipeline segment that is the focus of Question 5, the "cumulative station" ("CUM Station") [redacted] to [redacted] (reflected in the response to ORA-DR06, Q12) is the same as "engineering station" ("ENG Station") [redacted] to [redacted] (reflected in the response to ORA-DR25, Q1). At the time the original response to ORA DR-06, Q12 was prepared, the High Pressure Database did not reflect the documented grade information and was defaulted to unknown for the segment noted. When a grade value is unknown in the database, it is conservatively assigned a grade value that provides a margin of safety. The conservative yield strength value assigned, and which was reflected in the database at the time the May 12, 2016 response to ORA DR-06, Q12 was prepared, was [redacted]0.

B. As noted above, the information provided in the response to ORA -DR-06 Q12 refers to CUM Station [redacted] to [redacted], which is the same as ENG Station [redacted] to [redacted] (reflected in the response to ORA-DR25, Q1). As reflected in Applicants' response to ORA DR-25, Q1, the correct yield strength value for this segment is [redacted] for pipe installed in 1961. Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 L1600 Pipe Segment Data, as well as Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 L1600

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Pipe Segment Data, reflects the [redacted] yield strength value. Documents establishing this value are attached as *ORA 84_Q5_Attachments.pdf*.

C. The documents attached as Attachment ORA 84_Q5_Attachments.pdf support the yield strength of [redacted] for "ENG Station" [redacted] to [redacted].

D. Please see the responses to Question 5(a)-(b) and Question 11.

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QUESTION 6:

For engineering stations [redacted] to [redacted]:

a. Provide all supporting information for the original May 2016 response to ORA DR-06, Q12 that supported a yield strength of [redacted].

b. Provide all supporting information for the April 2017 updated response to ORA DR-06, Q12 that supports a yield strength of [redacted]

c. Provide all supporting information for the April 2017 updated response to ORA DR-25, Q1 that supports a yield strength of [redacted]

d. Please explain why SoCalGas/SDG&E provided inconsistent responses between the original ORA DR-06, Q12 and ORA DR-25, Q1 for engineering stations [redacted] to [redacted]

RESPONSE 6:

The question and response (and accompanying attachment) contains confidential information (shaded in gray) and is provided pursuant to Cal. Pub. Util. Code § 583, G.O. 66-C, D.16-08-024 and the accompanying declaration.

A. With respect to the pipeline segment that is the focus of Question 6, the "cumulative station" ("CUM Station") [redacted] to [redacted] reflected in the response to ORA-DR06, Q12) is the same as "engineering station" ("ENG Station") [redacted] to [redacted] (reflected in the response to ORA-DR25, Q1). At the time the original response to ORA DR-06, Q12 was prepared, the High Pressure Database did not reflect the documented grade information and was defaulted to unknown for the segment noted. When a grade value is unknown in the database, it is conservatively assigned a grade value that provides a margin of safety. The conservative yield strength value assigned, and which was reflected in the database at the time the May 12, 2016 response to ORA DR-06, Q12 was prepared, was [redacted].

B. As noted above, the information provided in the response to ORA -DR-06 Q12 refers to CUM Station [redacted] to [redacted], which is the same as ENG Station [redacted] to [redacted] (reflected in the response to ORA-DR25, Q1). As reflected in Applicants' response to ORA DR-25, Q1, the correct yield strength value for this segment is [redacted] for pipe installed in 1962.[2] Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 L1600 Pipe Segment Data, as well as Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 L1600 Pipe Segment Data, reflects the [redacted] yield strength value. Documents establishing this value are attached as *ORA 84_Q6_Attachments.pdf*.

C. The document attached as Attachment *ORA 84_Q6_Attachments.pdf* supports the yield strength of [redacted] for "ENG Station" [redacted] to [redacted]

D. Please see the responses to Question 6(a)-(b) and Question 11.

[2] Since the May 2016 response to ORA DR-06, Q12, the High Pressure Database has been updated to reflect work on this Line 1600 segment. A small portion has been replaced with pipe that has a wall thickness of [redacted] inches and a yield strength of [redacted] psi. As a result of this work, the Cumulative Stationing for this line segment has changed, though not the Engineering Stationing. To maintain the comparability of the responses to ORA DR-06, Q12 and ORA DR-25, Q1, Applicants have not changed the reference to this line segment in the Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 L1600 Pipe Segment Data.

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QUESTION 7:

Please confirm that to identify the same areas of pipeline along Line 1600, two SoCalGas/SDG&E's Data Responses use different engineering stations. Specifically, confirm that the updated response to ORA DR- 25, Q1 uses engineering stations [redacted] to [redacted] to identify a specific area of Line 1600 pipeline, while the response to ORA DR-06, Q12 uses engineering stations [redacted] to cover that same area of pipeline?

RESPONSE 7:

The question above contains confidential information (shaded in gray) pursuant to Cal. Pub. Util. Code § 583, G.O. 66-C, D.16-08-024.

As set forth in response to Question 1, *Cumulative Stationing vs. Engineering Stationing*, the attachment to Applicants' response to ORA DR-06, Q12, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data (now further updated in Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 L1600 Pipe Segment Data), refers to "cumulative stations," not "engineering stations." By contrast, the attachment to Applicants' response to ORA DR-25, Q1, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR-25, Q1, refers to "engineering stations," not "cumulative stations."

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QUESTION 8:

If SoCalGas/SDG&E confirm question 7, please explain why SoCalGas/SDG&E have provided ORA with inconsistent Data Responses that show different engineering stations along Line 1600 to identify the same exact area of pipe.

RESPONSE 8:

As set forth in response to Question 1, *Cumulative Stationing vs. Engineering Stationing*, the attachment to Applicants' response to ORA DR-06, Q12, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data (now further updated in Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 L1600 Pipe Segment Data), refers to "cumulative stations," not "engineering stations." By contrast, the attachment to Applicants' response to ORA DR-25, Q1, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR-25, Q1, refers to "engineering stations," not "cumulative stations."

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QUESTION 9:

Please confirm that to identify the same areas of pipeline along Line 1600, certain SoCalGas/SDG&E Data Responses use different engineering stations. Specifically, confirm that the updated April 2017 response to ORA DR-25, Q1 uses engineering stations [redacted] to [redacted] to identify a specific area of Line 1600 pipeline, while the original May 2016 and updated April 2017 response to ORA DR-06, Q1 uses engineering stations [redacted] to cover that same area of pipeline. Explain the difference between the two data responses.

RESPONSE 9:

The question above contains confidential information (shaded in gray) pursuant to Cal. Pub. Util. Code § 583, G.O. 66-C, D.16-08-024.

As set forth in response to Question 1, *Cumulative Stationing vs. Engineering Stationing*, the attachment to Applicants' response to ORA DR-06, Q12, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data (now further updated in Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 L1600 Pipe Segment Data), refers to "cumulative stations," not "engineering stations." By contrast, the attachment to Applicants' response to ORA DR-25, Q1, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR-25, Q1, refers to "engineering stations," not "cumulative stations."

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QUESTION 10:

Explain why the response to ORA DR-06, Q12 contains different engineering stations than the response to ORA DR-25, Q1. If the responses come from different databases or other systems, please explain the underlying documentation and what part of the SCG/SDG&E organization(s) bears responsibility for their maintenance and accuracy.

RESPONSE 10:

As set forth in response to Question 1, *Cumulative Stationing vs. Engineering Stationing*, the attachment to Applicants' response to ORA DR-06, Q12, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data (now further updated in Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 L1600 Pipe Segment Data), refers to "cumulative stations," not "engineering stations." By contrast, the attachment to Applicants' response to ORA DR-25, Q1, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR-25, Q1, refers to "engineering stations," not "cumulative stations."

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QUESTION 11:

Do SCG/SDG&E's updates to its responses to ORA DR-06 Q12 identified in this data request mean that SCG/SDG&E claims it provided inaccurate information to ORA in the instances where that information have been updated? If not, please explain.

RESPONSE 11:

To the extent that ORA is referring to differences in stationing, as set forth in response to Question 1, *Cumulative Stationing vs. Engineering Stationing*, the attachment to Applicants' response to ORA DR-06, Q12, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data (now further updated in Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 L1600 Pipe Segment Data), refers to "cumulative stations," not "engineering stations." By contrast, the attachment to Applicants' response to ORA DR-25, Q1, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR-25, Q1, refers to "engineering stations," not "cumulative stations."

With respect to the values attributed to the specific pipeline segments corrected in Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data (and now further updated in Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR 6, Question 12 1600 Pipe Segment Data), Applicants provided the information for the relevant segments that was in Applicants' High Pressure Database at the time of the original and updated responses. As discussed above, the High Pressure Database was updated from conservative default values for certain segments to actual values for those segments between the May 12, 2016 response to ORA DR-06, Q12 and the June 13, 2016 response to SED DR 3, Q2, a copy of which was provided to ORA in Applicants' July 15, 2016 response to ORA DR 19 and subsequently resubmitted to ORA on August 4, 2016 following an August 2, 2016 amended response to SED DR 3 Q2.

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QUESTION 12:

Please explain why allegedly inaccurate information was originally provided in response to ORA DR-06, Q12. SoCalGas/SDG&E stated in the Amended Response to ORA DR-19, Q7: “The April 27, 2017 Amended Response to ORA DR-06, Question 12 (and the Corrected and Updated Attachment thereto) reflects the pipeline segment data previously provided to ORA in: [ORA DR-25, Q1; amending ORA DR- 19, which amended SED DR-03, Q2].”

RESPONSE 12:

Please see the response to Question 11.

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QUESTION 13:

Please provide the change log or other similar information that tracks changes to the database or information used to provide the response to ORA DR-06, Q12. If no such log is available, explain:

a. How SCG/SDG&E tracks and maintains attribute information of its natural gas pipelines to ensure compliance with state and federal natural gas pipeline safety requirements.

b. How SCG/SDG&E tracks changes and updates to attribute information of its natural gas pipelines to ensure compliance with state and federal natural gas pipeline safety requirements.

RESPONSE 13:

The Attachments identified in response to Questions 1-6 include documentation of the changes to the High Pressure Database. See documents entitled *FORM 2112 PIPELINE DATABASE UPDATE*.

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QUESTION 14:

How many different sources of information did SCG/SDG&E use to determine the pipeline attributes of Line 1600 it provided ORA in the response to ORA DR-06, Q12? Please list all such sources.

RESPONSE 14:

Applicants have consistently responded to all data requests from the same data source, the High-Pressure Data Base, and documents referenced therein.

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QUESTION 15:

How many different sources of information did SCG/SDG&E use to determine the pipeline attributes of Line 1600 it provided ORA in the April 2017 updated response to ORA DR-06, Q12? Please list all such sources.

RESPONSE 15:

Applicants have consistently responded to all data request from the same data source, the High-Pressure Data Base, and the documents referenced therein. As discussed in response to Question 11, the High Pressure database was updated from conservative default values for certain segments to actual documented values for those segments between the May 12, 2016 response to ORA DR-06, Q12 and the June 13, 2016 response to SED DR 3, Q2, a copy of which was provided to ORA in Applicants' July 15, 2016 response to ORA DR 19, and has been further updated and resubmitted to ORA thereafter.

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QUESTION 16:

How many different sources of information did SCG/SDG&E use to determine the pipeline attributes of Line 1600 it provided ORA in the response to ORA DR-25, Q1. Please list all such sources.

RESPONSE 16:

Applicants have consistently responded to all data request from the same data source, the High-Pressure Data Base, and the documents referenced therein. As discussed in response to Question 11, the High Pressure Database was updated from conservative default values for certain segments to actual documented values for those segments between the May 12, 2016 response to ORA DR-06, Q12 and the June 13, 2016 response to SED DR 3, Q2, a copy of which was provided to ORA in Applicants' July 15, 2016 response to ORA DR 19, and has been further updated and resubmitted to ORA thereafter.

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QUESTION 17:

How many different sources of information did SCG/SDG&E use to determine the pipeline attributes of Line 1600 it provided ORA in the April 2017 updated response to ORA DR-25, Q1. Please list all such sources.

RESPONSE 17:

Applicants have consistently responded to all data request from the same data source, the High-Pressure Data Base, and the documents referenced therein. As discussed in response to Question 11, the High Pressure Database was updated from conservative default values for certain segments to actual documented values for those segments between the May 12, 2016 response to ORA DR-06, Q.12 and the June 13, 2016 response to SED DR 3, Q2, a copy of which was provided to ORA in Applicants' July 15, 2016 response to ORA DR 19, and has been further updated and resubmitted to ORA thereafter.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

QUESTION 18:

When answering questions 14, 15, 16, and 17, if SCG/SDG&E used a data source in one response it did not use in another response, please explain why.

RESPONSE 18:

NA. All data sources were the same.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

QUESTION 19:

When answering questions 14, 15, 16, and 17 if SCG/SDG&E did not use a data source in one response that it used in another response, please explain why.

RESPONSE 19:

NA. All data sources were the same.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

QUESTION 20:

Provide the name(s), title(s), and part of the SoCalGas/SDG&E organization for who:

a. Prepared the original response to ORA DR-06, Q12.
b. Prepared the April 2017 updated response to ORA DR-06, Q12.
c. Prepared the original response to SED DR-03, Q2 (and thus ORA DR-25, Q1).
d. Prepared the April 2017 updated response to SED DR-03, Q2 (and thus ORA DR-25, Q1).
e. Prepared the original response to ORA DR-19, Q7.
f. Prepared the April 2017 updated response to ORA DR-19, Q7.

RESPONSE 20:

SDG&E and SoCalGas (Applicants) object to the term “prepared” as vague and ambiguous, and thus potentially overbroad and unduly burdensome if deemed to include every employee who contributed data to the High Pressure Database. Subject to and without waiving their objections, Applicants respond as follows: These responses were prepared by various personnel in the pipeline integrity department under the direction of Maria Martinez (Director - Pipeline Integrity).

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

Update to ORA DR-19, Q7

QUESTION 21:

Please confirm that at no point in the response to ORA DR-25 Q1 has SCG/SDG&E stated that the information contained therein was an update or revision to the response contained in ORA DR-06, Q12.

RESPONSE 21:

ORA DR-25 Q1 specifically requested “Please provide an updated version of the table provided in response to SED DR-3, Q2 and Q3, that includes the following columns appended to the end”. Applicants provided the updated information requested by ORA DR-25 Q1.

ORA clearly was aware of the later data provided to SED, and received the updated data it requested through ORA DR-25 Q1. Although SCG/SDG&E did not state in the response to ORA DR-25, Q1 that it superseded the earlier response to ORA DR-06, Q12, SCG/SDG&E assumed that ORA was aware that it was receiving “updated” data as ORA DR-25, Q1 specifically requested it. ORA also received updated data through its receipt of SCG/SDG&E’s responses to SED DR-3, Q2 and Q3.

At no time before receiving ORA’s testimony on April 17, 2017 was SCG/SDG&E aware that ORA was relying on the un-updated data provided in response to ORA DR-06, Q12, rather than the updated data provided to ORA in response to ORA DR-19 and ORA DR-25, Q1. Despite serving thousands of data request questions on SCG/SDG&E, ORA never asked about the differences in Line 1600 segment data between the early response to ORA DR-06, Q12 and the later responses to ORA DR-19 and ORA DR-25, Q1, despite being aware of the discrepancies as set forth in ORA’s April 17, 2017 testimony. SCG/SDG&E regrets that ORA relied upon the earlier response rather than the later responses with the updated data.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

QUESTION 22:

Please confirm that at no point in the response to ORA DR-19 Q7, prior to the April 2017 update, has SCG/SDG&E stated that the information contained therein was an update or revision to the response contained in ORA DR-06, Q12.

RESPONSE 22:

Please see the response to Question 21 above.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

QUESTION 23:

Please confirm that ORA DR-19, Q7 specifically asked for the differences between the response to ORA DR-06, Q12 and the 1968 SDG&E report provided in response to ORA DR-14, Q2, which asked:

> a. Please provide a copy of the pressure log used to establish the Maximum Allowable Operating Pressure of Line 1600.
>
> b. What was the maximum in service pressure experienced by Line 1600 between 1965 and 1970?

RESPONSE 23:

ORA DR-19, Q7 states: "Please explain the discrepancies in pipeline records between SDG&E's 1968 report on Line 1600 (provided in response to ORA DR-14 Q2) and the L1600 pipe segment data (provided in response to ORA DR-06 Q12)."

ORA DR-14, Q2 states, in part: "a. Please provide a copy of the pressure log used to establish the Maximum Allowable Operating Pressure of Line 1600. b. What was the maximum in service pressure experienced by Line 1600 between 1965 and 1970?"

a. Please see response to ORA DR14 Q2. In addition, 49 CFR § 192.619(c) does not specify actual copies of written pressure records to be preserved.

b. Please see response to ORA DR14 Q2.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

QUESTION 24:

Please confirm that the response to ORA DR-19, Q7 explicitly included the explanatory factors of "changes to the pipelines due to various reasons, such as replacement or relocations", but omitted the information provided in the April 2017 updated response to ORA DR 19, Q7.

RESPONSE 24:

This response contains confidential information (shaded in gray) and is provided pursuant to Cal. Pub. Util. Code § 583, G.O. 66-C, D.16-08-024 and the accompanying declaration.
Applicants' July 15, 2016 response to ORA DR-19, Q7 states: "The pipeline record provided in ORA DR-14 Q2 was developed in 1968, and the pipeline record provided in ORA DR-06 Q12 is the current status of Line 1600, which accounts for changes to the pipelines due to various reasons, such as replacement or relocations. The primary segment is still the 16" Diameter, [redacted]" Wall Thickness and [redacted] SMYS in the current report (see DR 14)."

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

QUESTION 25:

Please confirm that the response to SED DR-3, Q2 was based on "the Maximum Allowable Operating Pressure (MAOP) validation process".

RESPONSE 25:

As stated in SoCalGas/SDG&E response to SED DR-3 Q2: "As part of the Maximum Allowable Operating Pressure (MAOP) validation process each segment was analyzed to determine the appropriate MAOP based on year of installation, pipe properties, class location, test records and historical operating pressures."

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

QUESTION 26:

Regarding Line 1600, has SCG/SDG&E ever found errors in the data during the MAOP validation process? Please explain and indicate if the information was more conservative (i.e. the data SCG/SDG&E had been using resulted in lower MAOPs than the data discovered during the MAOP validation process) or was less conservative (i.e. the data SCG/SDG&E had been using resulted in higher operating pressure than the data discovered during the MAOP validation process).

RESPONSE 26:

Applicants object that “ever found errors in the data during the MAOP validation process” is vague and ambiguous, and thus could be overbroad, unduly burdensome and beyond the scope of this proceeding. Assuming that ORA is asking about whether errors were introduced into Applicants’ High Pressure Database, Applicants respond as follows: No, until a reliable source document is found conservative numbers are used, which provide a margin of safety. Basing the analysis on conservative values sets the maximum allowable operating pressure (MAOP) as determined by Section 192.619(a)(1) at lower setting.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

QUESTION 27:

If any of the data discovered in the MAOP validation process resulted in lowering the MAOP of Line 1600, please identify all such data, including the initial data that was used, and the updated data. Please be sure to include in spreadsheet format all necessary factors to identify this change, including:

a. Engineering stations;

b. Date of the discovery of the new data;

c. All attributes needed to calculate design based MAOP under 49 CFR Section 192.105 that changed due to discovery of the new data. Please be sure to itemize each attribute provided in response to question 27c.

RESPONSE 27:

No data resulted in the change of the MAOP of Line 1600.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

QUESTION 28:

Please confirm that the 1968 report to the Commission, provided in response to ORA DR-14, Q2, erroneously states that the 14" segments of Line 1600 under Lake Hodges had not been tested.

RESPONSE 28:

The 1968 report to the Commission provided reflected information available at the time. As part of the MAOP validation process, Applicants located the testing documents for the 14" section of pipeline.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(84th DATA REQUEST FROM ORA)

Date Requested: May 5, 2017
Date Responded: May 22, 2017

QUESTION 29:

Are there any other errors of which SoCalGas/SDG&E is now aware of in the 1968 report to the Commission, provided in response to ORA DR-14, Q2?

RESPONSE 29:

Applicants object that this Question is vague and ambiguous, and thus may be overbroad, unduly burdensome and beyond the scope of this proceeding. To the extent that the Question is limited to errors regarding Line 1600 wall thickness and yield strength, and without waiving their objections, Applicants respond as follows: No.

**BEFORE THE PUBLIC UTILITIES
COMMISSION OF THE STATE OF CALIFORNIA**

**DECLARATION OF MARIA MARTINEZ
REGARDING CONFIDENTIALITY OF CERTAIN DATA/DOCUMENTS
PURSUANT TO D.16-08-024**

I, Maria Martinez, do declare as follows:

1. I am the Director of Pipeline Integrity for San Diego Gas & Electric Company ("SDG&E") and Southern California Gas Company ("SoCalGas"). I have been delegated authority to sign this declaration by Douglas M. Schneider, Vice President of System Integrity and Asset Management for SDG&E and SoCalGas. I have reviewed the Response to ORA DR 84, Question 1 – 28 and the corresponding attachments, submitted concurrently herewith ("ORA 84_Q1_ Attachment.pdf" and "ORA 84_Q2_ Attachment.pdf", "ORA 84_Q3_ Attachment.pdf" , "ORA 84_Q4_ Attachment.pdf" , "ORA 84_Q5_ Attachment.pdf", "ORA 84_Q6_ Attachment.pdf") in response to the Office of Ratepayer Advocates ("ORA") data request ORA DR 84. I am personally familiar with the facts and representations in this Declaration and, if called upon to testify, I could and would testify to the following based upon my personal knowledge and/or belief.

2. I hereby provide this Declaration in accordance with Decision ("D.") 16-08-024 to demonstrate that the confidential information ("Protected Information") provided in response to the data request ORA DR 84, Question 1-6 & 24 are within the scope of data protected as confidential under applicable law, and pursuant to California Public Utilities Code ("P.U. Code") § 583 and General Order ("GO") 66-C, as described in Attachment A hereto.

3. In accordance with the legal authority described herein, the Protected Information should be protected from public disclosure.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge.

Executed this 19th day of May 2017, at Los Angeles, California.

Maria Martinez

Maria Martinez
Director of Pipeline Integrity
San Diego Gas & Electric and
Southern California Gas Company

ATTACHMENT A

SDG&E and SoCalGas Request for Confidentiality on the following Protected Information in its response to ORA DR 84, Question 1-6 and 24

Location of Data	Description of Data	Applicable Confidentiality Provisions	Basis for Confidentiality
ORA DR 84 Q1_Attachment ORA DR 84 Q2_Attachment	Q1 Page 1:, Completed/Approved By (Personnel Names), Stationing (Location), Wall Thickness and Pipe Grade Q1 Page 2: Test Chart, Wall Thickness, Grade Q1 Page 3: Diameter, Wall Thickness, Test Pressure Parameters, Grade Q1 Page 4: Test Chart, Wall Thickness, Grade Q1 Page 5: Job Description, Location, Class Location, Design Factor, Grade, Wall Thickness, Specification (SMC), Yield Pressure, Design Pressure, Test Parameters (Medium, Duration, Pressure). Q1 Page 6: Job Description, Location, Class Location, Design Factor. Q2 Page 1: Completed By, Grade, Stationing, and Approved By Q2 Page 2-5: Wall, Pressure Test Parameters, Personnel Information and Specific Location.	The Pipeline and Hazardous Materials Safety Administration ("PHMSA") guidelines in the Federal Register, Vol 81, pg. 40764, published on 6/22/2016 and U.S. Department of Homeland Security Transportation Security Administration ("TSA") guidelines consider the data to be restricted pipeline information. Critical Energy Infrastructure Information ("CEII") under 18 CFR § 388.113(c); Federal Energy Regulatory Commission ("FERC") Orders 630, 643, 649, 662,683, and 702 (defining CEII). Critical Infrastructure Information ("CII") under 6 U.S.C. §§ 131(3), 133(a)(1)(E); 6 CFR §§ 29.2(b), 29.8 (defining CII and restricting its disclosure). Cal. Gov't Code § 6254(e) exempts from mandatory disclosure, plant production data, and similar information relating to utility systems. Pressure information is also exempt from public disclosure per Cal. Gov't Code § 6254(e). Personnel Information - Gov't Code §6254(c) ("disclosure of which would constitute an unwarranted invasion of personal privacy").	"Wall Thickness" and "Yield Strength" are specific engineering design information about an existing critical infrastructure that could be used to determine the criticality of a gas facility and identify vulnerabilities of the gas delivery network. The values can be used to calculate stress levels of a pipe. Because of the critical nature of these attributes, they have been identified by PHMSA to be restricted attributes available only to government officials in the Federal Register Vol. 81, pg. 40764 published in 6/22/2016. "Pipe Diameter" is a specific engineering design value depicting an attribute of a proposed or existing critical infrastructure that could be used to determine the criticality of a gas facility and identify vulnerabilities of the gas delivery network. The value can be used to identify the volume of gas present in an area and ascertain the relative potential consequences of intentional acts against the gas transportation and distribution network. Because of the critical nature of the attribute, it has been identified by PHMSA to be a restricted pipeline attribute in the

ORA DR 84 Q3_Attachment ORA DR 84 Q4_Attachment ORA DR84 Q5_Attachment	Q3 Page 1:, Completed/Approved By (Personnel Names), Stationing (Location), and Pipe Grade Q3 Page 2: Job Description, Location, Class Location, Design Factor, Length, Design Level, Yield Pressure, Pressure, Grade, Wall Thickness, Specification (SMC), Yield Pressure, Design Pressure, Test Parameters (Medium, Duration, Pressure), and Personnel Information Q3 Page 3: Job Description, Location, Class Location, Design Factor, Test Parameters (Medium, duration, pressure, and length) and Personnel Information Q3 Page 4: Job Description/Scope and Personnel Information Q4 Page1: Completed/Approved By (Personnel Names), Stationing (Location), Wall Thickness and Grade Q4 Page2: Stationing (Location), Wall Thickness, Grade, and Approved by Q4 Page3-5: Specific Location, Personnel Information, Wall Thickness		Federal Register Vol 81, pg. 40764 published on 6/22/2016. Diameter is also exempt from public disclosure per the CEII and CII regulations for the same security reasons. Operating "pressure" (i.e., MAOP) is a specific engineering design value as well as an operating parameter depicting an attribute of an existing critical infrastructure. This operating parameter could be used to determine the criticality of a gas pipe or facility and identify vulnerabilities of the gas delivery network. The release of this operating parameter is detrimental to public safety as it can be used as a means to identify the volume of gas present and potential energy that could be released in an area in order to identify the potential consequences of an intentional act of sabotage. Because of the critical nature of the parameter, it has been identified by PHMSA to be restricted pipeline information as well being an SSI element in the Federal Register Vol 81, pg. 40764 published on 6/22/2016. Pressure information is also exempt from public disclosure per the CEII and CII regulations for the same security reasons. Personnel Information - Gov't Code §6254(c) ("disclosure of which would constitute an unwarranted invasion of personal privacy").

	Q5 Page1: Completed/Approved By (Personnel Names), Stationing (Location), Wall Thickness and Grade Q5 Page2: Stationing (Location), Wall Thickness, Grade, and Approved by Q5 Page3-5: Specific Location, Personnel Information, Wall Thickness		
ORA DR 84 Q6_Attachment	Q6 Page 1: Completed/Approved By (Personnel Names), Stationing (Location), Wall Thickness and Grade Q6 Page 2: Diameter, Wall Thickness, Grade, and Personnel Information		
ORA-84.doc	Q24, Page 5-17, 35: Stationing (Location), Wall Thickness and Grade		

Attachment B-6

Utilities' Response to ORA DR 51, Q3

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-51)

Date Requested: November 15, 2016
Date Responded: November 30, 2016

QUESTION 3:

Resolution No. SED-1 also required that SoCalGas/SDG&E, "Replace segments on Line 1600 from Engineering Stations "17-131". Also, on July 14, 2016, SoCalGas/SDG&E wrote to the CPUC's Executive Director, "As directed, the pipeline segment for Engineering Station 17-131 will be replaced. The Utilities plan to complete this work by December 31, 2016 with construction likely to begin in the 4th quarter of 2016. . . As more details are developed or if a change in schedule is necessary to avoid system or customer impacts, the Utilities will provide an update to SED."

a. What is the status of SoCalGas/SDG&E's replacement of the Line 1600 segment for Engineering Station 17-131?

b. If the replacement of Engineering Station 17-131 is complete, were there anomalies, features, or pipe conditions for Engineering Station 17-131 that differed from information in SDG&E/SoCalGas' records? Please explain.

c. If the replacement of Engineering Station 17-131 is complete, please provide all additional anomalies, or unusual pipe features or conditions that SDG&E/SoCalGas found.

RESPONSE 3:

a. The pipe segment for Engineering Station 17-131 replacement was completed on October 26, 2016.

b. Seven (7) linear anomalies at the EFW longitudinal seam were detected through nondestructive examination (NDE) and this discovery is consistent with the Applicants experience and observations for pipe segments of similar vintage and longitudinal seam type for this pipeline. The anomalies will be submitted for additional testing to characterize the anomalies. Procurement of services with a third party vendor is in progress.

c. No additional anomalies, features or conditions other than what was provided in Response 3b were discovered.

Attachment B-7

Utilities' Response to ORA DR-55, Q13

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-55)

Date Requested: November 23, 2016
Date Responded: December 15, 2016

QUESTION 13:

On the basis of the engineering assumptions used for the portion of Line 1600 between engineering stations 17-131, please confirm that:

a. The MAOP of design is 1312.5 (without the design factor) based on SCG/SDG&E's assumptions.
b. That for most of its operational history, this segment of pipeline would have been operating at 60.9% of its SMYS.
c. That this segment of pipeline was installed in, what by today's standards, is a Class 3 location, which allows a pipe to only operate at or below 50% of SMYS.

RESPONSE 13:

a. Based on established conservative values, the design calculation would be 1312, however, as previously stated, confirmation of those values is pending additional research and testing.

b. Applicants cannot confirm until inspection and test results from the retired pipe segment are received and validated.

c. The retired segment, if still in operation, would be operating in class 3.

Attachment B-8

Utilities' Response to ORA DR-46, Q4

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-46)
Date Requested: November 3, 2016
Date Responded: November 18, 2016

QUESTION 4:

Subject: Engineering Assumptions

For how many years has SoCalGas/SDG&E been operating Line 1600 using assumed data for the section of pipe that was ordered to be replaced under Resolution SED-01?

RESPONSE 4:

Applicants object to this Question on the ground that it assumes facts not in evidence. Subject to and without waiving their objection, Applicants respond as follows.

On an annual basis, operators are required to submit a Transmission Annual report to the Pipeline and Hazardous Materials Safety Administration (PHMSA) (Form F71002-1). In 2012, PHMSA required operators to provide an MAOP Determination (Part Q) to categorize the method per 49 CFR 192.619 used to establish MAOP for transmission pipelines. During this process Applicants identified that the segment that was ordered to be replaced under Resolution SED-01 had limited information regarding the wall thickness and grade as part of the installation work order. However, using this limited information combined with Applicants' engineering design standards, materials and standards catalogs, material requisitions and purchase orders, Applicants were able to establish conservative minimum values for wall thickness and grade and prefixed them "DT" to indicate additional data research or nondestructive testing should be completed. Confirming these values, Applicants performed a physical inspection of this segment of pipe and found that the physically measured wall thickness was consistent with wall tolerances published for .250 inch 16" pipe in API 5L. In fact, the physical measurements on average across multiple points was .270-inch. Thus providing further validation of the minimum "DT" values employed for the pipe segment. It should be noted that the MAOP of the segment replaced under Resolution SED-01 is established per 49 CFR 192.619(c) and therefore the segment had demonstrated it could operate safely 800 psig.

Attachment B-9

Utilities’ Response to ORA DR-54, Q4

PUBLIC VERSION

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-54)

Date Requested: November 23, 2016
Date Responded: December 14, 2016

QUESTION 4:

On June 13, 2016, SoCalGas/SDG&E responded to ORA DR-14, Question 1, and indicated that an updated response would be provided. Has SoCalGas/SDG&E completed the entry into their database? If so, please provide the updated response. If not, when does SoCalGas/SDG&E expect to have the database updated?

RESPONSE 4:

The attachment contains confidential information provided pursuant to Cal. Pub. Util. Code § 583, General Order 66-C and D.16-08-024 and the accompanying declaration.

Attached is an amended confidential map from ORA DR-14 Question 1 with the updated information to date that has been entered into the HPPD database. Note: The recent replacement of segment 17-131 is not yet reflected in the database.

Attachment B-10

Utilities' Response to ORA DR-87, Q2

PUBLIC VERSION

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(87th DATA REQUEST FROM ORA)

Date Requested: May 23, 2017
Date Responded: June 1, 2017

QUESTION 2:

In response to ORA DR-84, Q11, SoCalGas/SDG&E stated:

> "As discussed above, the High Pressure Database was updated from conservative default values for certain segments to actual values for those segments between the May 12, 2016 response to ORA DR-06, Q12 and the June 13, 2016 response to SED DR 3, Q2, a copy of which was provided to ORA in Applicants' July 15, 2016 response to ORA DR 19…"

a. Please explain in detail what prompted SoCalGas/SDG&E to update their High Pressure Database between May 12, 2016 and June 13, 2016.
b. For how long had the High Pressure Database had incorrect information entered for the segments identified in ORA DR-84 Questions 1 to 6?
c. For Line 1600, when did SoCalGas/SDG&E complete MAOP validation? If there has been more than one period when MAOP validation has been considered complete, please provide each date, and an explanation of what occurred that prompted a new examination of MAOP validation.
d. What is the High Pressure Database used for?
e. What purposes, including but not limited to integrity management, are the cumulative stations (as described in the response to ORA DR-84 Q1) in the High Pressure Database used for?
f. What purposes, including but not limited to integrity management, are the engineering stations (as described in the response to ORA DR-84 Q1) in the High Pressure Database used for?

RESPONSE 2:

a. SDG&E and SoCalGas (Applicants) continually evaluate the High Pressure Database to identify additional updates and/or review its records. Further, the data requests received regarding Line 1600 afforded an opportunity to review the High Pressure Database and input additional updates between May and June 2016.

b. The High Pressure Database works as intended. The Applicants' use of conservative values should not be characterized as "incorrect information" as the process for establishing conservative values was developed to align with guidance provided by ASME B31.8S Section 4, Gathering, Reviewing and Integrating Data when the data available is not completely substantiated. As stated in Applicants' response to ORA DR-84, at the time the original response to ORA DR-06, Q12 was prepared, the High

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(87th DATA REQUEST FROM ORA)

Date Requested: May 23, 2017
Date Responded: June 1, 2017

Pressure Database was assigned conservative values for the segments noted in ORA DR-84 Questions 1 to 6. When a wall thickness or grade value is not completely substantiated through installation records in the High Pressure Database, it is conservatively assigned a wall thickness and grade value that provides a margin of safety. The conservative value was assigned based on the diameter and year of installation, and was appropriately reflected in the High Pressure Database at the time the May 12, 2016 response to ORA DR-06, Q12 was prepared and submitted.

c. Applicants completed the MAOP validation process as outlined by the Pipeline and Hazardous Materials Safety Administration (PHMSA) in June 2013. The segments involved in the ORA DR-84 data request did not impact the validated MAOP determination of Line 1600. The segments from ORA DR-84 Questions 1-3 using conservative wall thickness and grade values validated the MAOP of 640 psig and the segments from ORA DR-84 Questions 4-6 are qualified to be grandfathered.

d. The primary purpose of the High Pressure Database is to support the Applicants' integrity management program. It is used to represent the pipeline attributes for high pressure pipelines with geospatial references based on the source documentation within the installation package.

e. Cumulative stationing is a measurement down the centerline of the pipeline and is re-calculated each time the pipeline is modified; therefore, each reiteration of the pipe will have a new cumulative stationing value. The cumulative stationing facilitates calculating accurate lengths of the pipeline.

f. Engineering station values are memorialized on the pipeline and are intended to stay consistent over time with small modifications to account for realignments and reroutes. The benefit of "engineering stationing" is that attribute information can easily be associated to legacy drawings.

Attachment B-11

Utilities' Response to ORA DR-89, Q1

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(89th DATA REQUEST FROM ORA)

Date Requested: May 26, 2017
Date Responded: June 2, 2017

In response to ORA Data Request 84, Question 11, SoCalGas/SDG&E stated:

> Applicants provided the information for the relevant segments that was in Applicants' High Pressure Database at the time of the original and updated responses. As discussed above, the High Pressure Database was updated from conservative default values for certain segments to actual values for those segments between the May 12, 2016 response to ORA DR-06, Q12 and the June 13, 2016 response to SED DR 3, Q2, a copy of which was provided to ORA in Applicants' July 15, 2016 response to ORA DR 19 and subsequently resubmitted to ORA on August 4, 2016 following an August 2, 2016 amended response to SED DR 3 Q2.

In response to ORA Data Request 84, Question 1a, SoCalGas/SDG&E stated (confidential data redacted):

> In May 2016, when the original response to ORA DR-06, Q12 was provided, Applicants' High Pressure database had not been updated with documented wall thickness information and therefore the wall thickness defaulted to unknown for the CUM Station XXX to XXX. When a wall thickness value is unknown in the database, it is conservatively assigned a wall thickness value that provides a margin of safety. The conservative value assigned based on the diameter and year of installation, and which was reflected in the database at the time the May 12, 2016 response to ORA DR-06, Q12 was prepared, was XXX wall thickness for CUM Station XXX to XXX.

Ex. ORA-02-C Confidential Workpapers of M Botros, tab "Low Design Feet – CONF" identified a certain number of segments with weaker design features based on the May 2016 response to ORA Data Request 6, Question 12. In total 0.5 miles of weaker pipeline were identified as compared to the majority of Line 1600.

With these facts in mind:

<u>QUESTION 1:</u>

a. In May 2016, when the original response to ORA DR-06, Q12 was provided, please confirm that the data provided in the original response to ORA Data Request 6, Question 12 was the data from the High Pressure Database prior to the update SoCalGas/SDG&E

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stated in response to ORA Data Request 84 Question 1a. If not, provide the values in the High Pressure Database from that time.

b. If SoCalGas/SDG&E confirm the answer to question 1a immediately above, please also confirm that the original response to ORA DR-06, Q12 provided in May 2016 was the same information that was contained in the High Pressure Database at the time SoCalGas/SDG&E filed Application 15-09-013. If these two sets of information are not the same, please explain and provide all supporting evidence.

c. Identify all segments of Line 1600 including their length in feet, and their yield strength using Barlow's Formula, that had assumptions in the High Pressure Database at the time the application was filed.

d. At the time SoCalGas/SDG&E provided their original direct testimony, please confirm that the data provided in response to ORA Data Request 6, Question 12 was the data from the High Pressure Database. If not, provide the values in the High Pressure Database from that time.

e. Identify all segments of Line 1600 including their length in feet, and their yield strength using Barlow's Formula, that had assumptions in the High Pressure Database at the time the original direct testimony of SoCalGas/SDG&E was filed.

f. Please confirm that the High Pressure Database as of May 2016, prior to being updated as stated in response to ORA DR 84 Question 1a, identified engineering stations 17-131 as having a weaker MAOP of design than the majority of Line 1600.

g. Please confirm that based on the data in the High Pressure Database at the time of the August 2016 update to SED-3 demonstrates that the MAOP of Line 1600 would be approximately 24% of SMYS if operated at 320 psig.

h. Please confirm that Applicants had not proposed replacing engineering stations 17-131 as part of their proposal to derate Line 1600. If Applicants assert otherwise, please provide a specific reference to the testimony where SoCalGas/SDG&E stated they would replace this portion of Line 1600.

i. Provide a version of the information provided in SED-3 Question 2 at the time the application was filed.

j. Provide a version of the information provided in SED-3 Question 2 at the time the original direct testimony was filed.

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Date Requested: May 26, 2017
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k. Please confirm that by June 2014 SoCalGas/SDG&E had completed "active" MAOP validation of its entire natural gas transmission system. If not, please explain.

l. Please confirm that by June 2014 SoCalGas/SDG&E had completed "active" MAOP validation of Line 1600. If not, please explain.

m. Provide an active Excel spreadsheet that includes the following:

1. Shows each of the items needed to complete Barlow's Formula under 49 CFR Section 192.105.
2. Beginning with the date that Application 15-09-013 was filed, and ending with the date of this data request, identify each instance SoCalGas/SDG&E became aware of actual pipeline feature information on Line 1600 that was different from the information SoCalGas/SDG&E used to calculate pressure under 49 CFR Section 192.105. Be sure to identify each attribute that was different.
3. For each event identified in response to m.2, provide the supporting documentation.
4. For each even identified in response to m.2, include the date the supporting documentation was identified, the date the supporting documentation was entered into the High Pressure Database, and the date the safety attribute from the supporting documentation was used to calculate design pressure in compliance with 49 CFR Section 192.105.
5. For each event identified in response to m.2, identify when SoCalGas/SDG&E notified the Commission that updated information had become available regarding Line 1600, and what steps SoCalGas/SDG&E took to explain the updated information.
6. For each event identified in response to m.2, identify when SoCalGas/SDG&E notified Safety and Enforcement Division that updated information had become available regarding Line 1600, and what steps SoCalGas/SDG&E took to explain the updated information.
7. Has SoCalGas/SDG&E clarified to Safety and Enforcement Division that its data response to SED 3 was based upon updated information in the High Pressure Database, which had not been updated at the time Safety and Enforcement Division issued data request SED-3? If the answer is anything but an unqualified no, please provide all documentation showing that such clarification was shown to SED.
8. For each event identified in response to m.2, identify when SoCalGas/SDG&E notified parties to A.15-09-013 that updated information had become available regarding Line

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Date Requested: May 26, 2017
Date Responded: June 2, 2017

1600, what specific information had been updated, and what steps SoCalGas/SDG&E took to explain the basis updated information.

RESPONSE 1:

SDG&E and SoCalGas (Applicants) object that Question 1 seeks information not within the scope of this proceeding and which is unduly burdensome. ORA has records establishing the documented values for the Line 1600 segments that were amended in Applicants' April 27 and May 22, 2017 Corrected and Updated Confidential Attachments to Applicants' response to ORA DR-06, Q.12. Applicants' response to ORA DR-84 explained the changes in Applicants' High Pressure Database from the conservative default values included in Applicants' original May 12, 2016 response to ORA DR-06, Q.12 to the documented values in Applicants' later responses to SED and ORA. Question 1 now seeks extensive information regarding the data reflected in the High Pressure Database at various times in the past and calculations based upon that information. As ORA has documented values that establish that all segments of Line 1600 would be below 20% SMYS if de-rated to a 320 psig MAOP, such information is not relevant to any issue in this proceeding and the process of compiling such information is unduly burdensome. Without waiving and subject to their objections, Applicants respond as follows:

ORA appears to seek information regarding why Applicants concluded that de-rating Line 1600 to a 320 psig MAOP would result in all segments being under 20% SMYS, thus rendering Line 1600 a distribution line under 49 CFR § 192.3, at a time when the High Pressure Database still contained conservative default values for certain segments of Line 1600. Based upon what was known about Line 1600's construction, maintenance and operation, Applicants were confident that the weakest segments were constructed in 1949 using the original A.O. Smith pipe (wall thickness 0.250 and yield strength of 52,000) and that later installed segments were built to withstand equal or greater pressures (with equivalent or greater wall thickness and/or yield strength). Applicants intended to confirm this assumption before de-rating Line 1600, if approved by the Commission, either through records review and/or field data collection, non-destructive testing or destructive testing; if the assumption was not correct, then Applicants would have replaced the pipe segments before de-rating Line 1600.

Applicants note that following the removal of the pipe segment for engineering stations 17-131, and the subsequent testing of the pipe segment, it was determined that it had the attributes of the original A.O. Smith pipe (wall thickness 0.250 and yield strength of 52,000), as anticipated, also confirming the conservatism of the interim values.

Attachment B-12

Utilities' Response to ORA DR-19, Q7 and
Second Amended Response to ORA DR-19, Q7

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-19)

Date Requested: June 30, 2016
Date Responded: July 15, 2016

QUESTION 7:

Please explain the discrepancies in pipeline records between SDG&E's 1968 report on Line 1600 (provided in response to ORA DR-14 Q2) and the L1600 pipe segment data (provided in response to ORA DR-06 Q12).

RESPONSE 7:

The pipeline record provided in ORA DR-14 Q2 was developed in 1968, and the pipeline record provided in ORA DR-06 Q12 is the current status of Line 1600, which accounts for changes to the pipelines due to various reasons, such as replacement or relocations. The primary segment is still the 16" Diameter, 0.250" Wall Thickness and 52,000 SMYS in the current report (see DR 14).

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SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-19)

Date Requested: June 30, 2016
Date Responded: July 15, 2016
Amended Response Submitted: April 27, 2017
Second Amended Response Submitted: May 25, 2017

This second corrected and amended response replaces the response to ORA DR-19, Question 7 submitted on July 15, 2016 and the amended response submitted on April 27, 2017 in its entirety.

QUESTION 7:

Please explain the discrepancies in pipeline records between SDG&E's 1968 report on Line 1600 (provided in response to ORA DR-14 Q2) and the L1600 pipe segment data (provided in response to ORA DR-06 Q12).

RESPONSE 7:

The pipeline record provided in ORA DR-14 Q2 was developed in 1968, and the pipeline record provided in the May 22, 2017 Amended Response (and the Corrected and Updated Attachment thereto) to ORA DR-06 Q12 is the current status of Line 1600, which accounts for changes to the pipelines due to various reasons, such as replacement or relocations. The primary segment is still the 16" Diameter, 0.250" Wall Thickness and 52,000 SMYS in the current report (see DR 14). The May 22, 2017 Amended Response to ORA DR-06, Question 12 (and the Corrected and Updated Attachment thereto) also reflects corrections of inaccurate information provided in the original May 12, 2016 Attachment to ORA DR-06, Question 12. The original data was taken from a database that had not been fully updated to reflect information learned from research of historical records and to reflect recent construction activity. The corrected information was previously provided to ORA in: (1) Applicants' August 12, 2016 response to ORA DR 25, Question 1; (2) Applicants' August 4, 2016 email to ORA (Ogeonye Enyinwa, Nathaniel Skinner, Mina Botros, Pearlie Sabino, and Darryl Gruen) attaching an amendment to a document previously provided in response to ORA DR 19, specifically a copy of Applicants' August 2, 2016 amended response to SED DR 3, Q2 and Attachment thereto; and (3) Applicants' July 15, 2016 response to ORA DR 19 (which provided a copy of Applicants' original response to SED DR 3, Q2 and Attachment thereto). Corrections are noted in red in the attachment to the May 22, 2017 Amended Response to ORA DR-06, Question 12.

In addition, the May 22, 2017 Amended Response (and the Corrected and Updated Attachment thereto) to ORA DR-06, Q12 also reflects that the Line 1600 segment for Engineering Station 17-131 was replaced as of October 26, 2016, as ORA previously was informed in Applicants' November 30, 2016 response to ORA DR 51, Q3.

Attachment B-13

Utilities' Response to ORA DR-48, Q1

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-48)

Date Requested: November 9, 2016
Date Responded: November 28, 2016

QUESTION 1:

Subject: Integrity Management

SCG/SDG&E has stated that Line 1600 would be managed under the Distribution Integrity Management Program if derated, rather than under the Transmission Integrity Management Program (SCG/SDG&E Response to ORA DR-36, Q6; and CEA page 62, FN 122).

a) Please provide a copy of the written integrity management plan SCG/SDG&E currently uses as required under 49 Code of Federal Regulations §§ 192.1005 and 192.1007.

b) What specific measures and methods will SCG/SDG&E use to identify and reduce risk on Line 1600 if it is derated?

c) How are these measures different than if Line 1600 is managed under the Transmission Integrity Management Program?

d) Please identify each element of 49 CFR §§ 192.1005 and 192.1007 that would be followed by the specific measures and methods provided in response to question 1b.

e) Please identify each element of 49 CFR §§ 192.1005 and 192.1007 that would not be followed by the specific measures and methods provided in response to question 1b.

f) Even if Line 1600 is derated, please explain if the Transmission Integrity Management Program measures or Distribution Integrity Management Program measures are more or less likely to identify future problems or risks with the maintenance and operations of Line 1600.

RESPONSE 1:

a. Applicants object to this question on the grounds that it is seeks information not relevant to any issue within the scope of this proceeding, which addresses Line 1600, compliance with Public Utilities Code § 958 and D.11-06-017, and whether the Proposed Project best serves the public convenience and necessity. ORA is welcome to schedule an appointment with Applicants to review their DIMP Plan in person.

b. The primary risk reduction measure for Line 1600 will be lowering its operating pressure and MAOP to below 20% SMYS as proposed in this Application. As explained in the Prepared Direct Testimony of Travis Sera (at page 2, Lines 1-3), “lowering the operating pressure on Line 1600 will permanently and significantly reduce exposure to the risk factors associated with operating a 1949 vintage pipeline at a transmission service stress level above 20% SMYS”. Because of its age, Line 1600 possesses inherent qualities (vintage manufacturing practices) that pose higher risk when operated at higher stress levels.

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(A.15-09-013)

(DATA REQUEST ORA-48)

Date Requested: November 9, 2016
Date Responded: November 28, 2016

Mr. Sera's testimony (at page 9, Lines 6-8) also discusses the benefits of lowering operating stress by referencing a USDOT report which states, in part, that "[T]he analyses presented ... show that a 20-percent reduction is almost as good as a test to 1.25 times MAOP... Therefore, for M [manufacturing] defects, it is a permanent demonstration of stability". Additionally, Mr. Sera's testimony (at page 24, Lines 7-9) states that "Lowering the pressure further so that Line 1600 operates below 20% of the SMYS would create an additional safety margin beyond that already implemented by the Utilities and would effectively nullify the risk of rupture." Any subsequent failures would manifest as leaks and would be integrated into the DIMP analysis for appropriate evaluation and action.

In addition to the above risk reduction measure, the routine programs and activities to address risk will continue to be applied to Line 1600. These routine measures are compliant with 49 CFR 192 and include but are not limited to:

- Pipeline markers;
- 811 – Call before you dig program;
- High pressure excavation monitoring and stand by;
- Public Awareness communications;
- Monitoring and maintenance of applied cathodic protection;
- Leak survey;
- Pipeline Patrol;
- Valve maintenance;
- Regulator station maintenance;
- Remote Pressure monitoring;

c. The listing of bulleted inspection and maintenance items outlined in response to Question 1(c) above would be the same. The primary difference would be that TIMP has prescriptive code requirements that must be followed to remain compliant under 49 CFR Subpart O. The TIMP specific requirements are not required, but could still be used if deemed appropriate, within DIMP, 49 CFR Subpart P.

d. The processes and procedures inherent within the Distribution Integrity Management Program include the requirements specified in 49 CFR §§ 192.1005 and 192.1007. These requirements are applied to all pipe, fittings, and components within the DIMP.

e. All DIMP requirements would be followed. There would be no exclusions.

f. Applicants object to this data request as not relevant to the subject matter involved in this proceeding because it is not itself admissible in evidence nor does it appear reasonably calculated to lead to the discovery of admissible evidence.

Attachment B-14

Utilities' Response to ORA DR-24, Q1

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-24)

Date Requested: July 28, 2016
Date Responded: August 11, 2016

QUESTION 1:

In discussing the de-rate of Line 1600 to distribution service, page 15 of Mr. Navin's testimony states "ten regulator stations would no longer be needed between Line 1600 and the distribution system downstream." Page 21 of Mr. Navin's testimony states "The Proposed Project scope includes the de-rating of Line 1600 for continued operation as a distribution asset." The Project Schedule in Attachment VIII shows Line 1600 De-rate Construction beginning the third quarter of year 2020 through the end of the first quarter of 2021 when construction is expected to be completed.

(a) Is it accurate to assume that ongoing O&M expenses on Line 1600 will continue to be incurred until the line is no longer in service as a transmission asset? Please respond first with a yes or no and then state whether Sempra expects to continue to incur the Line 1600 annual O&M expenses on the transmission asset until at least the end of the 2nd quarter of year 2020 based on the project schedule shown in Attachment VIII.

(b) Please provide the continuing amount of annual O&M expenses expected to be incurred on Line 1600 as a transmission asset based on historical data for Line 1600 in the last five years. Please state whether the same amount of annual O&M expense is assumed under the Hydro test Alternative (Line 1600) and the Replace Line 1600 In-Place Alternative. If different, please provide the different O&M expense assumptions and explain the basis for a different assumption.

(c) Please clarify whether your response to item (b) above includes the ten regulator stations that would no longer be needed with the de-rate of Line 1600.

(d) Is it accurate to assume that the annual amount of O&M expenses on Line 1600 as a transmission asset in your response to item (b) will continue to be recovered in existing transmission tariff rates unless Sempra submits a filing to the Commission to have the de-rated line be in service as a distribution asset and the tariffs changed accordingly? Please respond first with a yes or no, and then explain your answer.

(e) Please provide an estimate of the annual amount of O&M costs of the de-rated Line 1600 as a distribution asset that is assumed in the CEA for all alternatives that include the Line 1600 de-rate.

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PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-24)

Date Requested: July 28, 2016
Date Responded: August 11, 2016

(f) Based on your response to items (b) and (e) above, please compare the estimated annual amount of O&M expenses and explain why it is reasonable for the amount of annual O&M expenses to be different between Line 1600 functioning as a transmission asset and as a distribution asset.

(g) Please state whether Sempra currently includes Line 1600 in its implementation of the Transmission Integrity Management Program (TIMP).

(h) When Line 1600 is de-rated to a distribution line function, please state whether Sempra expects to include Line 1600 in its implementation of the Distribution Integrity Management Program (DIMP).

(i) Please state whether the program costs of the TIMP and the DIMP are excluded from the estimates of annual O&M expenses for Line 1600.

<u>RESPONSE 1</u>:

a. Yes. SDG&E and SoCalGas expect to continue to incur the Line 1600 annual O&M expenses on the transmission asset until at least the end of the 2nd quarter of 2020 based on the project schedule shown in Attachment VIII of the Prepared Direct Testimony of Neil Navin.

b. SDG&E does not track O&M by specific pipeline. It is estimated that costs associated with recurring annual O&M activities for Line 1600 total approximately $250,000 to $300,000. This excludes large periodic expenses, such as In Line Inspection (ILI) runs, associated validation activities and follow up repairs. If Line 1600 was to be hydrotested and kept in service, or a new “in-place” line constructed, it is anticipated that similar levels of O&M would continue to be incurred.

c. Yes.

d. Yes; however, SDG&E and SoCalGas do not intend to request a tariff/rate change the instant Line 1600 is reclassified to a distribution asset. Rather, the tariff/rate change would occur in SoCalGas’ and SDG&E’s next Triennial Cost Allocation Proceeding (TCAP) following the reclassification, based on a new embedded cost study.

e. No O&M was assumed for the de-rated Line 1600 in the Cost-Effectiveness Analysis (CEA) for the Proposed Project or any Alternatives. The regular recurring costs to maintain Line 1600 in its current configuration compared to its de-rated configuration are similar and anticipated to be in the $250,000 to $300,000 range annually.

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(DATA REQUEST ORA-24)

Date Requested: July 28, 2016
Date Responded: August 11, 2016

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f. As stated in the responses to 1(b) and 1(e) above, the costs for regular recurring O&M of Line 1600 are anticipated to be similar regardless of the configurations being discussed in this Application. In all scenarios, Line 1600 will still need recurring O&M activities such as: leak patrols; cathodic protection inspection and maintenance; atmospheric corrosion inspection on non-buried components; locate and mark activities; valve inspection and maintenance; inspection and maintenance on pressure control devices; inspection and maintenance of Supervisory and Data Acquisition (SCADA) equipment.

g. Yes.

h. Yes.

i. Yes, TIMP and DIMP costs are excluded from the estimates of annual O&M expenses for Line 1600.

Attachment B-15

Utilities' Response to ORA DR-79, Q1

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-79)

Date Requested: March 22, 2017
Date Responded: April 7, 2017

Subject: Lines 1600

QUESTION 1:

If the capacity of Line 1600 is set at 325 psi, or 20% of SMYS for the majority of segments of the line, how much capacity is contributed to meeting San Diego demand?

RESPONSE 1:

Line 1600 would not contribute to system capacity if the pressure, not capacity, is limited to 325 psig.

Attachment B-16

Utilities' Response to ORA DR-19, Q3

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA-19)

Date Requested: June 30, 2016
Date Responded: July 15, 2016

QUESTION 3:

In response to ORA DR-06, Question 6, SDG&E stated:

> **QUESTION 6:**
> Does SCG/SDG&E solely use 20% or greater Specified Minimum Yield Strength to define transmission versus distribution pipe? If the answer is anything other than an unqualified yes, please explain.
>
> **RESPONSE 6:**
> No. In accordance with 49 CFR 192, SDG&E and SoCalGas define a transmission line as a pipeline segment that meets one of the following criteria:
>
> 1. Produces a hoop stress equivalent to 20% of SMYS or more based on the established maximum allowable operating pressure (MAOP).
> 2. Regardless of the operating stress level, transports gas within a storage field for the purpose of well injection or withdrawal, and is not a gathering line. Injection piping ends and withdrawal piping begins at the respective block valves nearest the wellhead used to control or isolate flow to and from the individual well.
> 3. Transports gas to a large volume customer that is not downstream of a distribution center. A distribution center is the point at which gas supply and gas delivery are demarcated by a block valve(s).

a. By each of the three categories, provide the percentage and total number of transmission miles that SDG&E defines under each criteria.

b. Provide SDG&E's criteria for determining whether a pipeline is identified as transmission under (1) hoop stress, or (3) large volume customer.

c. Are any of the customers connected to Line 1600 "large volume customers"? If they are, what would prevent SDG&E or SoCalGas from changing the definition of Line 1600 back to transmission if it is derated? Are there any operational restrictions? Please explain.

d. If Line 1600 is downrated, would any of the large volume customers identified in response to ORA DR-06 Q5 now be served by the distribution system? Would the rates they pay change since they would be served by the distribution system change? Please explain.

e. For questions a-d above, if SoCalGas uses any different definitions, please provide them and explain.

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(DATA REQUEST ORA-19)

Date Requested: June 30, 2016
Date Responded: July 15, 2016

RESPONSE 3:

a. SDG&E defines 100% of the transmission miles by the 1st criteria: Produces a hoop stress equivalent to 20% of SMYS or more based on the established maximum allowable operating pressure (MAOP). Note that the Department of Transportation (DOT) definition of transmission pipelines differs from the definition used for customer rate determination, however in the SDG&E service territory, at this time all DOT transmission lines are also classified as transmission lines for customer rates.

b. For SDG&E all transmission pipelines are defined using (1) hoop stress, since SDG&E defines the term distribution center to be "the transition point at which gas supplies from an Intrastate, Interstate or International pipeline, a California Producer, or a company gas storage field, are transferred into a transmission or distribution pipeline system".

c. Yes, large volume customers are connected to Line 1600. However, as provided in part (b) above the definition of Distribution Center as defined by SDG&E avoids the need to track large volume customers. This allows for a consistent application of the hoop stress definition across the system and avoids pipelines changing DOT designation due to the presence of a large volume customer. Once the pipeline is de-rated, the presence of a large volume customer will not affect the determination of Distribution since it will be operating below the 20% SMYS threshold.

d. As noted the DOT definition of transmission pipelines differs from the definition used for customer rate determination. SDG&E has not yet determined whether this pressure change will translate to moving the customer rate determination. Note that electric generation (EG) customers with average annual usage of 50 million therms or greater are on the Transmission Level Service (TLS) rate, independent of the designation of the pipeline from which they are served.

e. The definition and explanations provide for questions a-d above are applicable to SoCalGas with the exception that SoCalGas operators storage fields within its service territory, therefore the (3) definition of transmission is also used.

Attachment C

ORA Responses to Utilities' Data Requests

Attachment C-1

ORA Response to Utilities' DR-11, Q1 & Q2

ORA

Office of Ratepayer Advocates
California Public Utilities Commission

505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-2544
Fax: (415) 703-2057

http://ora.ca.gov

ORA DATA REQUEST RESPONSE

A.15-09-013: SoCalGas/SDG&E
LINE 1600 / LINE 3602 PSRP

Date: May 30, 2017

To:	**Shirley Amrany** Regulatory Case Manager	Phone: [redacted] Email: [redacted]
	Yvonne Mejia	Phone: Email: [redacted]
	Allen Trial Attorney for SoCalGas/SDG&E	Phone: Email: [redacted]
	Richard Raushenbush Attorney for SoCalGas/SDG&E	Phone: Email: [redacted]
From:	**Oge Enyinwa** Project Coordinator	Phone: Email: [redacted]
	Nathaniel Skinner Witness, ORA-02	Phone: [redacted] Email: [redacted]
	Mina Botros Witness, ORA-02	Phone: [redacted] Email: [redacted]
	Darryl Gruen Attorney for ORA	Phone: Email: [redacted]

Re: Data Request No. SCG/SDG&E 11 to ORA
Date Request Received: May 23, 2017
Responses Due: May 30, 2017

The following is ORA's response to SCG/SDG&E's data request. If you have any questions, please contact the responder at the phone number and/or email address shown above.

<u>DATA REQUESTS</u>

DATA REQUEST NO. 1

<u>ORA-02 at page 15, line 14 states: "Specifically, the design pressure of Line 1600's weakest pipeline segments would operate at 24% SMYS, [footnote omitted] and the next weakest segments would operate at approximately 22% SMYS [footnote omitted]." Assuming the data provided in Applicants' May 22, 2017 Corrected and Updated Response to ORA DR-6, Q12 to be correct, and utilizing it to respond to this data request, please state the design pressure and % of SMYS of the weakest pipeline segment in Line 1600 determined in accordance with 49 CFR Part 192, Subparts C and D.</u>

Consistent with the discussion in the meet and confer with SoCalGas/SDG&E on May 17, 2017 regarding this data request, ORA understands this question to be hypothetically asking, *If* the <u>data provided in Applicants' May 22, 2017 Corrected and Updated Response to ORA DR-6, Q12 were correct, please state the design pressure and % of SMYS of the weakest pipeline segment in Line 1600 determined in accordance with 49 CFR Part 192, Subparts C and D.</u> Also consistent with the discussion in the meet and confer with SoCalGas/SDG&E on May 17, 2017, ORA does not currently accept as correct the information provided in Applicant's April 27, 2017 Corrected and Updated Response to ORA DR-6, Q12, nor in Applicant's May 22, 2017 Corrected and Updated Response which was provided subsequently to the May 17, 2017 meet and confer. As ORA expressed during the May 17, 2017 meet and confer, before ORA can consider accuracy of the April 27, 2017 Corrected and Updated Response and now the May 22, 2017 Corrected and Updated Response to ORA DR-6, Q12, ORA needs to receive from Applicants a complete and accurate answer to ORA Data Request 84. ORA may also require additional follow up discovery to SoCalGas/SDG&E's response to ORA Data Request 84. ORA puts Applicants on notice that failure to of Applicants to fully cooperate with ORA's discovery regarding the discrepancies between Applicants initial response to ORA DR6, Q12, and Applicants' April 27, 2017 Corrected and Updated Response to ORA DR-6, Q12 and Applicants' May 22, 2017 Corrected and Updated Response to ORA DR-6, Q12 may impair ORA's ability to assess the veracity of each of these data responses. If, despite the discrepancies between the initial and updated responses to ORA DR6, Q12, ORA can confirm that the data provided in both the April 27, 2017 Corrected and Updated Response and the May 22, 2017 Corrected and Updated Response to ORA DR-6, Q12 is complete and correct, then ORA provides the response in the next paragraph. ORA's response to this question is subject to update based on ORA's analysis of the response SoCalGas/SDG&E provides to ORA data request 84 and follow up discovery, which regards the updates made by SoCalGas/SDG&E to ORA DR-6, Q12. ORA also puts SoCalGas/SDG&E on notice that ORA deems reference or quotation to only one excerpt of this data response an incomplete reference and a mischaracterization of ORA's response to this data request.

Assuming the second updated data response from May 22, 2017 is accurate, the weakest segments of Line 1600 would have a MAOP (without class location) of 1625 psig, which is reduced to 812.5 psig in areas with a Class Location 3. In requesting the percentage SMYS, ORA assumes SoCalGas/SDG&E mean at a MAOP of 320 psig. Under this assumption the weakest segments would operate at a 19.7% SMYS (320 psig / 1625 psig). Under ORA's proposed MAOP of 325 psig, the weakest segments would operate at a 20.0% SMYS (325 psig / 1625 psig).

DATA REQUEST NO. 2

ORA-02 at page 16, lines 6 and 7 states that "By ORA's calculations, the approximate distance of the segments exceeding 20% SMYS with an MAOP of 320 psig is approximately 0.5 miles." Assuming the data provided in Applicants' May 22, 2017 Corrected and Updated Response to ORA DR-6, Q12 to be correct, and utilizing it to respond to this data request, please state the number of miles of Line 1600 that exceed 20% of SMYS. Please provide ORA's workpapers that support this response and identify the person responsible for preparing the workpapers and this response.

Consistent with the discussion in the meet and confer with SoCalGas/SDG&E on May 17, 2017 regarding this data request, ORA understands this question to be hypothetically asking, *If* the data provided in Applicants' May 22, 2017 Corrected and Updated Response to ORA DR-6, Q12 were correct, and utilizing that data, please state the number of miles of Line 1600 that exceed 20% of SMYS. Please provide ORA's workpapers that support this response and identify the person responsible for preparing the workpapers and this response. Also consistent with the discussion in the meet and confer with SoCalGas/SDG&E on May 17, 2017, ORA does not currently accept as correct the information provided in Applicant's April 27, 2017 Corrected and Updated Response to ORA DR-6, Q12, nor in Applicant's May 22, 2017 Corrected and Updated Response which was provided subsequently to the May 17, 2017 meet and confer. As ORA expressed during the May 17, 2017 meet and confer, before ORA can consider accuracy of the April 27, 2017 Corrected and Updated Response and now the May 22, 2017 Corrected and Updated Response to ORA DR-6, Q12, ORA needs to receive from Applicants a complete and accurate answer to ORA Data Request 84. ORA may also require additional follow up discovery to SoCalGas/SDG&E's response to ORA Data Request 84. ORA puts Applicants on notice that failure to of Applicants to fully cooperate with ORA's discovery regarding the discrepancies between Applicants initial response to ORA DR6, Q12, and Applicants' April 27, 2017 Corrected and Updated Response to ORA DR-6, Q12 and Applicants' May 22, 2017 Corrected and Updated Response to ORA DR-6, Q12 may impair ORA's ability to assess the veracity of each of these data responses. If, despite the discrepancies between the initial and updated responses to ORA DR6, Q12, ORA can confirm that the data provided in both the April 27, 2017 Corrected and Updated Response and the May 22, 2017 Corrected and Updated Response to ORA DR-6, Q12 is complete and correct, then ORA provides the response in the next paragraph. ORA's response to this question is subject to update based on ORA's analysis of the response SoCalGas/SDG&E provides to ORA data request 84 and follow up discovery, which regards the updates made by SoCalGas/SDG&E to ORA DR-6, Q12. ORA also puts SoCalGas/SDG&E on notice that ORA deems reference or quotation to only one excerpt of this data response an incomplete reference and a mischaracterization of ORA's response to this data request.

Based on the response to data request 1, above, there would be 0 miles of Line 1600 which exceed 20% SMYS if operated at 320 psig. As the second updated values provided in the May 22, 2017 Corrected and Updated Response to the April 27, 2017 Corrected and Updated Response to the May 12, 2016 Response to ORA data request 06, Q12 are equal to or greater than the values provided in response to SCG/SDG&E Data Request 10, ORA refers SoCalGas/SDG&E to the workpaper provided in response to that data request.

Attachment C-2

ORA Response to Utilities' DR-10, Q3

ORA

Office of Ratepayer Advocates
California Public Utilities Commission

505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-2544
Fax: (415) 703-2057

http://ora.ca.gov

ORA DATA REQUEST RESPONSE
CONFIDENTIAL

A.15-09-013: SoCalGas/SDG&E
LINE 1600 / LINE 3602 PSRP

Date: May 19, 2017

To:	**Shirley Amrany** Regulatory Case Manager	Phone: [redacted] Email: [redacted]
	Yvonne Mejia	Phone: Email: [redacted]
	Allen Trial Attorney for SoCalGas/SDG&E	Phone: Email: [redacted]
	Richard Raushenbush Attorney for SoCalGas/SDG&E	Phone: Email: [redacted]
From:	**Oge Enyinwa** Project Coordinator	Phone: Email: [redacted]
	Nathaniel Skinner Witness, ORA-02	Phone: [redacted] Email: [redacted]
	Mina Botros Witness, ORA-02	Phone: [redacted] Email: [redacted]
	Darryl Gruen Attorney for ORA	Phone: Email: [redacted]

Re: **Data Request No. SCG/SDG&E 10 to ORA**
Date Request Received: May 17, 2017
Responses Due: May 24, 2017

The following is ORA's response to SCG/SDG&E's data request. If you have any questions, please contact the responder at the phone number and/or email address shown above.

3. <u>Please confirm that the design pressure for Line 1600 under 49 CFR Part 192 is defined by an equation in 49 CFR § 192.105. If ORA does not so confirm, please explain the factual basis for ORA's response, produce any documents supporting ORA's response, and identify the person(s) responsible for drafting the response.</u>

ORA confirms that the design pressure for Line 1600 is defined by an equation in 49 CFR 192.105. ORA has used, and understands that SoCalGas/SDG&E has also used, the equation in 49 CFR 192.105 in calculating the design pressure of Line 1600. 49 CFR 192.105 is provided below.

§192.105 Design formula for steel pipe.

(a) The design pressure for steel pipe is determined in accordance with the following formula:

$P = (2\ St/D) \times F \times E \times T$

P = Design pressure in pounds per square inch (kPa) gauge.

S = Yield strength in pounds per square inch (kPa) determined in accordance with §192.107.

D = Nominal outside diameter of the pipe in inches (millimeters).

t = Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with §192.109. Additional wall thickness required for concurrent external loads in accordance with §192.103 may not be included in computing design pressure.

F = Design factor determined in accordance with §192.111.

E = Longitudinal joint factor determined in accordance with §192.113.

T = Temperature derating factor determined in accordance with §192.115.

(b) If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section if the temperature of the pipe exceeds 900 °F (482 °C) at any time or is held above 600 °F (316 °C) for more than 1 hour.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-47, 49 FR 7569, Mar. 1, 1984; Amdt. 192-85, 63 FR 37502, July 13, 1998]

Attachment C-3

ORA Response to Utilities' DR-6, Q7 and Q16

ORA

Office of Ratepayer Advocates
California Public Utilities Commission

ELIZABETH ECHOLS
Director

505 Van Ness Avenue
San Francisco, California 94102
Tel: 415-703-2381
Fax: (415) 703-2057

http://ora.ca.gov

ORA Response to SDG&E/SoCalGas Data Request SCG/SDG&E-ORA-DR-05
Southern California Gas Company / San Diego Gas & Electric
CPCN for the Pipeline Safety and Reliability Project (L3602 / L1600)
Proceeding, A.15-09-013

Origination Date: April 28, 2017

Due Date: May 12, 2017

Responses Date: May 12, 2017

Revised Date: N/A

To: Shirley Amrany
Regulatory Case Manager
555 West 5th Street
Los Angeles, CA 90013
Telephone: [redacted]
E-mail: [redacted]

Yvonne Mejia
Email: [redacted]

Allen Trial, Counsel
Email: [redacted]

Richard Raushenbush, Counsel
Email: [redacted]

From: Oge Enyinwa, Project Coordinator
Office of Ratepayer Advocates
505 Van Ness Avenue,
San Francisco, CA 94102
Email: [redacted]

Response by: Nathaniel Skinner

Phone: [redacted]
Email: [redacted]

Mina Botros
[redacted]
Email: [redacted]

ORA Counsel Darryl Gruen
Email: [redacted]

Data Request No: SCG/SDG&E-ORA-DR-06
Exhibit Reference: ORA-02 – Ch. 2 Direct Testimony – N Skinner and M Botros
Subject: Data Request Response

The following is ORA's response to SCG/SDG&E's data request. If you have any questions, please contact the responder at the phone number and/or email address shown above.

DATA REQUEST NO. 7

Please admit that Line 1600 does not contain any segments of cast iron pipe. If ORA does not so admit, please explain the factual basis for ORA's response, produce any documents supporting ORA's response, and identify the person(s) responsible for drafting the response.

ORA RESPONSE TO SCG/SDG&E DATA REQUEST NO. 7

ORA objects to the posture of this question asking for an admission. ORA is not providing an admission in its response to this question. ORA hereby puts Applicants on notice that any suggestion on Applicants' part in rebuttal testimony or elsewhere that states or in any way suggests ORA admits that, "Line 1600 does not contain any segments of cast iron pipe" will be deemed by ORA as a mischaracterization of ORA's position in testimony, and a mischaracterization of ORA's response to discovery. ORA further reserves the right to clarify any testimony from Applicants that mischaracterizes ORA as providing an admission regarding this response, including quotation and citation of this data response. Notwithstanding these objections, ORA provides the following answer.

ORA has reviewed materials regarding the pipeline, and based on the materials provided by SoCalGas/SDG&E, agrees that Line 1600 does not appear to contain any segments made from cast iron.

DATA REQUEST NO. 16

Given the 68 year operating history of Line 1600 as a transmission line at pressures consistently exceeding 500 psig, and given that Resolution No. SED-1 currently allows the pipeline to be operated at pressures up to 512 psig, and considering the information provided in Applicants response to ORA DR 14 Question 2 regarding historical operating pressures for Line 1600, please respond to the following. For each subsection below, please state all facts that support your response, produce all workpapers and documents that support your response, and identify the person(s) that prepared the response.

a. Please describe and explain the reasons for testing line 1600 with gas at a pressure of 487.5 psig.

b. Describe what will be accomplished by said test, including but not limited to, what new information will be learned by completing this test.

c. Describe how this test will provide useful and meaningful information regarding the safety of Line 1600. Describe the useful and meaningful information that will be provided.

d. State whether a test at this pressure will expose potentially critical defects in the pipeline. Describe those defects and explain why those defects haven't already been exposed at current transmission level operating pressures.

e. Describe why performing a gas test of Line 1600 at 487.5 psig is a good value for SDG&E's customers.

ORA RESPONSE TO SCG/SDG&E DATA REQUEST NO. 16:

a. ORA recommends testing Line 1600 with gas at a pressure of 487.5 psig in order to maintain compliance with PU Code Section 958 which requires pressure testing of natural gas transmission pipelines, and to slightly exceed the test pressure required by 49 CFR Section 192.619 to validate an MAOP of 325 psig, which requires pressure testing at a pressure of at least 1.4x the intended MAOP of the pipeline for a pipeline installed before November 12, 1970 in class 3 and 4 locations. 487.5 psig is consistent with a 1.5x test supporting ORA's recommended MAOP of 325 psig, and consistent with the requirements under 49 CFR 192 Subpart J and 192.619 for pressure tests in Class 3 and 4 locations. See generally Ex. ORA-02, and specifically pp. 8-10. ORA recommends a pressure test with gas as it may address the difficulties identified by SoCalGas/SDG&E with water, in its February 2017 Supplemental Testimony, Chapter 18, Scoping Memo Issue 17, Scoping Memo Issue 17: "Is it feasible, reasonable/cost-effective and prudent to pressure test Line 1600 and return it to transmission service (e.g., 512 psig) without any changes to the SDG&E gas system?"

Since Line 1600 was installed prior to 1970, it could alternatively be tested to 1.4x the ORA recommended 325 psig, which would be commensurate with a 455 psig test. These test pressures are all below the current MAOP of Line 1600, which is 512 psig.

b. The purpose of the pressure test is to ensure compliance with 49 CFR 192.619, 49 CFR Subpart J, and PU Code Section 958.

c. The purpose of the pressure test is to ensure compliance with 49 CFR 192.619, 49 CFR Subpart J, and PU Code Section 958, which are minimum safety requirements.

d. Given the previous operating pressures at or exceeding 512 psig, ORA does not expect critical flaws to be exposed. However, as stated in ORA's testimony, a test is needed to comply with federal and state requirements.

e. ORA recommends testing "Line 1600 at 487.5 psig" as a "good value for SDG&E's customers" because it ensures that Line 1600 is compliant with federal and state safety requirements. Given that PU Code Section 958 requires testing or replacing Line 1600 as a transmission line (given the errors identified in the SoCalGas/SDG&E proposal to derate Line 1600 to 320 psig identified in ORA-02), 49 CFR 192.619(a) sets forth pressure testing requirements, which a test to 487.5 complies with. While 49 CFR 192.619(c) allows an exemption from pressure testing transmission and distribution pipelines installed prior to 1970 that are in good condition and have not had class location changes, ORA recommends testing so that the Commission, ratepayers, and the public are afforded the safety that these requirements mandate, and that SoCalGas/SDG&E is ensured to be compliant with federal and state requirements. Also, if SoCalGas/SDG&E were found non-compliant, ORA anticipates that far more ratepayer and Commission resources would be expended on proceedings investigating such non-compliance than if SoCalGas/SDG&E were to seek a waiver (due to previous operating pressures) and/or test Line 1600.

END OF RESPONSE

Attachment C-4

ORA Response to Utilities' DR-09, Q3 and Q4

ORA

Office of Ratepayer Advocates
California Public Utilities Commission

505 Van Ness Avenue
San Francisco, California 94102
Tel: 415-703-2381
Fax: (415) 703-2057

http://ora.ca.gov

ORA Response to SDG&E/SoCalGas Data Request SCG/SDG&E-ORA-DR-09
Southern California Gas Company / San Diego Gas & Electric
CPCN for the Pipeline Safety and Reliability Project (L3602 / L1600)
Proceeding, A.15-09-013

Origination Date: May 10, 2017

Due Date: May 24, 2017

Responses Date: May 24, 2017

Revised Date: N/A

To: Shirley Amrany
Regulatory Case Manager
[redacted]
Telephone: [redacted]
E-mail: [redacted]

Yvonne Mejia
Email: [redacted]

Allen Trial, Counsel
Email: [redacted]

Richard Raushenbush, Counsel
Email: [redacted]

From: Oge Enyinwa, Project Coordinator
Office of Ratepayer Advocates
[redacted]
Email: [redacted]

Response by: Nathaniel Skinner
Phone: [redacted]
Email: [redacted]

ORA Counsel Darryl Gruen
Email: [redacted]

Data Request No: SCG/SDG&E-ORA-DR-09
Exhibit Reference: ORA-02 – Ch. 2 Direct Testimony – N Skinner and M Botros
Subject: Data Request Response

The following is ORA's response to SCG/SDG&E's data request. If you have any questions, please contact the responder at the phone number and/or email address shown above.

DATA REQUEST NO. 3

In response to SDG&E/SoCalGas Data Request #5, Question 7, ORA refers to SoCalGas/SDG&E's response to ORA Data Request 48, Question 1. In part, with emphasis added, that question and response provide:

> QUESTION 1:
> Subject: Integrity Management
> SCG/SDG&E has stated that Line 1600 would be managed under the Distribution Integrity Management Program if derated, rather than under the Transmission Integrity Management Program (SCG/SDG&E Response to ORA DR-36, Q6; and CEA page 62, FN 122).
> …
> b) What specific measures and methods will SCG/SDG&E use to identify and reduce risk on Line 1600 if it is derated?
>
> c) How are these measures different than if Line 1600 is managed under the Transmission Integrity Management Program?
>
> d) Please identify each element of 49 CFR §§ 192.1005 and 192.1007 that would be followed by the specific measures and methods provided in response to question 1b.
>
> e) Please identify each element of 49 CFR §§ 192.1005 and 192.1007 that would not be followed by the specific measures and methods provided in response to question 1b.
>
> RESPONSE 1:
> …
> b. The primary risk reduction measure for Line 1600 will be lowering its operating pressure and MAOP to below 20% SMYS as proposed in this Application. As explained in the Prepared Direct Testimony of Travis Sera (at page 2, Lines 1-3), "lowering the operating pressure on Line 1600 will permanently and significantly reduce exposure to the risk factors associated with operating a 1949 vintage pipeline at a transmission service stress level above 20% SMYS". Because of its age, Line 1600 possesses inherent qualities (vintage manufacturing practices) that pose higher risk when operated at higher stress levels.
>
> Mr. Sera's testimony (at page 9, Lines 6-8) also discusses the benefits of lowering operating stress by referencing a USDOT report which states, in part, that "[T]he analyses presented ... show that a 20-percent reduction is almost as good as a test to 1.25 times MAOP... Therefore, for M [manufacturing] defects, it is a permanent demonstration of stability". Additionally, Mr. Sera's testimony (at page 24, Lines 7-9) states that "Lowering the pressure further so that Line 1600 operates below 20% of the SMYS would create an additional safety margin beyond that already implemented by the Utilities and would effectively nullify the risk of rupture." Any subsequent failures would manifest as leaks and would be integrated into the DIMP analysis for appropriate evaluation and action.

In addition to the above risk reduction measure, the routine programs and activities to address risk will continue to be applied to Line 1600. These routine measures are compliant with 49 CFR 192 and include but are not limited to:

- Pipeline markers;
- 811 – Call before you dig program;
- High pressure excavation monitoring and stand by;
- Public Awareness communications;
- Monitoring and maintenance of applied cathodic protection;
- Leak survey;
- Pipeline Patrol;
- Valve maintenance;
- Regulator station maintenance;
- Remote Pressure monitoring;

c. The listing of bulleted inspection and maintenance items outlined in response to Question 1(c) above would be the same. The primary difference would be that TIMP has prescriptive code requirements that must be followed to remain compliant under 49 CFR Subpart O. The TIMP specific requirements are not required, but could still be used if deemed appropriate, within DIMP, 49 CFR Subpart P.

d. The processes and procedures inherent within the Distribution Integrity Management Program include the requirements specified in 49 CFR §§ 192.1005 and 192.1007. These requirements are applied to all pipe, fittings, and components within the DIMP.

e. All DIMP requirements would be followed. There would be no exclusions.

With the above ORA Data Request and Applicants' response in mind, please:

a. State any safety measures not found in the bulleted list provided in Applicants' response to ORA DR 48, Q.1b that ORA contends should be applied to Line 1600 if de-rated to a MAOP of 320 psig.

ORA has made and continues to make a good faith effort to provide a detailed set of safety measures accompany Applicants' proposed project in response to SoCalGas/SDG&E Data Request 5, Question 7, and to this question. It is not ORA's job to identify every last safety measure that needs to accompany Applicants' own proposed project. The onus is on Applicants to propose a comprehensive set of safety measures accompanying its own project for intervening parties and the Commission to consider; not for parties to identify an exhaustive list of safety measures for Applicants. Notwithstanding this concern, ORA answers as follows:

Given that Line 1600 remains a transmission line if operated at 320 psig as proposed by applicants, and based on ORA's response to data request 5 question 7, applicants have not specifically identified measures required to meet:

1. 49 CFR Section 192.917(e)(2) regarding cyclic fatigue;

2. 49 CFR Section 192.917(e)(4) regarding ERW pipeline;
3. Any difference in assessment schedules between DIMP and TIMP assessments and their impact on safety;
4. The frequency of leak surveys applicants would conduct on Line 1600 if operated as a distribution line, and their impact on safety.
5. SoCalGas/SDG&E has stated only that there is the "expectation is that SDG&E will continue with integrity inspections of Line 1600 in DIMP" (SoCalGas/SDG&E response to ORA data request 23, question 5c), ORA and the Commission cannot otherwise ensure that SoCalGas/SDG&E will continue will integrity inspections unless mandated by the Commission; and
6. All other measures necessary on Line 1600 for Applicants to operate it in compliance with California Public Utilities Code Section 451.

<u>b. For each safety measure identified in response to subpart (a) above, state whether it is required by 49 CFR § 192.917.</u>

The measures identified above are not solely required for 49 CFR 192.917. These safety measures are required under 49 CFR 192 Subpart O. The first two items are required under 49 CFR 192.917, while the second two are more generally addressed under Subparts O and P. The last requirement, as SoCalGas/SDG&E have stated, is not required under 49 CFR 192 Subpart P (DIMP), which only more generally requires the Integrity Management Program to be "an overall approach by an operator to ensure the integrity of its gas distribution system" (49 CFR 192.1001).

Also, California Public Utilities Code Section 451 is much broader than 49 CFR Section 192.917, stating in part,

> "Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, including telephone facilities, as defined in Section 54.1 of the Civil Code, as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

In order to comply with Section 451 of the California Public Utilities Code, SoCalGas and SDG&E, not ORA, are required to take the necessary safety measures, including, but not necessarily limited to those in the aforementioned list in order to promote the safety, health, comfort, and convenience of their patrons, employees, and the public.

<u>c. For each safety measure identified in response to subpart (a) above, state the reasons that ORA contends it should be applied to Line 1600 if de-rated to a MAOP of 320 psig.</u>

ORA contends that Applicants should follow minimum safety requirements, and since these requirements exist under 49 CFR 192, Applicants should follow them. Applicants have also identified numerous concerns regarding the safety and integrity of Line 1600, including but not limited to pipeline integrity and ERW pipe.

Regarding Section 451 of the California Public Utilities Code, SoCalGas and SDG&E are required to take all necessary safety measures, including, but not necessarily limited to those in the aforementioned list in order to promote the safety, health, comfort, and convenience of their patrons, employees, and the public.

d. For each safety measure identified in response to subpart (a) above, explain whether it would increase the safety of Line 1600 if de-rated to a MAOP of 320 psig and, if so, why.

Regarding federal code, ORA has not conducted an assessment of how each measure impacts safety as they are minimum requirements.

Regarding Section 451 of the California Public Utilities Code, ORA expects that SoCalGas/SDG&E take all necessary measures to follow that requirement at all times, regardless of the MAOP on the line.

DATA REQUEST NO. 4

California Public Utilities Code § 958(a) provides: "Each gas corporation shall prepare and submit to the commission a proposed comprehensive pressure testing implementation plan for all intrastate transmission lines to either pressure test those lines or to replace all segments of intrastate transmission lines that were not pressure tested or that lack sufficient details related to performance of pressure testing. …" Does ORA contend that California Public Utilities Code § 958 requires that a pipeline classified as "Distribution Line" under 49 CFR § 192.3 must be pressure tested or replaced if it has not been pressure tested previously?

No. ORA does not contend that PU Code Section 958 "requires that a pipeline classified as 'Distribution Line' under 49 CFR § 192.3 must be pressure tested or replaced if it has not been pressure tested previously". However, for Line 1600, SoCalGas/SDG&E have omitted the bottom half of the adopted PSEP Decision Tree (Attachment 1 to D.14-06-007), where it specifically stated:

> 5) L#1600 - 54 miles of existing L#1600 to be TFI'd (Amended Workpapers, WP-IX-1-43). After 54 new miles installed in Phase 1B (Amended Workpapers, WP-IX-1-34), then 45 miles of existing L#1600 will be pressure tested in Phase 1B (Amended Workpapers, WP-IX-1-17)

ORA understands reference to "existing L#1600 will be pressure tested" to mean that SoCalGas/SDG&E would pressure test Line 1600, as the transmission line that existed at the time the Decision Tree was adopted by D.14-06-007. Nothing in Attachment 1 to D.14-06-007 states or suggests that Line 1600 would be converted to a distribution line. Also, nothing in item 5 says that if Line 1600 were converted to a distribution line, that SoCalGas/SDG&E would not test it.

Attachment C-5

ORA Response to Utilities' DR-04, Q1 and Q6

ORA

Office of Ratepayer Advocates
California Public Utilities Commission

505 Van Ness Avenue
San Francisco, California 94102
Tel: 415-703-2381
Fax: (415) 703-2057

http://ora.ca.gov

ORA Updated Response to SDG&E/SoCalGas Data Request SCG/SDG&E-ORA-DR-04
Southern California Gas Company / San Diego Gas & Electric
CPCN for A.15-09-013

Origination Date: April 21, 2017

Due Date: May 5, 2017

Responses Date: May 5, 2017

Revised Date: May 18, 2017

To: Shirley Amrany
Regulatory Case Manager
[redacted]
Telephone:[redacted]
E-mail: [redacted]

Yvonne Mejia
Email: [redacted]

Allen Trial, Counsel
Email:[redacted]

Richard Raushenbush, Counsel
Email: [redacted]

From: Oge Enyinwa, Project Coordinator
[redacted]
Email: [redacted]

Response by: Nathaniel Skinner
Phone: [redacted]
Email: [redacted]

Mina Botros
[redacted]
Email: [redacted]

ORA Counsel Darryl Gruen
Email: [redacted]

Data Request No: SCG/SDG&E-ORA-DR-04
Exhibit Reference: ORA-02 – Ch. 2 Direct Testimony – N Skinner and M Botros
ORA-03 – Ch. 3 Direct Testimony – M Botros
Subject: Data Request Response

The following is ORA's updated response to SCG/SDG&E's data request. If you have any questions, please contact the responder at the phone number and/or email address shown above.

Changes are marked in bold underline (additions) or strikeout (deletions).

<u>DATA REQUEST NO. 1</u>

<u>ORA-2 at page 4-5 states: "As an additional safety enhancement to the proposed derating of Line 1600, ORA recommends that at each point where a line with a MAOP greater than 325 psig connects to Line 1600, the Applicants be required to install overpressure protection equipment consisting of: 1) a pressure regulator; 2) two monitoring valves; and 3) a pressure relief valve. These measures will ensure that all four devices would have to fail before Line 1600 would be over-pressurized by gas coming through such a connection point." (Footnotes omitted). With that ORA testimony in mind, please respond to the following questions:</u>

f. <u>Please admit that 49 CFR § 192.195 and § 192.197 do not require more than two forms of over pressure protection for high pressure pipelines. If ORA does not so admit, please state the factual basis, and produce any documents, that support your response, and identify the individual(s) responsible for preparing your response.</u>

ORA objects to this question as overbroad and vague in its use of the term "high pressure pipelines". ORA further objects to the use of the term "high pressure pipelines" as outside the scope of ORA's testimony, and assuming facts not in evidence. Exhibit ORA-02's summary of recommendations states, "Line 1600, if derated to 320 psig, as proposed by Applicants, is nevertheless required to remain a *transmission line* pursuant to federal safety requirements. [footnote omitted]" (Emphasis added.)

Notwithstanding these objections, ORA answers as follows:

49 CFR 192.195 and 192.197, as part of 49 CFR 192, are the "minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).", as defined in 49 CFR 192.1.

Under both the Applicants and ORA's proposal, Line 1600 remains a transmission line. Accordingly, 49 CFR 192.195(a) applies, which states:

(a) *General requirements.* Except as provided in §192.197, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of §§192.199 and 192.201.

The requirements of 49 CFR 192.195 do not state a specific number of over pressure protection devices, but its use of the plural term "devices" requires more than one (the specific language reads "pressure relieving or pressure limiting devices that meet the requirements of 192.199 and 192.201". **<u>While the requirement of 49 CFR Section 192.195 does not specify the number of "devices" required, it also does not limit the number of devices to be used. While ORA understands the SoCalGas/SDG&E two-valve proposal could satisfy the requirement to use</u>**

<u>multiple "devices", ORA maintains that given the unique facts regarding the age, condition and overpressurization history of Line 1600 in this case, ORA's recommendation to place four such devices at each connection point between a high pressure line and Line 1600 is not inconsistent with the requirements of 49 CFR Section 192.195.</u>

The requirements of 49 CFR 192.197 apply to "high pressure distribution systems." Line 1600 as proposed by Applicants is not a high pressure distribution system and therefore 49 CFR 192.197 does not apply. Even if the assertion by SoCalGas/SDG&E is accepted that Line 1600 would be a high pressure distribution system if operated at 320 psig, 192.197 still does not require there to be only two over protection devices, and 49 CFR 192 is the "minimum safety requirements for pipeline facilities and the transportation of gas" as defined in 49 CFR 192.1.

49 CFR 192.201, however, requires for pipelines, which operate at or above 60 psig, that "pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower." Additionally, 49 CFR 192.201 requires: "(b) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower."

For reference, quotes of 49 CFR §§192.195-192.201 are provided below.

<u>§192.195 Protection against accidental overpressuring.</u>

(a) *General requirements.* Except as provided in §192.197, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of §§192.199 and 192.201.

(b) *Additional requirements for distribution systems.* Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must—

(1) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and

(2) Be designed so as to prevent accidental overpressuring.

§192.197 Control of the pressure of gas delivered from high-pressure distribution systems.

(a) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less and a service regulator having the following characteristics is used, no other pressure limiting device is required:

(1) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances.

(2) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.

(3) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.

(4) Pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter.

(5) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(6) A self-contained service regulator with no external static or control lines.

(b) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less, and a service regulator that does not have all of the characteristics listed in paragraph (a) of this section is used, or if the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

(c) If the maximum actual operating pressure of the distribution system exceeds 60 p.s.i. (414 kPa) gage, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

(1) A service regulator having the characteristics listed in paragraph (a) of this section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 p.s.i. (414 kPa) gage. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 p.s.i. (414 kPa) gage or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts, if the pressure on the inlet of the service regulator exceeds the set pressure (60 p.s.i. (414 kPa) gage or less), and remains closed until manually reset.

(2) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.

(3) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 p.s.i. (862 kPa) gage. For higher inlet pressures, the methods in paragraph (c) (1) or (2) of this section must be used.

(4) A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 7, 1970; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§192.199 Requirements for design of pressure relief and limiting devices.

Except for rupture discs, each pressure relief or pressure limiting device must:

(a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;

(b) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

(c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;

(d) Have support made of noncombustible material;

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;

(f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

(g) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and

(h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§192.201 Required capacity of pressure relieving and limiting stations.

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

(1) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(2) In pipelines other than a low pressure distribution system:

(i) If the maximum allowable operating pressure is 60 p.s.i. (414 kPa) gage or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;

(ii) If the maximum allowable operating pressure is 12 p.s.i. (83 kPa) gage or more, but less than 60 p.s.i. (414 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i. (41 kPa) gage; or

(iii) If the maximum allowable operating pressure is less than 12 p.s.i. (83 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

(b) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

(c) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

DATA REQUEST NO. 6

ORA-3 at page 6 states: "ORA anticipates that purchasing gas through Otay Mesa receipt point (Alternative E), would be immensely less expensive than constructing a new pipeline." (Footnote omitted) With respect to the purchase of gas through Otay Mesa assumed in such assertion:

a. Please state whether ORA anticipates that such gas would be purchased pursuant to a long-term contract or spot market basis.

Response to 6a:

ORA objects to this question as outside the scope of Phase I of this proceeding, and of ORA's testimony. The evaluation of long-term contracts and spot market purchases are within the scope of Phase II of this proceeding**, including questions 24, 25, 27, 28**. ORA is considering both long-term contract and spot market basis and intends at this time to consider long-term and spot market purchases as part of the second phase of this proceeding. **ORA reserves the right to make future objections if this question is asked as part of Phase II. As part of Phase II of this proceeding, ORA would recommend that SoCalGas/SDG&E's Gas Acquisitions Group would propose a package that addresses all elements of data request 6, and that it recommends is in the best interests of core ratepayers.**

b. Please state whether the source of the gas is assumed to be the El Paso Natural Gas (EPNG) South Mainline system near Ehrenberg, Arizona or the Energia Costa Azul (ECA) liquefied natural gas (LNG) storage facility?

Response to 6b:

ORA objects to this question as outside the scope of testimony. The evaluation of long-term contracts and spot market purchases are within the scope of Phase II of this proceeding**, including questions 24 and 25**. ORA is considering both long-term contract and spot market basis and intends at this time to consider long-term and spot market purchases as part of the second phase of this proceeding. **ORA reserves the right to make future objections if this question is asked as part of Phase II. As part of Phase II of this proceeding, ORA would recommend that SoCalGas/SDG&E's Gas Acquisitions Group would propose a package that addresses all elements of data request 6, and that it recommends is in the best interests of core ratepayers.**

c. Please state all material terms of the hypothesized contract(s) to purchase gas for delivery at the Otay Mesa receipt point, including volume of gas purchased, price of gas, price of transportation, any other fees and costs, duration of the contract, any change in pricing during the duration of the contract.

Response to 6c:

ORA objects to this question on the grounds that it calls for speculation as to hypothesized contracts, assumes facts not in evidence about contracts to purchase gas, and that the term “material terms of the hypothesized contract(s)” is vague. ORA also objects on the grounds that questions regarding gas purchased, price of gas, price of transportation, any other fees and costs, duration of the contract, and any change in pricing during the duration of the contract is outside the scope of **Phase I** testimony. **The evaluation of these matters are within the scope of Phase II of this proceeding, including questions 24 and 25.** ORA will consider addressing some or all of these factors in Phase II. **ORA reserves the right to make future objections if this question is asked as part of Phase II. As part of Phase II of this proceeding, ORA would recommend that SoCalGas/SDG&E’s Gas Acquisitions Group would propose a package that addresses all elements of data request 6, and that it recommends is in the best interests of core ratepayers.**

d. If the source of gas is assumed to be the EPNG South Mainline system near Ehrenberg, Arizona, please state whether ORA confirmed with the owners of the North Baja Pipeline, Gasoducto Rosarito pipeline and the Transportadora de Gas Natural de Baja California (TGN) pipeline that transport capacity is available on their pipelines during the duration of each purchase contract. Please provide all documents reflecting ORA communications with such owners.

Response to 6d:

ORA objects to this question on the grounds that the availability of pipeline transport capacity during the duration of each purchase contract on the North Baja Pipeline, Gasoducto Rosarito pipeline and the Transportadora de Gas Natural de Baja California (TGN) pipeline is not part of the scope of this Phase of the proceeding. ORA will consider availability of pipeline transport capacity associated with these pipelines during Phase II of this proceeding. **The evaluation of these matters are within the scope of Phase II of this proceeding, including questions 24 and 25. ORA reserves the right to make future objections if this question is asked as part of Phase II. As part of Phase II of this proceeding, ORA would recommend that SoCalGas/SDG&E’s Gas Acquisitions Group would propose a package that addresses all elements of data request 6, and that it recommends is in the best interests of core ratepayers.**

e. If the source of gas is assumed to be the EPNG South Mainline system near Ehrenberg, Arizona, please state all material terms of the hypothesized contract(s) to transport gas for delivery at the Otay Mesa receipt point, including capacity rights purchased, the nature of such rights (e.g., firm or interruptible), the price of transportation, any other fees and

<u>costs, duration of the contract, and any change in pricing during the duration of the contract.</u>

Response to 6e:

ORA objects to this question on the grounds that it calls for speculation as to hypothesized contracts, assumes facts not in evidence about contracts to purchase gas, and that the term "material terms of the hypothesized contract(s)" is vague. ORA also objects on the grounds that questions regarding delivery at Otay Mesa receipt point involving gas purchased, price of gas, price of transportation, any other fees and costs, duration of the contract, and any change in pricing during the duration of the contract is outside the scope of testimony. ORA will consider addressing some or all of these factors in Phase II. **<u>The evaluation of these matters are within the scope of Phase II of this proceeding, including questions 24 and 25. ORA reserves the right to make future objections if this question is asked as part of Phase II. As part of Phase II of this proceeding, ORA would recommend that SoCalGas/SDG&E's Gas Acquisitions Group would propose a package that addresses all elements of data request 6, and that it recommends is in the best interests of core ratepayers.</u>**

f. <u>If the source of gas is assumed to be the ECA LNG storage facility, please state whether ORA confirmed with the owners of the storage rights that one or more of them are willing to sell re-gasified natural gas for delivery at the Otay Mesa receipt point. Please provide all documents reflecting ORA communications with such owners.</u>

Response 6f:

ORA objects to this question on the grounds that storage rights at ECA LNG storage facility and the question of whether owners of those storage rights are willing to sell re-gasified natural gas for delivery at the Otay Mesa receipt point is outside the scope of Phase I of this proceeding. ORA will consider these issues during Phase II of this proceeding. **<u>The evaluation of these matters are within the scope of Phase II of this proceeding, including questions 24 and 25. ORA reserves the right to make future objections if this question is asked as part of Phase II. As part of Phase II of this proceeding, ORA would recommend that SoCalGas/SDG&E's Gas Acquisitions Group would propose a package that addresses all elements of data request 6, and that it recommends is in the best interests of core ratepayers.</u>**

g. <u>If ORA anticipates that such gas would be purchased on a spot market basis, please state the anticipated price for such gas over the next 50 years.</u>

Response 6g:

ORA objects to this question as outside the scope of Phase I of the proceeding and of ORA testimony. The discussion of spot market purchase of gas is within the scope of Phase II of this proceeding. ORA is considering spot market basis and intends at this time to consider spot market purchases as part of the second phase of this proceeding. **The evaluation of these matters are within the scope of Phase II of this proceeding, including questions 24 and 25. ORA reserves the right to make future objections if this question is asked as part of Phase II. As part of Phase II of this proceeding, ORA would recommend that SoCalGas/SDG&E's Gas Acquisitions Group would propose a package that addresses all elements of data request 6, and that it recommends is in the best interests of core ratepayers.**

h. If ORA anticipates that such gas would be purchased on a spot market basis, please state why ORA believes that gas would be available for purchase when needed to serve SDG&E's customers.

Response 6h:

ORA objects to this question as outside the scope of Phase I of the proceeding and of ORA testimony. The discussion of spot market purchase of gas is within the scope of Phase II of this proceeding. ORA is considering spot market basis and intends at this time to consider spot market purchases as part of the second phase of this proceeding. **The evaluation of these matters are within the scope of Phase II of this proceeding, including questions 24 and 25. ORA reserves the right to make future objections if this question is asked as part of Phase II. As part of Phase II of this proceeding, ORA would recommend that SoCalGas/SDG&E's Gas Acquisitions Group would propose a package that addresses all elements of data request 6, and that it recommends is in the best interests of core ratepayers.**

END OF RESPONSE

Attachment C-6

ORA Response to Utilities' DR-05, Q8

ORA

Office of Ratepayer Advocates
California Public Utilities Commission

ELIZABETH ECHOLS
Director

505 Van Ness Avenue
San Francisco, California 94102
Tel: 415-703-2381
Fax: (415) 703-2057

http://ora.ca.gov

ORA Response to SDG&E/SoCalGas Data Request SCG/SDG&E-ORA-DR-05
Southern California Gas Company / San Diego Gas & Electric
CPCN for the Pipeline Safety and Reliability Project (L3602 / L1600)
Proceeding, A.15-09-013

Origination Date: April 26, 2017

Due Date: May 10, 2017

Responses Date: May 9, 2017

Revised Date: N/A

To: Shirley Amrany
Regulatory Case Manager
[redacted]
Telephone: [redacted]
E-mail: [redacted]

Yvonne Mejia
Email: [redacted]

Allen Trial, Counsel
Email: [redacted]

Richard Raushenbush, Counsel
Email: [redacted]

From: Oge Enyinwa, Project Coordinator
Office of Ratepayer Advocates
[redacted]
Email: [redacted]

Response by: Nathaniel Skinner

Phone: [redacted]
Email: [redacted]

Mina Botros
[redacted]
Email: [redacted]

ORA Counsel Darryl Gruen
Email: [redacted]

Data Request No: SCG/SDG&E-ORA-DR-05
Exhibit Reference**:** ORA-02 – Ch. 2 Direct Testimony – N Skinner and M Botros
Subject: Data Request Response

The following is ORA's response to SCG/SDG&E's data request. If you have any questions, please contact the responder at the phone number and/or email address shown above.

> conservative in comparison with in-service incidents. Thresholds for the transition from leak to rupture also were evaluated for immediate as well as delayed mechanical damage incidents with reference to fullscale test data, incident data, and mechanics and fracture analysis. Full-scale test data indicated this threshold was in excess of 30 percent of SMYS, the lowest threshold identified for rupture due to corrosion, whereas the steels represented in reportable incidents possess toughness [sic] indicated a threshold on order of 25 percent of SMYS."

ORA's recommended MAOP of 20% SMYS falls below the lowest leak to rupture SMYS threshold level of 25% in this excerpt of the report quoted by Mr. Sera.

DATA REQUEST NO. 8

All other things being equal, please state and explain whether ORA considers it safer to operate Line 1600 with a MAOP of 325 psig compared to a MAOP of 320 psig. Please state all facts that support your response, produce all documents that support your response, and identify the person responsible for this response.

ORA objects to this question as assuming facts not in evidence. All other things are not equal. SoCalGas/SDG&E have a proposed project that does not pressure test Line 1600 and ORA believes the proposed project leaves that line as a transmission line as discussed in ORA testimony Exhibit ORA-02; whereas ORA's testimony recommends a pressure test on Line 1600 to validate a reduced MAOP of 325 psig in a fashion that comports with state and federal requirements as identified in response to question 7c.

Notwithstanding this objection, ORA answers as follows:

SoCalGas/SDG&E stated and identified repeatedly that Line 1600 was safe at previous MAOPs far in excess of 325 psig. (See for example, SoCalGas/SDG&E response to ORA data request 12, questions 5 and 13 quoted below). SoCalGas/SDG&E also stated that the TIMP assessments did not find a need for the pipeline to be derated, replaced, or tested after both direct assessment and in-line inspections. Based on the "Leak versus Rupture Considerations for Steel Low-Stress Pipelines" by Leis et al, cited in the Testimony of Sera, the benefits of reducing pipeline MAOP to 25% SMYS or lower indicates little to no difference in safety between operating Line 1600 at 325 versus 320 psig, which is a difference of 0.0031% of the overall pipeline pressure based on design, after the weakest 0.5 miles have been replaced. Given that both ORA and SoCalGas/SDG&E propose operating Line 1600 with a maximum operating pressure of 300 psig (Ex. ORA-02, p. 1, including FN 2), there is no difference in expected conditions or safety from an operational standpoint, except that ORA's recommendation to maintain the pipeline under more stringent TIMP requirements including requirements for direct inspection, testing, or in-line inspection, should identify any potential flaws that the less stringent DIMP requirements could miss.

Leis et al, p. 32:

> Thresholds for the transition from leak to rupture also were evaluated for immediate as well as delayed mechanical damage incidents with reference to full-scale test data, incident data, and mechanics and fracture analysis. Full-scale test data indicated this threshold was in excess of 30 percent of SMYS, the lowest threshold identified for rupture due to corrosion, whereas the steels represented in reportable incidents possess toughness indicated a threshold on order of 25 percent of SMYS. Analysis indicated that rupture due to delayed mechanical damage required the coincidence of many unlikely circumstances. Probabilistic calculations best indicate the coupled likelihood of such events, and are currently being done. In the absence of results from this continuing work, the threshold for rupture due to mechanical damage must be taken as the lesser of the above-cited results, that is 25 percent of SMYS.

SOCALGAS/SDG&E RESPONSE TO ORA DR 12, QUESTION 5:

"Did SoCalGas/SDG&E's baseline Transmission Integrity Management Plan assessment indicate that Line 1600 should be derated? Replaced? Tested? Please provide the portion of the TIMP that shows the indication for Line 1600.

RESPONSE 5:

The baseline assessment utilizing Direct Assessment did not indicate that Line 1600 should be permanently derated, replaced, or tested. The baseline Direct Assessment results are included in SDG&E's and SoCalGas' response to ORA Data Request 6, Question 15. Line 1600 was subsequently assessed using in-line inspection (see SDG&E's and SoCalGas' ORA Data Request 7, Question 10). The ILI inspection also did not result in having the pipeline permanently derated, replaced or tested."

SOCALGAS/SDG&E RESPONSE TO ORA DR 12, QUESTION 13:

"Was Line 1600 safe to operate at the original Maximum Allowable Operating Pressure of 800 psig?

RESPONSE 13:

Yes."

DATA REQUEST NO. 9

Please state ORA's estimate of the remaining useful life of SDG&E's Line 3010. Please state all facts that support your response, produce all documents that support your response, and identify the person responsible for this response.

ORA objects to this question as outside the scope of its testimony. ORA's testimony did not estimate the remaining useful life of SDG&E's Line 3010.

Attachment C-7

ORA Response to Utilities' DR-07, Q5, Q9, Q10, Q12, Q17

ORA

Office of Ratepayer Advocates
California Public Utilities Commission

505 Van Ness Avenue
San Francisco, California 94102
Tel: 415-703-2381
Fax: (415) 703-2057

http://ora.ca.gov

ORA Response to SDG&E/SoCalGas Data Request SCG/SDG&E-ORA-DR-07
Southern California Gas Company / San Diego Gas & Electric
CPCN for the Pipeline Safety and Reliability Project (L3602 / L1600)
Proceeding, A.15-09-013

Origination Date: May 1, 2017

Due Date: May 15, 2017

Responses Date: May 17, 2017

Revised Date: N/A

To: Shirley Amrany
Regulatory Case Manager
[redacted]
Telephone: [redacted]
E-mail: [redacted]

Yvonne Mejia
Email: [redacted]

Allen Trial, Counsel
Email: [redacted]

Richard Raushenbush, Counsel
Email: [redacted]

From: Oge Enyinwa, Project Coordinator
[redacted]
Email: [redacted]

Response by:	Pearlie Sabino Phone: [redacted] Email**:** [redacted]
	Mina Botros [redacted] Email: [redacted]
ORA Counsel	Darryl Gruen Email: [redacted]

Data Request No:	SCG/SDG&E-ORA-DR-07
Exhibit Reference**:**	
	ORA-01 – Ch. 1 Direct Testimony – P Sabino ORA-03 – Ch. 3 Direct Testimony – M Botros
Subject:	Data Request Response

The following is ORA's response to SCG/SDG&E's data request. If you have any questions, please contact the responder at the phone number and/or email address shown above.

DATA REQUEST NO. 5

ORA-1 at page 13, lines 13-17, acknowledges that the Energia Costa Azul (ECA) liquefied natural gas (LNG) facility's storage capacity is held by other entities, Shell, Gazprom and IEnova LNG, and that the storage capacity held by Shell and Gazprom remain unused since the start of operations. ORA then queries "Is there any interest among ECA capacity holders to make productive use of the idle ECA storage capacity?" With this testimony in mind, please answer the following questions:

a. Has ORA communicated with Shell regarding their ECA LNG storage capacity? If so, please produce any communications and documents reflecting such communications.

b. Has ORA communicated with Gazprom regarding their ECA LNG storage capacity? If so, please produce any communications and documents reflecting such communications.

c. Please respond either yes or no to the following question, has ORA communicated with IEnova LNG regarding their ECA LNG storage capacity? As ORA is aware, IEnova LNG is Applicants' affiliate and as such, Applicants request that you **do not** produce any documents and communications related to ORA's interaction with them.

Response No.5a through 5c:

No.

DATA REQUEST NO. 9

With respect to Application 15-06-020, Application of Southern California Gas Company (U904G) and San Diego Gas & Electric Company (U902G) for Authority to Revise their Curtailment Procedure," discussed in ORA-1 at 42-44:

a. Was ORA a party to that proceeding?

b. Did ORA object to the Curtailment Procedures Settlement Agreement discussed in Commission Decision 16-07-008 (July 14, 2016) and attached thereto? If yes, provide a copy of any document reflecting such objection and provide the locations within the document where the objection is made.

c. Did ORA oppose the Joint Motion, dated April 28, 2016, of Southern California Gas Company, San Diego Gas & Electric Company (the "Applicant Utilities"), the California Independent System Operator, Southern California Edison Company, Southern California Generation Coalition, Indicated Shippers, and the California Manufacturers & Technology Association for approval of the Curtailment Procedures Settlement Agreement? If yes, provide a copy of any document reflecting such opposition and provide the locations within the document where the objection is made.

d. Admit that Decision 16-07-008, Ordering Paragraph 2 states: "Southern California Gas Company and San Diego Gas & Electric Company are directed to implement the terms of the Curtailment Procedures Settlement Agreement by filing a Tier 1 Advice Letter, consistent with the tariff sheet modifications in the Settlement Agreement set forth in Attachment 1."

e. Admit that the Attachment to the Settlement Agreement approved by Decision 16-07-008 eliminated the "Gas Transportation Service Levels" of "firm noncore service" and "interruptible noncore service," leaving simply "noncore service," in SDG&E Gas Rule 14, Paragraph E. If ORA's answer is anything other than an unqualified yes, please explain the factual basis for ORA's response, produce any documents supporting ORA's response, and identify the person responsible for drafting the response.

f. Admit that SDG&E filed Advice Letter 2522-G on October 25, 2016, seeking Commission approval of the tariff sheet modifications shown in Attachment 1 to the Settlement Agreement approved by Decision 16-07-008, and that the Commission approved such tariff sheet modifications by letter dated November 16, 2016. If ORA's answer is anything other than an unqualified yes, please explain the factual basis for ORA's response, produce any documents supporting ORA's response, and identify the person responsible for drafting the response.

g. Admit that SDG&E's Gas Rule 14, Paragraph E, offers "Noncore Service," but not offer firm or interruptible noncore service. If ORA's answer is anything other than an unqualified yes, please explain the factual basis for ORA's response, produce any documents supporting ORA's response, and identify the person responsible for drafting the response.

Response No.9a:

Yes.

Response No.9b:

ORA was neither a settling party nor an objector to the SoCalGas/SDG&E Curtailment Procedures Settlement Agreement in A.15-06-020 which was adopted in D.16-07-008.

Response No.9c:

ORA took no position with respect to the Joint Motion, dated April 28, 2016, of Southern California Gas Company, San Diego Gas & Electric Company (the "Applicant Utilities"), the California Independent System Operator, Southern California Edison Company, Southern California Generation Coalition, Indicated Shippers, and the California Manufacturers & Technology Association for approval of the Curtailment Procedures Settlement Agreement.

Response No.9d:

ORA objects to the posture of this question asking for an admission. ORA is not providing an admission in its response to this question. ORA hereby puts Applicants on notice that any suggestion on Applicants' part in rebuttal testimony or elsewhere that states or in any way suggests that ORA admits that "Decision 16-07-008, Ordering Paragraph 2 states: 'Southern California Gas Company and San Diego Gas & Electric Company are directed to implement the terms of the Curtailment Procedures Settlement Agreement by filing a Tier 1 Advice Letter, consistent with the tariff sheet modifications in the Settlement Agreement set forth in Attachment 1.", will be deemed by ORA as a mischaracterization of ORA's position in testimony, and a mischaracterization of ORA's response to discovery. ORA further reserves the right to clarify any testimony from Applicants that mischaracterizes ORA as providing an admission regarding this response, including quotation and citation of this data response.

ORA also objects that asking for agreement that D.16-07-008 Ordering Paragraph 2 calls for an ORA witness to make a legal conclusion. Moreover, SoCalGas/SDG&E does not require ORA to make such an acknowledgement on the record in order to cite D.16-07-008, Ordering Paragraph 2 in briefs in this proceeding. Notwithstanding this objection, ORA does not dispute that Decision 16-07-008, Ordering Paragraph 2 states: "Southern California Gas Company and San Diego Gas & Electric Company are directed to implement the terms of the Curtailment Procedures

Settlement Agreement by filing a Tier 1 Advice Letter, consistent with the tariff sheet modifications in the Settlement Agreement set forth in Attachment 1."

Response No.9e:

ORA objects to the posture of this question asking for an admission. ORA is not providing an admission in its response to this question. ORA hereby puts Applicants on notice that any suggestion on Applicants' part in rebuttal testimony or elsewhere that states or in any way suggests that ORA admits that, "the Attachment to the Settlement Agreement approved by Decision 16-07-008 eliminated the "Gas Transportation Service Levels" of "firm noncore service" and "interruptible noncore service," leaving simply "noncore service," in SDG&E Gas Rule 14, Paragraph E." will be deemed by ORA as a mischaracterization of ORA's position in testimony, and a mischaracterization of ORA's response to discovery. ORA further reserves the right to clarify any testimony from Applicants that mischaracterizes ORA as providing an admission regarding this response, including quotation and citation of this data response.

Notwithstanding this objection, ORA does not dispute that the Attachment to the Settlement Agreement approved by Decision 16-07-008 eliminated the "Gas Transportation Service Levels" of "firm noncore service" and "interruptible noncore service," leaving simply "noncore service," in SDG&E Gas Rule 14, Paragraph E.

Response No.9f:

ORA objects to the posture of this question asking for an admission. ORA is not providing an admission in its response to this question. ORA hereby puts Applicants on notice that any suggestion on Applicants' part in rebuttal testimony or elsewhere that states or in any way suggests that ORA admits that, "SDG&E filed Advice Letter 2522-G on October 25, 2016, seeking Commission approval of the tariff sheet modifications shown in Attachment 1 to the Settlement Agreement approved by Decision 16-07-008, and that the Commission approved such tariff sheet modifications by letter dated November 16, 2016." will be deemed by ORA as a mischaracterization of ORA's position in testimony, and a mischaracterization of ORA's response to discovery. ORA further reserves the right to clarify any testimony from Applicants that mischaracterizes ORA as providing an admission regarding this response, including quotation and citation of this data response.

Notwithstanding this objection, ORA does not dispute that SDG&E filed Advice Letter 2522-G on October 25, 2016 and that the Commission approved such tariff sheet modifications by letter dated November 16, 2016

Response No.9g:

ORA objects to the posture of this question asking for an admission. ORA is not providing an admission in its response to this question. ORA hereby puts Applicants on notice that any suggestion on Applicants' part in rebuttal testimony or elsewhere that states or in any way suggests that ORA admits that, "SDG&E's Gas Rule 14, Paragraph E, offers "Noncore Service," but not offer firm or interruptible noncore service." will be deemed by ORA as a mischaracterization of ORA's position in testimony, and a mischaracterization of ORA's response to discovery. ORA further reserves the right to clarify any testimony from Applicants that mischaracterizes ORA as providing an admission regarding this response, including quotation and citation of this data response.

Notwithstanding this objection, ORA does not dispute that SDG&E's Gas Rule 14, Paragraph E, offers "Noncore Service," but not offer firm or interruptible noncore service.

DATA REQUEST NO. 10

In ORA-1 at 2, ORA states: "The Applicant is required to have open seasons as these are standard practice." With respect to this statement:

a. Please identify any law, regulation or Commission decision that ORA contends "requires" Applicants to "have open seasons" with respect to a project to enhance safety and increase reliability, as opposed to allocate or expand capacity.

b. Please state the terms of the "open season" that ORA contends should be held with respect to the Proposed Project including whom it should be directed to and what such entities would be bidding on.

c. Please identify all instances where new pipeline facilities were added to the Applicants' natural gas transmission system and whether open seasons were held prior to those additions. Please state all facts and produce any documents supporting your response and identify the person responsible for drafting the response.

Response No. 10a:

In the above quoted statement in Exhibit ORA-01 at page 2, ORA cites reference in footnote 8 to discussion in section III.B.1 through B.4 of the exhibit. Those sections cite to the two previous Commission decisions namely, D.02-11-073 and D.06-09-039 which adopt system planning criteria and reliability standards for both SoCalGas/SDG&E and required these utilities to use open seasons to determine need, timing, and location of capacity additions. The requirement to use open seasons are pursuant to the adopted system planning and reliability standards, and therefore, enhanced safety and increased reliability are assumed to be inherent in these standards. As D.14-06-007 states "As required by Pub. Util. Code § 451, safe operation of a natural gas system is the operator's long-standing and continuing responsibility, not a one-time event. Moreover, an unreliable or ruptured pipeline delivers no gas to any class of customer."

Response No. 10b:

ORA objects to this question in the grounds that the specific terms of the open season are outside the scope of ORA's Phase 1 Testimony. In Phase 1, ORA recommends the gathering of additional information through the conduct of RFOs to query the market and determine the level of interest which could inform the terms of the open season. ORA reserves the right to take a position on this issue that is based on discovery and the evidence produced by other parties in A.15-09-013.

Response No. 10c:

To ORA's knowledge, the Applicants have held various open seasons since the above decisions in D.02-11-073 and D.06-09-039 with respect to their natural gas transmission system as discussed on pages 42-43 of Exhibit ORA-01. Footnote 158 of the exhibit referenced discovery response received by ORA in ORA-08 Q.9 describe open seasons by SDG&E during Jan.1, 2014 through April 2016 period. However, whether those open seasons resulted in all instances in the addition of new pipeline facilities to the Applicants' natural gas transmission system is outside the scope of ORA's Phase 1 Testimony.

DATA REQUEST NO. 12

In ORA-1 at 2, ORA states that it recommends: "The Commission authorizes the conduct of an Request for Offer (RFO) regarding the Otay Mesa Alternatives …." With respect to such testimony:

a. State whether such RFO should seek delivery of gas to SDG&E's Otay Mesa receipt point. If so, state all material terms of such RFO, including but not limited to the volume of gas sought, how often such gas would be delivered, and the duration of the proposed Contract

b. State whether such RFO should seek firm capacity on each of the North Baja Pipeline, Gasoducto Rosarito and TGN. If so, state all material terms of such RFO, including but not limited to the volume of firm capacity sought on each pipeline, and the duration of the proposed contract.

c. State whether such RFO should seek storage capacity at the ECA storage facility. If so, state all material terms of such RFO, including but not limited to the volume of storage capacity sought, rights to re-gasification and delivery to SDG&E's Otay Mesa receipt point, and the duration of the proposed contract.

Response No.12a:

Because of the need for additional information related to the Otay Mesa Alternatives discussed in Exhibit ORA-01, ORA has not developed the specific material terms of such RFO which will have the objective of seeking reliable delivery of gas to SDG&E's Otay Mesa receipt point at this time.

Response No.12b:

Please refer to the above response 12a.

Response No.12c:

Please refer to the above response 12a.

DATA REQUEST NO. 17

Does ORA consider it prudent to be able to serve all SDG&E gas customers (including core, non-core and electric generation) in the event of a Line 3010 outage, less than all SDG&E gas customers, or none of SDG&E gas customers? If your response is anything other than “all SDG&E gas customers,” please indicated which customers ORA recommends not be served. Please explain the basis for your response, stating all supporting facts, producing all supporting documents, and identifying the person(s) responsible for preparing the response?

Response No.17:

ORA maintains that SDG&E should strive to serve all its customers in the event of a Line 3010 outage, pursuant to its obligation to serve mandate. However, Exhibit ORA-03 concludes and provides data supporting its conclusion that “Recent historic data show that the occurance of unplanned outages on Line 3010 and at Moreno Compressor Station has been rare.” Pages 2 through 6 of that exhibit provide the data in support of that statement. ORA reserves the right to take a position on this issue based upon responses to discovery or testimony from other parties.

Attachment D

PHMSA Documents

Attachment D-1

PHMSA PI-91-0103 (May 30, 1991)

PI-91-0103

Mr. Dan H. Weaklend
Chief, Pipeline Safety
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

Dear Mr. Weaklend:

I am responding to your letter of March 4, 1991, concerning the classification of pipelines under 49 CFR 192 as transmission lines or mains. You asked about four pipelines shown as #1, #2, #5, and #6 on enclosures. You also asked if pressure reduction points shown as #3 and #4 on the enclosures are pressure limiting or regulating stations.

The Part 192 regulations contain the following definitions that re relevant to this discussion:

<u>Distribution line</u> means a pipeline other than a gathering or transmission line.

<u>Main</u> means a distribution line that serves as a common source of supply for more than one service line.

<u>Transmission line</u> means a pipeline, other than a gathering line, that:

(a) Transports gas from a gathering line or storage facility to a distribution center or storage facility;

(b) Operates at a hoop stress of 20 percent or more SMYS; or

(c) Transports gas within a storage field.

Comprehension of the term, "distribution center," is essential to use of the transmission line definition. As we apply the term, it is the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale.

Line #1, which operates at less than 20 percent of SMYS, begins at a pressure limiting and metering station on an interstate natural gas transmission pipeline. From there the line extends to a series of pressure reduction points, beyond which the gas is distributed to consumers. Because there does not appear to be any transfer of gas to customers for resale beyond the pressure limiting and metering station, this station marks a distribution center under the above description. Line #1 is, therefore, a distribution line, or main, as it is a common source of supply for more than one service line.

Line #2 runs between the last pressure reduction point on Line #1 and another pressure reduction point. It is an extension of Line #1 and is, thus, a main.

Lines #6 and #6 are like Line #1, except they extend to fewer pressure reduction points than Line #1, and, on Line #6, two of these points are on connecting laterals. Since these dissimilarities to Line #1 are not relevant for the purpose of classification, Lines #5 and #6 are mains.

As for pressure reduction points #3 and #4, Part 192 does not define pressure limiting or regulating stations, though we have a rulemaking project to create a Part 192 definition for these terms. Terms used in Part 192 that are not defined in Part 192 have the ordinary meaning in the industry. We rely on the definitions in the B31.8 Code as indicative of the ordinary meaning of such terms in the industry. Based on the B31.8 definitions of pressure limiting or regulating station and of service regulator, point #3 is a pressure limiting or regulating station and point #4 is a service regulator.

Please call me if you need any further help in this matter.

Sincerely,

/signed/

Cesar DeLeon
Director for Pipeline Safety
Regulatory Programs

Attachment D-2

PHMSA PI-09-0019 (March 22, 2010)

U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, D.C. 20590

MAR 2 2 2010

Mr. Joe M. Johnson
Acting Bureau Chief
New Mexico Public Regulation Commission
Pipeline Safety Bureau
1120 Paseo de Peralta
Santa Fe, New Mexico 87504

Dear Mr. Johnson:

In a letter to the Pipeline and Hazardous Materials Safety Administration (PHMSA) dated September 15, 2009, you requested an opinion/interpretation on whether the following pipelines operated by New Mexico Gas Company (NMGC) should be regulated as transmission pipelines or distribution pipelines (as described by New Mexico Public Regulation Commission):

1. Animas Power Plant 6" diameter - an intrastate natural gas pipeline that transports natural gas from a transmission line to a large volume customer (Animas Power Plant).

2. Farmington (Bluffview) Power Plant 8" diameter - an intrastate natural gas pipeline that transports natural gas directly from a transmission line to large volume customers (Animas and Bluffview power plants).

3. Tucumcari Mainline - an intrastate natural gas pipeline that transports natural gas directly from a transmission to distribution centers (Tucumcari Townplant, Northeast Regulator Station, and Baker Kelso Regulator Station). This pipeline is a continuation of the Clovis Transmission Line that transports natural gas from El Paso Natural Gas Company's intrastate pipeline system to New Mexico Gas Company's Northeast Area distribution centers, and is not downstream of a distribution center.

   NMGC has designated a valve at the Clovis Border Regulator Station as the end point of the Clovis Transmission Line and the beginning of the Tucumcari and Cannon mainlines. The Clovis Transmission line and the Tucumcari and Cannon mainlines all operate at 300 psig. The Tucumcari Mainline runs approximately 62 miles from Mile Post 0 at the Clovis Border Regulator Station to the Tucumcari Townplant distribution center.

4. Cannon Mainline - an intrastate natural gas pipeline that transports natural gas directly from a transmission to distribution centers (Northwest Regulator Station, Mixon lane Regulator Station, Hayfield Farmers Regulator Station, 6084 Regulator Station, Port Air Dairyman Regulator Station, Port Air Farmers Regulator Station, and Clovis Expansion Regulator Station). This pipeline is a continuation of the Clovis Transmission line that

transports natural gas from EI Paso Natural Gas Company's Intrastate pipeline system to New Mexico Gas Company's Northeast Area distribution centers, and is not downstream of a distribution center.

5. Northeast Distribution Mainline - an intrastate natural gas pipeline. The pipeline is a loop line that can be used to: (a) transports natural gas from EI Paso Natural Gas Company's interstate pipeline via NMGC's Clovis Transmission line to the Tucumcari Townplant distribution center without going to the Clovis Border Regulator Station, or (b) transport natural gas to the Clovis Townplant distribution center via the Tucumcari Mainline.

6. Portales Mainline - an intrastate natural gas pipeline that transports natural gas from the Clovis Transmission line, and Transwestern's interstate transmission line to distribution centers (Portales Townplant, Grinder Regulator Station, Baxter Regulator Station, Midway Regulator Station, and Cameo Regulator Station). Pressure on the pipeline is regulated at 200 psig just downstream of the Transwestern interconnect at the Clovis Transmission line. There are no service lines on the Portales Mainline and the pipeline runs approximately 20 miles to the Portales Townplant distribution center.

Based on the provided information, we agree with the Commission's determination that all of the specified lines meet the definition of a transmission line. PHMSA's responses concerning each of the specified lines are as follows:

1. Regarding the Animas Power Plant 6" line, we believe this line is a transmission line because under the first definition of a transmission line this line transports gas from a transmission line to a large volume customer that is not downstream from a distribution center.

2. Regarding the Farmington (Bluffview) Power plant 8" line, we believe this line is a transmission line because under the first definition of a transmission line this line transports gas from a transmission line to a large volume customer that is not downstream from a distribution center.

3. Regarding the Tucumcari Mainline, we do not consider a decrease in pressure to below 20 percent SMYS at a transmission line to be a "distribution center" and lines downstream of that point to be distribution lines – this would violate the intent of the pipeline safety regulations. We consider a "distribution center" to be the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale. Therefore, in our opinion, this line is an extension of the Clovis transmission line.

4. Regarding the Cannon Mainline, we do not consider a decrease in pressure to below 20 percent SMYS at a transmission line to be a "distribution center" and lines downstream of that point to be distribution lines – this would violate the intent of the pipeline safety regulations. We consider a "distribution center" to be the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to

customers who purchase it for resale. Therefore, in our opinion, this line is an extension of the Clovis transmission line.

5. Regarding the Northeast Distribution Mainline, we do not consider a decrease in pressure to below 20 percent SMYS at a transmission line to be a "distribution center" and lines downstream of that point to be distribution lines – this would violate the intent of the pipeline safety regulations. We consider a "distribution center" to be the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale. Therefore, in our opinion, this line is an extension of the Clovis transmission line or the Tucumcari Mainline as described by PSB.

6. Regarding the Portales Main line, we do not consider a decrease in pressure to below 20 percent SMYS at a transmission line to be a "distribution center" and lines downstream of that point to be distribution lines – this would violate the intent of the pipeline safety regulations. We consider a "distribution center" to be the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale. Therefore, in our opinion, this line is an extension of the Clovis Transmission line and Transwestern transmission line.

For your information, on September 25, 2009, PHMSA received a letter from NMGC concerning your interpretation request. PHMSA is providing NMGC with a copy of this letter and a copy of PHMSA's response to NMGC is enclosed. I hope that this information is helpful to you. If I can be of further assistance, please contact me at (202) 366-4046.

Sincerely,

John A. Gale
Director, Office of Regulations

Enclosures

U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, D.C. 20590

MAR 2 2 2010

Mr. Thomas M. Domme
Vice President and General Counsel
New Mexico Gas Company
P.O. Box 97500
Albuquerque, NM 87199-7500

Dear Mr. Domme:

In a letter to the Pipeline and Hazardous Materials Safety Administration (PHMSA) dated September 25, 2009, you expressed your views concerning a September 15, 2009, request for interpretation submitted to PHMSA by the New Mexico Public Regulation Commission (Commission). You explained that New Mexico Gas Company (NMGC) was engaged in settlement talks with the Commission concerning a matter that potentially involved the issues for which the Commission sought interpretation from PHMSA.

To the extent you questioned the procedural validity of the Commission's request, we find it was properly submitted. PHMSA maintains open and continuous communications with our State regulatory partners at a variety of formal and informal levels. Note that requests for interpretation are explanatory in nature and are intended only to apply existing laws and requirements to a particular scenario presented by the requester. Interpretations do not create new requirements not already in the pipeline safety laws and regulations.

To the extent you questioned the factual details set forth by the Commission in its request, please be advised that PHMSA must assume the scenario presented by the requester is the one the requester is interested in for purposes of obtaining information on how the regulations would apply. PHMSA makes no attempt to investigate or otherwise verify the information provided by the requester (in some cases, the scenarios presented to PHMSA by a requester may even be hypothetical). In preparing our response to the Commission, however, we were aware of the information you provided in your September 25, 2009, letter, and as you know my staff had telephone conversations with NMGC as well as the Commission. For your information, a copy of PHMSA's response to the Commission is enclosed with this letter.

I hope that this information is helpful to you. If I can be of further assistance, please contact me at (202) 366-4046.

Sincerely,

John A. Gale
Director, Office of Regulations

Enclosure

Attachment D-3

PHMSA PI-78-0110 (November 30, 1978)

PI-78-0110

November 30, 1978

Mr. A. D. Simpson, III
East Tennessee Natural Gas Company
P.O. Box 2511
Houston, Texas 77001

Dear Mr. Simpson:

As a result of your September 6, 1978, letter supplying additional information about the Kingsport Lateral System, we have reconsidered our Interpretation of August 2, 1978, that the portion of the Kingsport Lateral System used to deliver gas to the General Shale Corporation is not a "transmission line."

Of particular importance is your point that the present definition of "transmission line" in 49 CFR 192.3 was not preceded by a proposed definition of the term in the notices of proposed rulemaking upon which Part 192 is based. Since the term "transmission line" was used in those notices and the notices were, in general, based on the U.S.A.S. B31.8 Code (1968 ed.), we agree that the notices must have been drafted with the B31.8 definition of "transmission line" in mind. Under these circumstances, it would be improper to conclude as we did in the August 2, 1978, Interpretation that the adopted definition of "transmission line" in Part 192 was intended to alter the meaning intended by the B31.8 Code.

Since the term "transmission line" in Part 192 is intended to have the same meaning as that in the B31.8 Code, it follows that the term "distribution center," which marks the end of a "transmission line" in the adopted definition, must be interpreted to include a "large volume customer," a term which marked the end of a "transmission line" under the B31.8 Code.

To apply this interpretation, we must determine what B31.8 meant by "large volume customer." There is no question that as we previously stated, a "distribution center" occurs at a "point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption." Basically, this includes points where title to gas is transferred from a transmission company to a distribution company. Since in the B31.8 Code, the terms "distribution center" and "large volume customer" were both used to define the end of a "transmission line," it is logical to conclude that except for the factor of resale, a "large volume customer" meant a customer with attributes similar to those of a distribution company. Foremost among these attributes are the receipt of similar volumes of gas and the operation of piping facilities common to a distribution company. Thus, a customer fitting this description would also represent a "distribution center" under Part 192.

To properly answer your original inquiry, we have looked at whether the General Shale Corporation qualifies as a "large volume customer" within the meaning of the B31.8 Code. Based on the information you have submitted, we find that General Shale (1) receives gas in a quantity almost as large as that delivered to the neighboring distribution company, Volunteer Natural Gas Company; and (2) operates piping similar to that operated by a distribution company. Since these factors characterize a "large volume customer" within the meaning of "distribution center" under the adopted "transmission line" definition, the portion of the Kingsport Lateral System serving General Shale, or the General Shale lateral, is a "transmission line" under Part 192. Further, based on the information provided in your May 17, 1978, letter concerning class locations, it appears that at least 50 percent of the length of the General Shale lateral is in a Class 1 location, and therefore, the lateral is exempt from orodization under section 192.625(b((3).

To ensure that our interpretation of "transmission line." particularly the "distribution center" aspect regarding "large volume customers" is applied uniformly, we intend to publish it in the Federal Register. At the same time, we will invite public comments on the Impact of this interpretation on the regulated industry and on public safety, and also on our judgment as to what constitutes a "large volume customers." If the comments warrant it, we may change our interpretation or propose to change the definition of "transmission line."

Sincerely,

Cesar DeLeon
Associate Director for
Pipeline Safety Regulation
Materials Transportation Bureau

August 2, 1978

Mr. A. D. Simpson, III
East Tennessee Natural
Gas Company
P. O. Box 2511
Houston, Texas 77001

Dear Mr. Simpson:

By letter of May 17, 1978, you requested our opinion on whether 49 CFR 192.625(b)(1) and (2) requires East Tennessee to odorize that portion of its Kingsport Lateral System that is used to deliver gas to the General Shale Corporation.

As shown on Exhibit A to your May 17 letter, the Kingsport Lateral System consists of an arrangement of interlocking pipelines from East Tennessee's 3300 line. That portion of the System serving General Shale consists of the Kingsport Lateral, about 2,642 feet of the Mead Corporation Lateral, and the General Shale Lateral.

To answer you correctly, we asked for an explanation of East Tennessee's basis for classifying that portion of the System serving General Shale as a "transmission line" under Part 192. This information was provided by your letter of June 9, 1978.

You have made at least three separate arguments: First, you point out that under the industry code in effect before the adoption of 49 CFR Part 192 (the ANSI B31.8 Code), a "transmission line" was defined as " 'pipe installed for the purpose of transmitting gas from a source or sources of supply to one or more distribution centers or to one or more large volume customers...'" Because of the volume being delivered to General Shale (4196 Mcf/d), presumably we are to conclude that the pipeline involved is a transmission line under the ANSI definition. Regardless of such a conclusion, however, the term "transmission line" is defined in Part 192 (§192.3), and it is that definition that we must look to first in determining which gas pipelines are subject to Part 192 standards that apply to transmission lines. Only if the "transmission line" definition is considered ambiguous in any respect would we look for clarifying information in background documents such as the B31.8 Code.

Your next argument relates to the statutory definition of the term "interstate transmission facilities." You state that all East Tennessee's facilities fall within that statutory definition and, therefore, are by implication "transmission pipelines." Notwithstanding this implication, the term "transmission line" in Part 192 is not defined in terms which relate to an "interstate transmission facility." Therefore, it cannot be correctly concluded that if a pipeline fits the statutory definition of "interstate transmission facility," it is consequently a "transmission line" under Part 192. Further, while we disagree with your interpretation of the 1976 amendment to the statutory definition of "interstate transmission facility," we concur with your view that there is no relation between that amendment and the classification of pipelines as "transmission lines" under Part 192.

Your last argument relates to the definition of the term "transmission line" in Section 192.3. Under Section 192.3, if a gas pipeline which is not a gathering line (1) either transports gas from a gathering line or storage facility to a distribution center or storage facility,(2) operates at 20 percent or more of SMYS, or (3) transports gas within a storage field, it is a "transmission line." Otherwise it is a "distribution line." Considering all the information presented (including the excerpted Technical Pipeline Safety Standards Committee transcript), it appears that by this definition, that portion of the Kingsport Lateral System used to deliver has to the General Shale Corporation would be a transmission line in its entirety only if the point of delivery qualifies as a "distribution center." Since this latter term is not defined, it must be interpreted in light of its ordinary meaning and usage in the industry.

You have argued that the point of delivery to General Shale is a "distribution center" because the downstream piping is "a distribution network which delivers gas to the various points of utilization in the General Shale plant." We are not persuaded, however, that the natural gas transmission industry commonly refers to a point of delivery to an industrial customer as a "distribution center." The word "distribution" itself has a plural connotation, and the ANSI definition of "transmission line" which you cited distinguishes "distribution centers" from "large volume customers."

We have not found a written definition of the term "distribution center" in ANSI B31.8 or in other relevant background material. Nevertheless, we believe that the term commonly refers to that point where gas enters piping used primarily to deliver gas to customers who purchases it for consumption as opposed to customers who purchase it for resale. In this sense, the connection of the Kingsport Lateral with the 3300 Line is a "distribution center," and the downstream piping comprises either mains or service lines which must be odorized under the requirements of Section 192.625(a).

We recognize that under this interpretation, the lines serving General Shale have a different classification than existed under ANSI B31.8 prior to the adoption of Part 192. However, we have no reason to believe that the Part 192 definition of "transmission line" - inasmuch as it deletes the reference to large volume customers contained in the ANSI definition - was not intended to alter prior classifications. Indeed, just the opposite seems true, as indicated by the preamble to Part 192 where it is stated with respect to Section 192.3, "We have defined those terms which are being used in a different sense than the commonly understood meaning.

Sincerely,
Cesar De Leon
Associate Director for
Pipeline Safety Regulation
Materials Transportation Bureau

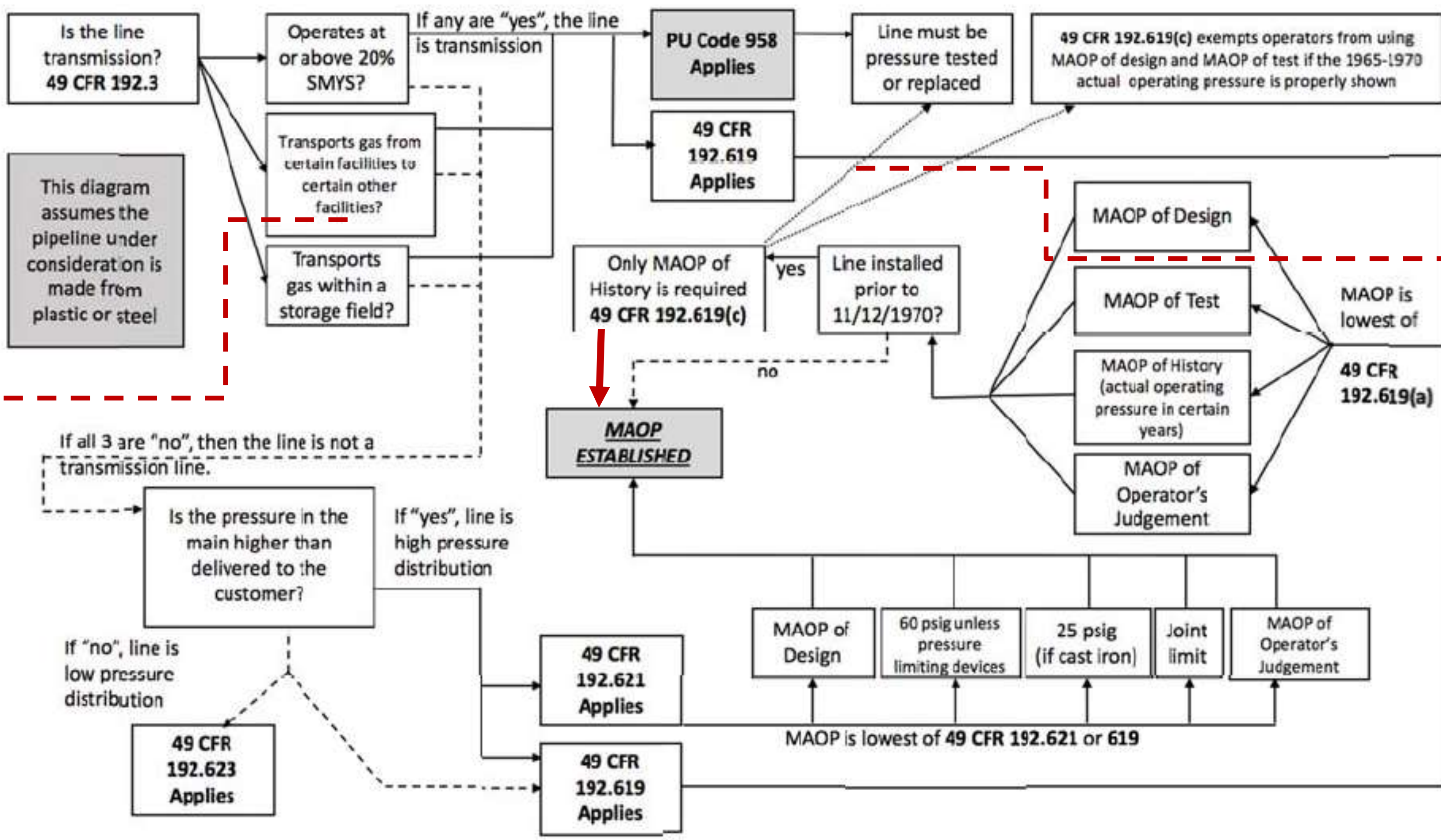
Attachment E

Corrections to ORA Figure 1

Corrections to ORA Figure 1

Figure 1: Diagram to Establish MAOP for a Plastic or Steel Pipeline

That is not downstream from a distribution center.



This line is incorrect and should be removed.

Attachment F

Utilities' Responses to SED Data Requests

Attachment F-1

Utilities' Response to SED DR-03, Q2 and Q3

PUBLIC VERSION

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(SED DATA REQUEST- 3)

Date Requested: May 31, 2016
Date Responded: June 13, 2016

QUESTION 2:

A segment by segment engineering analysis for the entire Line 1600 with any unknown pipeline characteristics identified and any assumed values detailed.

RESPONSE 2:

Some of the information provided in the attachment contains confidential information provided pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583.

As part of the Maximum Allowable Operating Pressure (MAOP) validation process each segment was analyzed to determine the appropriate MAOP based on year of installation, pipe properties, class location, test records and historical operating pressures. The segment in the attached document (SED DR 3 Q2 and Q3 L1600 SEGMENTS.pdf) highlighted in gray has an unknown wall thickness and grade and the corresponding engineered value is prefixed with a “DT” (Decision Tree) designation. In addition as described in Question 1 above, an assessment and remediation of Line 1600 has been completed using In-Line-Inspection (MFL, TFI, Caliper) and External Corrosion Direct Assessment and deemed fit for service.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(SED DATA REQUEST- 3)

Date Requested: May 31, 2016
Date Responded: June 13, 2016

QUESTION 3:

Provide a detailed analysis of all segments that have been pressure tested, with traceable, verifiable, and complete test records.

RESPONSE 3:

SDG&E and SoCalGas interpret “traceable, verifiable and complete” to mean “reliable and accurate” and respond as follows:

See response to Question 2, above. Some of the information provided in the attachment contains confidential information provided pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583.

As mentioned in SED DR 2, there are still some projects being entered into the database and once added this response will be updated.

Attachment G

TURN Responses to Utilities' Data Requests

Attachment G-1

TURN Response to Utilities' DR-03

THIRD SET OF DATA REQUESTS PROPOUNDED BY SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) AND SOUTHERN CALIFORNIA GAS COMPANY (U904G) UPON THE UTILITY REFORM NETWORK

A.15-09-013: Sempra DR 03 to TURN	
Sent: April 27, 2017	Response Date: May 12, 2017
	Responder: David Berger

DATA REQUEST NO. 1

At page 1 of the PREPARED TESTIMONY OF DAVID BERGER ON BEHALF OF THE UTILITY REFORM NETWORK (TURN) ("Berger Testimony"), Mr. Berger testifies: "Recently in California, I provided consulting services for SED [Safety Enforcement Division] in the San Bruno explosion investigation (I.12-01-007), helping to write the SED report, particularly with respect to integrity management issues." Please produce a copy of the "SED Report" referred to by Mr. Berger.

RESPONSE NO. 1:

The report prepared by the Consumer Protection and Safety Division (subsequently reorganized and named the "Safety and Enforcement Division") can be found at the following: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Natural_Gas_Pipeline/News/AgendaStaffReportreOIIPGESanBrunoExplosion.pdf

DATA REQUEST NO. 2

At page 1 of the Berger Testimony, Mr. Berger testifies: "I was also part of the team of consultants for Cycla Corporation that provided a report for SED regarding PG&E's [Pacific Gas and Electric Company's] risk assessment efforts with respect to its gas distribution system in the 2014 general rate case (GRC)." Please produce a copy of the "report for SED" referred to by Mr. Berger.

RESPONSE NO. 2:

The referenced report is attached.

DATA REQUEST NO. 3:

At pages 2-3 of the Berger Testimony, Mr. Berger testifies: "However, I recommend that even if operated as a distribution line, the company should continue to use transmission integrity management practices on Line 1600, including periodic patrols, frequent leak surveys, and above-ground markers of the pipeline." At page 15 of the Berger Testimony, Mr. Berger testifies: "Since the safety requirements for a distribution main are less stringent than for a transmission line, TURN believes that some of these requirements should be mandated on the newly derated Line 1600. The two main areas are leak survey and patrolling for third party damages." With respect to this testimony:

a. Please state whether leak surveys, periodic patrolling for third party damage, and above-ground markers of the pipeline are all of the transmission integrity management practices that TURN recommends for the de-rated Line 1600. If no, please identify any other transmission integrity management practices that TURN recommends for the de-rated Line 1600, and explain why.
b. Please state whether TURN is recommending in-line inspections for the de-rated Line 1600. If so, please identify in-line inspection tools that TURN contends would operate successfully at a pressure of 320 psig or less, explain the factual basis for your response, and produce any documents that support your response.
c. Is TURN aware of any axial magnetic flux leakage (MFL) inspection tool that would operate successfully in a pipeline at a pressure of 320 psig or less? If yes, please identify such tool by name and vendor, and produce any documents addressing its specifications.
d. Is TURN aware of any circumferential MFL inspection tool that would operate successfully in a pipeline at a pressure of 320 psig or less? If yes, please identify such tool by name and vendor, and produce any documents addressing its specifications.

RESPONSE NO. 3:

a) TURN recommends that the three listed practices should be mandated for the de-rated Line 1600; however, as many of the current transmission line integrity management safety requirements as are practical should be continued, such as but not limited to excavator outreach, repair practices, etc.
b) See 'a' above
c) See 'a' above
d) See 'a' above

Attachment H

SCGC Responses to Utilities' Data Request

Attachment H-1

SCGC Response to Utilities' DR-03

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In The Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for a Certificate of Public Convenience and Necessity for the Pipeline Safety & Reliability Project	A.15-09-013

SOUTHERN CALIFORNIA GENERATION COALITION
RESPONSE TO
THIRD SET OF DATA REQUESTS PROPOUNDED BY
SAN DIEGO GAS & ELECTRIC COMPANY AND
SOUTHERN CALIFORNIA GAS COMPANY

DATA REQUEST NO. 1

Please provide the calculations and a complete set of workpapers, as active excel workbooks, that support Table 3 on p. 9 of the Direct Testimony of Ms. Catherine E. Yap.

RESPONSE NO. 1:

Please see the attached Excel file at tab “SDG&E AAEE Diff” and supporting tabs.

Gas Demand Forecast Calcs.xlsx

DATA REQUEST NO. 2

Please provide the calculations and a complete set of workpapers, as active excel workbooks, that support Table 4 on p. 9 of the Direct Testimony of Ms. Catherine E. Yap.

RESPONSE NO. 2:

Please see the attached Excel file provided in response to Question 1 at tab “SDG&E Dec 16 AAEE” and supporting tabs.

DATA REQUEST NO. 3:

Please provide the calculations and a complete set of workpapers, as active excel workbooks, that show how Table 5 on p. 13 was derived from Table 1 on p. 6 in the Direct Testimony of Ms. Catherine E. Yap.

RESPONSE NO. 3:

Please see the Excel file that was provided in response to Question 1 at tab "SDG&E Dec 16 AAEE" and supporting tabs.

Prepared by: Catherine E. Yap
Dated: May 8, 2017

SCGC Response to Utilities' DR-03
Excel File in Response to Question 1
Tab "SDGE Elec Fore Diff"

Row									
1									
2	**Impact of Renewable Generation and Energy Efficiency Programs on Gas Demand**								
3	Column:	C	D	E	F	G	H	I	J
4		2016	2017	2018	2019	2020	2025	2030	2035
5	**California Energy Requirements by SDG&E**								
6	Electricity Demand (GWh) used in 2016 CGR[1]	19,675	19,601	19,403	19,296	19,200	19,137	18,603	18,302
7	Electricity Demand (GWh) from 2016 Update[2]	19,059	18,870	18,655	18,633	18,588	18,567	18,500	18,435
8	Difference 2016 IEPR vs 2016 CEDU (GWh)	-616	-732	-748	-664	-612	-570	-103	133
9									
10	**33% Renewables by 2020 & 50% Renewables by 2(**	25%	27%	29%	31%	33%	41%	50%	50%
11	Reduction in renewable generation (GWh)	154	198	217	206	202	236	51	-66
12	Reduction in natural gas generation (GWh)	462	534	531	458	410	334	51	-66
13	Gas Savings relative to 2016 CGR (MMcf/Yr)[3]	2773	3222	3225	2770	2497	2027	311	-402
14	Gas Savings average daily basis MMcf/d	8	9	9	8	7	6	1	-1
15									
26									
27		2016	2017	2018	2019	2020	2025	2030	2035
28	Difference 2016 IEPR vs 2016 CEDU	-3%	-4%	-4%	-3%	-3%	-3%	-1%	1%
29	Gas Savings relative to 2016 CGR (MMcf/d)	-8	-9	-9	-8	-7	-6	-1	1

Notes:

1 IEPR Electricity demand forecast from the California Energy Commission: http://www.energy.ca.gov/2015_energypolicy/documents/2016-01-27_load_serving_entity_and_Balancing_authority.php, Mid-Case LSE and Balancing Authority Forecast.xls, "form1.1c" tab. From 2027-2035 the average growth rate was used from the last five years (2022-2026) which is -0.33%.

2 CEDU Electricity demand forecast from the California Energy Commission: http://www.energy.ca.gov/2015_energypolicy/documents/2016-01-27_load_serving_entity_and_Balancing_authority.php, Mid-Case LSE and Balancing Authority Forecast.xls, "form1.1c" tab. From 2027-2035 the average growth rate was used from the last five years (2022-2026) which is -0.07%.

3 Gas savings are estimated based on the following generic assumptions for California: gas-fired peaking plants are assumed to be the marginal source for 10% of the 8,760 hours in each year(24 x 365) and combined-cycle plants are marginal in another 75% of each year. Each MWh displaced from a peaking plant saves 10 MMBtu (10 Dth, or approximately 10,000 CF) of natural gas. Each MWh displaced from a combined-cycle plant saves 7 MMBtu (7 Dth, or approximately 7,000 CF) of natural gas. A conservation program that saves 1 MWh in every hour of a year saves about 55,000 MMBtu of natural gas (8,750 hours x 10% x 10 MMBtu, plus 8,760 hours x 75% x 7 MMBtu). Conservation programs that save MWh primarily during summer peak periods

Data from the California Energy Commission: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03 ; "Committed Electricity Efficiency Conservations Savings by Planning Area and Sector", Mid CORRECTED, "STATEWIDEnonrescon-Mid Demand" tab. From 2027-2035 the average

5 growth rate was used from the last five years (2022-2026) which is 1.661%.

Data from the California Energy Commission: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03 ; Committed Gas Savings by PA-

6 RF15.xlxs. From 2027-2035 the average growth rate was used from the last five years (2022-2026) which is 1.096%.

7 Total gas savings are annual savings from equipment installed after December 31, 2015.

Ratio of Gas in Bcf to electrical energy in GWh	0.006003
Ratio of Gas in MMcf to electrical energy in G	6.0030015

produce greater natural gas savings per MWh. Similar estimates apply to renewable electric generators. This is the method used in the 2016 CGR.

SCGC Response to Utilities' DR-03
Excel File in Response to Question 1
Tab "SDGE AAEE Diff"

Difference Between SDG&E AAEE used in 2016 GRC and CEC Mid-Range AAEE used in 2016 CEDU (note 2015 IEPR uses same AAEE)

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Relative to 2015 savings from 2016 CEDU	Natural Gas (MDth)	123	238	428	668	939	1,155	1,382	1,587	1,807	2,045	2,291	2,512			
note AAEE doesn't change from 2015 IEPR	Natural Gas MMcf	120	232	419	653	918	1,129	1,351	1,552	1,767	1,999	2,239	2,456	2,692	2,951	3,235
Relative to 2015 savings	Energy (GWh, Includes lo	193.92	413.89	662.51	837.98	991.58	1162.46	1333.67	1511.40	1680.14	1846.17	2009.64	2153.36	2311.34	2480.91	2662.92
	Equv Natural Gas MMcf	873.07	1813.76	2823.72	3470.95	3988.16	4558.16	5094.91	5621.37	6079.41	6493.88	6861.49	7129.97	7414.53	7702.46	7992.74
	Percent RPS	25%	27%	29%	31%	33%	35%	36%	38%	40%	41%	43%	45%	47%	48%	50%
	Percentage Nat Gas	75%	73%	71%	69%	67%	65%	64%	62%	60%	59%	57%	55%	53%	52%	50%
	Gas Savings MMcfd	654.80	1324.05	2004.84	2394.95	2672.07	2977.35	3242.32	3482.86	3664.45	3805.13	3902.57	3932.70	3962.19	3983.64	3996.37
	Combined MMcf	775	1,557	2,423	3,048	3,590	4,106	4,593	5,034	5,431	5,804	6,142	6,389	6,654	6,935	7,231

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
From SDG&E Response to SCGC-12, Q.12.7.1.																
Combined natural gas savings		mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf
		313	492	744	1,033	1,290	1,587	1,916	2,252	2,601	2,704	2,738	2,908	3,005	3,065	3,157
Difference CEC Mid-Range AAEE vs SDG&E		462	1064	1679	2015	2300	2519	2677	2783	2830	3100	3404	3481	3649	3870	4075
		1	3	5	6	6	7	7	8	8	8	9	10	10	11	11
Estimated separation between gas and elec	gas	72	159	290	432	588	693	787	858	921	1068	1241	1338	1476	1647	1823
	elec	390	905	1389	1583	1712	1827	1890	1925	1910	2032	2163	2143	2173	2223	2252
	gas	0	0	1	1	2	2	2	2	3	3	3	4	4	5	5
	elec	1	2	4	4	5	5	5	5	5	6	6	6	6	6	6

Attachment H-2

SCGC Response to Utilities' DR-05, Q5, Q6, Q9, Q10, Q16

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In The Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for a Certificate of Public Convenience and Necessity for the Pipeline Safety & Reliability Project	A.15-09-013

SOUTHERN CALIFORNIA GENERATION COALITION
RESPONSE TO
FIFTH SET OF DATA REQUESTS PROPOUNDED BY
SAN DIEGO GAS & ELECTRIC COMPANY AND
SOUTHERN CALIFORNIA GAS COMPANY

DATA REQUEST NO. 1

The Yap Testimony at page 41, lines 22-25 states: "Having a realistic picture of minimum EG [electric generator] requirements identifies the portion of the EG loads on the SDG&E system that may be safely curtailed during the winter months if the prediction regarding severe cold weather are communicated to the CAISO [California Independent System Operator] in a timely manner." Please provide SCGC's proposed procedure that details the substance and timing of the referenced communications with CAISO. Also, what are the ramifications/adverse consequences if the CAISO is not notified in time regarding minimum EG requirements? Does this coordination assist in the event gas Line 3010 is out of service?

RESPONSE NO. 1:

SCGC expects that the appropriate staff at the CAISO would determine the amount of gas-fired generation in SDG&E's service territory that is required during the winter months to meet reliability standards. SCGC expects that the CAISO staff would coordinate with appropriate staff from the Applicants and from the CPUC in performing this assessment. SCGC expects that the CAISO staff would update its assessment periodically as appropriate.

SCGC is aware that the System Operator is in daily communications with the CAISO through the sharing of forecasts and information regarding EG plant dispatch in the Applicants'

Subject to and without waiving SCGC's objection, SCGC's response to Data Request No.5 is as follows: Ms. Yap is unaware of a CAISO tariff provision that requires that the "CAISO and the Commission collaborate on studies of the impact on electric reliability of a potential failure of Line 3010 or the Moreno Compressor Station that impact electric reliability." Nevertheless, Ms. Yap recommends a coordinated effort with the CAISO and Commission staff that would lead to a better understanding of the consequences of the failure of Line 3010 without the expectation that physical gas system mitigation would be required. Such a study would provide an opportunity to examine alternatives that might work to reinforce the electric system without costing gas ratepayers billions of dollars in future potentially stranded SoCalGas/SDG&E revenue requirement. A co-benefit could be enhancements to the electric system that would assist California in meeting statutorily mandated environmental objectives.

DATA REQUEST NO. 5:

The Yap Testimony at page 55, lines 4-9, states: "Many existing asynchronous generators such as wind and solar generators may already have inverters that are capable of producing reactive power even though they were not required by Order 827 to provide reactive power. There are already nearly 700 MW of wind and solar generating plants connected to SDG&E's East County and Ocotillo substations that are located to the west of the Imperial Valley substation but east of the San Diego metropolitan area. With proper control software and telemetering these existing plants could become available to produce reactive power if they do not already have the requisite equipment." (Footnote omitted). With respect to such testimony:

a. Please provide Power System Studies that support this claim and their effectiveness in mitigating the voltage stability issue in the southern SCE system and northern SDG&E system.
b. Please provide generator data sheets from identified generation connected to East County or Ocotillo Substations that show whether such generation has "inverters that are capable of producing reactive power" and "proper control software and telemetering."
c. If the statement "[m]any existing asynchronous generators such as wind and solar generators may already have inverters that are capable of producing reactive power" is other than speculation, please identify each of the "wind and solar generating plants connected to SDG&E's East County and Ocotillo substations" that has such inverters.

d. To the extent that the referenced generation does not have such inverters and/or the "proper control software and telemetering," estimate the cost of equipping such generation with such equipment.

Please state all facts that support your responses, produce all workpapers and documents that support your responses, and identify the person(s) that prepared these responses.

RESPONSE NO. 5:

a. SCGC did not conduct any such Power System studies.
b. SCGC does not have access to the generator data sheets
c. SCGC has not identified specific plants
d. SCGC has not assessed the cost for specific plants

DATA REQUEST NO. 6:

The Yap Testimony at page 55, states: "Thus, solar arrays connected at primary voltage or above in the local area should be capable of producing and absorbing reactive power, taking on a role that has been previously provided by gas-fired generators in SDG&E's area. Wind generators that use a similar inverter technology would be expected to have the same ability to produce reactive power that would meet CAISO requirements." Please explain how intermittency and variability concerns associated with these resources is mitigated.

RESPONSE NO. 6:

Using storage in conjunction with renewables would address intermittency and variability concerns.

DATA REQUEST NO. 7:

The Yap Testimony at page 56, line 11, states: "Since reactive power does not travel electrically over great distances, as described by the Applicants, the generator or other source of reactive power must be located 'within the Import cut-plane and west of Imperial Valley'. As noted previously, wind and solar plants connected to SDG&E's East County and Ocotillo substations have the potential to inject reactive power west of Imperial Valley substation." (Footnote omitted). Please provide Power System Studies that demonstrate that reactive support connected to East County and Ocotillo Substations would mitigate voltage stability concerns in the northern part of SDG&E's system and the southern part of Southern California Edison's (SCE's) system.

Also, please clarify your understanding of the "Cut-plane," and the generators you have mentioned relative to the cut-plane.

RESPONSE NO. 7:

SCGC has not performed the referenced Power System studies. SCGC's understanding of the term "cut-plane" is that the term has the meaning ascribed by the Applicants in their Response 13.7.2 to SCGC Data Request 13, Question 13.7.2. Thus, the cut plane is demarked by a north-south line through Imperial Valley substation. The referenced generators are connected to the Ocotillo and East County substations which are located to the west of what the Applicants call the "cut-plane" and Imperial Valley substation.

DATA REQUEST NO. 8:

The Yap Testimony at page 64, Section 5.5.2, states: "Under this alternative the capacity of the IID S-Line would be doubled from 407 MW to 800 MW by adding a second circuit on the line." With respect to the referenced alternative, discussed generally in the Yap Testimony, Section 5.5.2 and Attachment C, please respond to the following questions:

a. Who does SCGC contend would be the sponsor of such a project?
b. Which ratepayers would pay the cost of upgrading the IID S-Line?
c. If SCGC contends that the cost would be split between IID and CAISO ratepayers, please provide documentation regarding the split cost allocation mechanism that will assist this process.
d. The Yap Testimony at 66 states: "The capacity of the S-Line could be increased from 407 MW to 800 MW for a cost of about $38 million." Please provide all workpapers and supporting documents supporting this cost estimate.
e. Which regulatory agencies would need to approve such a project and state the permitting, environmental mitigations and impacts related to this project?
f. What are the consequences to the CAISO and IID electric transmission systems of the proposed project? Please produce Power System Studies regarding implementation of the proposed project.
g. Please identify post-project completion, the next contingency/system limitation.

RESPONSE NO. 8:

a. SCGC expects that such a project would be the result of coordination between the CAISO and IID.

b. Please see the answer to Question 8.a.

c. Please see the answer to Question 8.a.

d. The sentence quoted in Data Request No. 8.d does not appear on page 66 of Ms. Yap's direct testimony. However, the sentence quoted in Data Request No. 8.d does appear on page 66 of Ms. Yap's direct testimony. Assuming that the Applicants intend their question to address that sentence, SCGC responds as follows: The estimated cost of $38 million is a high level budgetary estimate based on per mile cost for 230 kV line construction.

e. SCGC objects to Data Request No. 8.e. insofar as it calls for speculation about the result of coordination between the CAISO and IID about the project. Subject to and without waiving SCGC's objection, SCGC provides the following response: SCGC expects entities would be involved as appropriate to review the environmental impacts, which should be relatively limited given that the project involves upgrading an existing transmission line.

f. The result would be a significant increase in power import capability as described in Ms. Yap's testimony at pages 64-65. No power system studies were prepared.

g. Please see Yap testimony Attachment C at 9.

DATA REQUEST NO. 9:

The Yap Testimony at page 66 states: "the expectation in this alternative would be to utilize the SDG&E interconnection with CFE to allow power to flow north from CFE's Presidente Juarez plant to provide reactive as well as active power to supplement SDG&E's needs in the event of a loss of Line 3010 or a Moreno Compressor Station outage." With respect to this testimony:

a. Please admit that SCGC and its agents have not conducted any Power System Studies that support this claim.

b. Please produce any Power System Studies and any other documents that support this claim.

c. Please state the generating capacity of CFE's Presidente Juarez power plant, and the extent to which it was utilized each day over the past three years. Identify the sources of all facts in your response and produce all documents supporting your response.

d. Please admit that there currently is no "emergency coordination agreement with CENACE which would provide for CENACE to dispatch CFE's Presidente Juarez power plant to provide voltage support to SDG&E in addition to meeting CFE's local loads." If you do not so admit, state all facts and produce all documents that support your response.

e. Describe all communications that SCGC has had with CFE or CENACE regarding such an emergency coordination agreement, and produce any written documentation thereof.

f. The Yap Testimony at 67 states: "The coordination agreement could take the form of a mutual aid agreement, in which case the cost might be limited to agreeing to reimburse the assisting party for incremental costs, such as increased fuel burn by less efficient powerplants, that are incurred while providing the assistance to the party in need." If the statement that the "cost might be limited to agreeing to reimburse the assisting party for incremental costs" is other than speculation, please state all facts that support such statement, produce all documents that support such statement, and identify the person responsible for preparing this response.

RESPONSE NO. 9:

a. SCGC has not performed the referenced power system studies. However, the WECC Path 42 is rated at 800 MW. Power system studies would have been conducted at the time the 800 MW limit was established.

b. SCGC has not performed the referenced power system studies.

c. The generation capacity for the Presidente Juarez power plant is provided below. The source is a WECC 2019 Heavy Summer base case. Base case designation 19HS-r8.sav:

HS19-r9.sav Unit Designation	Modeled Maximum Capacity (MVA)	Interconnected at:
CCBC-U1	215	Presidente Juarez 230 kV
CCBC-U2	109.7	Presidente Juarez 230 kV
PJZ-U5	177.7	Presidente Juarez 230 kV
PJZ-U6	177.7	Presidente Juarez 230 kV
PJZ-U7	217	Presidente Juarez 230 kV
PJZ-U8	290	Presidente Juarez 230 kV
PJZ-U9	290	Presidente Juarez 230 kV
TTI-U1	45.3	Presidente Juarez 115 kV
TTI-U2	45.3	Presidente Juarez 115 kV
Total	**1567.7**	

d. There is no current agreement.
e. SCGC has not had communications with CFE or CENACE.
f. The statement that the "cost might be limited to agreeing to reimburse the assisting party for incremental costs" is based on the assumption that a coordination agreement with CENACE took the form of a mutual aid agreement.

DATA REQUEST NO. 10:

Regarding the Yap Testimony at Attachment C section 4.2, please provide total cost of the multiple number of synchronous condensers that would be needed from Pacific Gas and Electric Company (PG&E), SCE, and SDG&E based on the Power System Studies conducted. Also provide the Power System Studies and technical assumptions to maximize North to South power flow.

RESPONSE NO. 10:

SCGC did not perform a power system study to determine the "multiple number of synchronous condensers that would be needed from Pacific Gas and Electric Company (PG&E), SCE, and SDG&E," so SCGC doe not have acost estimate for the "multiple number of synchronous condensers that would be needed from Pacific Gas and Electric Company (PG&E), SCE, and SDG&E."

DATA REQUEST NO. 11:

Please identify the witness who will testify with respect to Attachment C to the Yap Testimony.

RESPONSE NO. 11:

Catherine E. Yap and Brian Rahman

DATA REQUEST NO. 12:

The Yap Testimony, Attachment C at 4 states: "Of the total gas generation resources listed above for 2018 of 3,774 MW, a total of 1,080 MW of these thermal resources are located in Imperial Valley, outside the cut plane that defines the SDG&E load pocket. It is assumed this generation will remain available during a gas supply interruption to SDG&E load as these facilities are not supplied through the SDG&E system." Please identify the generation assumed not to be

a. Please produce the referenced “simulation of re-dispatched generation.”

b. Please identify each instance in the “discussion above” that “assumed a maximum transfer across the SONGS interface of 580 MW.”

RESPONSE NO. 15:

a. The following steps were taken in modifying the CAISO TPP 2016-2017 SDG&E Bulk System base case to establish a 580 MW flow from SCE into the SDG&E area at the SONGS interface:

1. Enable the Swing bus for SDG&E. It was found to be off line.

2. Modify the area interchange between SCE and SDG&E to be increased by 660 MW.

3. Increase generation in SCE, PG&E, and AZ by 500MW, 100MW, and 60MW respectively.

b. The “discussion above” that “assumed a maximum transfer across the SONGS interface of 580 MW” is the discussion in Ms. Yap’s testimony Attachment C, section 4.1 (pp. 8-9).

DATA REQUEST NO. 16:

The Yap Testimony, Attachment C at 9 discusses the potential “need for reactive support in the SONGS area such as an additional synchronous condenser.”

a. Please produce Power System Studies demonstrating the need for the additional synchronous condenser.

b. Please identify where such an additional synchronous condenser would be located and its size.

c. Please produce Power System Studies showing the impact of the additional synchronous condenser on the CAISO and IID systems.

RESPONSE NO. 16:

SCGC objects to Data Request No. 16 as unduly burdensome insofar as it misconstrues Ms. Yap’s testimony Attachment C at 9 as asserting that there is a need for an additional synchronous condenser in the SONGS area. Ms. Yap’s testimony Attachment C at 9 as does not contain such an assertion. The complete sentence from Ms. Yap’s testimony Attachment C at 9 that contains the phrase quoted in Data Request No. 16 is as follows: “This may require the need for reactive support in the SONGS area such as an additional synchronous condenser.”

Subject to and without waiving SCGC’s objection, SCGC provides the following response: SCGC did not perform a power system study.

Prepared by: Catherine E. Yap and Brian Rahman
Dated: May 19, 2017

Attachment H-3

SCGC Response to Utilities' DR-04, Q10 and Q26

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In The Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for a Certificate of Public Convenience and Necessity for the Pipeline Safety & Reliability Project	A.15-09-013

SOUTHERN CALIFORNIA GENERATION COALITION
RESPONSE TO
FOURTH SET OF DATA REQUESTS PROPOUNDED BY
SAN DIEGO GAS & ELECTRIC COMPANY AND
SOUTHERN CALIFORNIA GAS COMPANY

DATA REQUEST NO. 1

For Table 2 in the Phase One Direct Testimony of Catherine E. Yap ("Yap Testimony") at 7-8, please produce all underlying workpapers and supporting documents.

RESPONSE NO. 1:

Please see the Excel file provided in response to SDG&E/SoCalGas' Third Data Request, Question 1 at tab "SDG&E Elec Fore Diff" and supporting tabs.

DATA REQUEST NO. 2

The Yap Testimony at 8 states: "Table 2 shows a three to four percent decline in net energy usage each year from 2016 to 2025, which translates into an 8 to 9 MMcf/d decline in natural gas usage through 2019 and a 6 to 7 MMcf/d decline in natural gas usage from 2020 through 2025, falling off somewhat after that." Please state all facts that support this testimony, and produce all workpapers and documents that support this testimony.

RESPONSE NO. 2:

Please see the response to Question 1.

interfere with the startup of LNG receipts at the terminal in the unlikely event that natural gas prices changed enough to make LNG imports at Costa Azul economic."

DATA REQUEST NO. 10:

Is SCGC aware of any analysis, studies, consideration, or potential commercial interest in modifying the Energia Costa Azul (ECA) liquefied natural gas (LNG) facility to include liquefaction and export capabilities? Please state all facts that support your response, produce all workpapers and documents that support your response, and identify the person(s) that prepared this response.

RESPONSE NO. 10:

The Sempra Energy 2016 10K Report presents Sempra Energy's characterization of how the company is considering the possible expansion at the existing Energia Costa Azul LNG facility to provide export capability. There appear to be countervailing considerations. See Sempra Energy 2016 Form 10-K Report, pages 42-43.

DATA REQUEST NO. 11:

Given the existing pipeline infrastructure in Mexico, in the event that ECA is converted to an export capable facility, will such conversion improve, cause no change or decrease the commercial competitiveness of the option of importing gas into San Diego via the Mexico pipeline path compared gas transported across the Applicants pipeline network? For this scenario, will the price for transporting gas along the Mexico path increase, decrease or stay the same?

Please state all facts that support your response, produce all workpapers and documents that support your response, and identify the person(s) that prepared this response.

RESPONSE NO. 11:

SCGC objects to Data Request No. 11 as unduly burdensome insofar as it reaches beyond the scope of Catherine E. Yap's direct testimony on behalf of SCGC in A.15-09-013. Ms. Yap did not testify about the commercial competitiveness of the option of importing gas into San Diego via the Mexico pipeline path compared gas transported across the Applicants' pipeline network or about factors that might affect the price for transporting gas along the "Mexico path," apparently meaning the North Baja-Gasoducto Rosarito-TGN path.

Subject to and without waiving SCGC's objections, SCGC's response to Data Request the Gulf Coast region of the U.S. as well as Peru. Thus, some cargo ships are likely to be near LNG facilities either on an inbound or outbound basis. An inbound ship could be loaded immediately to meet the core/system operator emergency requirements. Outbound cargos could be redirected if the purchaser is willing to sell the shipment to the core/system operator and thus accept a delay in receiving its LNG shipment (assuming there would be compensation for this) and the ship has not gone past a point where it reach Costa Azul within five days. Inbound ships would be expected to load in about a day assuming that the ship maintains a heel so that the equipment is already precooled.

DATA REQUEST NO. 26:

The Yap Testimony at 33 states: "Three entities hold LNG storage tank rights at Costa Azul: IEnova LNG (50 percent share), Shell Mexico (25 percent share), and Gazprom Mexico (25 percent share)." Did SCGC contract any of these entities regarding their interest in and price for selling their LNG storage tank rights at Costa Azul? If so, please produce copies of all written communications, identify all oral communications, and state the terms of any proposed contract.

RESPONSE NO. 26:

No. The April 22, 2016, Joint Comments of the Alliance for Retail Energy Markets and Shell Energy North America (US), L.P. on the Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin stated at page 7 that "Gas supply solutions could take the form of additional imports at Otay Mesa, possibly from LNG supplies. The cost of using LNG delivered at Otay Mesa as a "peaking gas supply" would likely be lower than the cost of rolling blackouts for the number of days identified in the Reliability Plan over the course of the summer." This suggests that at least Shell Mexico would be interested in providing LNG related services.

DATA REQUEST NO. 27:

The Yap Testimony at 36 states: "At the previously posted 2011 rate for storage at Energia Costa Azul, a year's worth of storage for one-half of a tank of LNG would cost $58 million. However, given the competition among the three suppliers, IEnova LNG, Shell Mexico, and Gazprom Mexico, and the lack of activity at the Energia Costa Azul LNG terminal, it is likely that the cost of storage would be deeply discounted. Thus, I would expect that the storage costs for the one-

Attachment I

Energy Almanac

http://www.energy.ca.gov/almanac/electricity_data/electricity_gen_1983-current.xlsx

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh
Grand Total: California Generation plus Net Imports *	**267,386**	**274,389**	**279,671**	**290,082**	**289,158**	**298,316**	**304,909**	**307,450**	**298,449**	**291,184**	**293,779**	**302,320**	**296,250**	**297,062**	**295,405**
Total Hydroelectric	24,988	31,357	36,321	34,490	40,263	48,559	27,106	24,460	28,540	34,189	42,731	27,459	24,097	16,477	13,993
Large Hydroelectric	*20,144*	*26,003*	*30,325*	*28,945*	*33,334*	*40,952*	*22,640*	*19,887*	*23,659*	*28,483*	*35,682*	*22,737*	*20,319*	*13,739*	*11,569*
Small Hydroeletric	*4,844*	*5,354*	*5,996*	*5,545*	*6,928*	*7,607*	*4,466*	*4,573*	*4,880*	*5,706*	*7,049*	*4,723*	*3,778*	*2,737*	*2,423*
Nuclear	33,294	34,353	35,594	30,241	36,155	32,036	35,698	32,482	31,509	32,214	36,666	18,491	17,860	17,027	18,525
In-State Coal	4,041	4,275	4,269	4,086	4,283	4,190	4,217	3,977	3,735	3,406	3,120	1,580	1,018	1,011	538
Oil	379	87	103	127	148	134	103	92	67	52	36	48	38	45	54
Natural Gas	116,381	92,723	94,474	105,266	97,100	109,195	120,467	123,062	117,294	109,886	91,221	121,877	121,040	121,995	117,489
Geothermal	13,525	13,396	13,329	13,494	13,292	13,093	13,084	12,907	12,907	12,740	12,685	12,733	12,479	12,186	11,994
Biomass	5,762	6,197	6,094	6,082	6,078	5,863	5,764	5,927	6,111	5,981	6,051	6,201	6,550	6,776	6,362
Wind	3,242	3,546	3,316	4,258	4,084	4,902	5,570	5,724	6,249	6,172	7,598	9,242	11,964	13,074	12,180
Solar PV	3	2	2	2	2	2	2	3	13	84	211	964	3,656	8,962	12,600
Solar Thermal	834	848	757	739	658	614	666	730	841	879	889	867	686	1,624	2,446
Other	12	10	14	9	12	15	15	14	13	12	13	14	15	16	14
Direct Coal Imports**	23,699	23,653	23,148	24,504	24,114	14,452	14,417	14,463	13,556	13,119	13,032	9,716	11,824	12,370	11,837
Other Imports***	41,227	63,941	62,253	66,785	62,967	65,263	77,799	83,608	77,615	72,451	79,525	93,126	85,022	85,500	87,374
Total In-State Generation	**202,460**	**186,796**	**194,270**	**198,793**	**202,076**	**218,601**	**212,692**	**209,378**	**207,278**	**205,614**	**201,223**	**199,478**	**199,403**	**199,192**	**196,194**
Non-Commercial In-State Generation	**67,208**	**70,511**	**76,202**	**71,235**	**83,222**	**91,803**	**83,116**	**79,357**	**81,336**	**86,524**	**94,442**	**71,493**	**69,282**	**61,499**	**62,553**
Total Hydroelectric	21,449	26,395	29,984	28,992	33,210	39,979	23,204	20,676	23,686	28,166	34,437	22,693	20,506	14,041	12,007
Large Hydroelectric	*17,806*	*22,636*	*25,903*	*25,230*	*28,582*	*35,000*	*20,155*	*17,526*	*20,392*	*24,336*	*29,759*	*19,505*	*17,906*	*12,052*	*10,228*
Small Hydroeletric	*3,642*	*3,759*	*4,081*	*3,762*	*4,628*	*4,979*	*3,049*	*3,150*	*3,294*	*3,830*	*4,679*	*3,187*	*2,600*	*1,990*	*1,778*
Nuclear	33,294	34,353	35,594	30,241	36,155	32,036	35,698	32,482	31,509	32,214	36,666	18,491	17,860	17,027	18,525
In-state Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oil	123	43	41	51	58	51	53	53	45	35	30	29	28	30	31
Natural Gas	11,344	8,564	9,387	10,803	12,797	18,744	23,172	25,169	25,068	24,908	22,053	28,811	29,436	28,833	30,600
Geothermal	996	1,150	1,190	1,140	997	970	975	947	903	846	858	875	817	863	837
Biomass	-	4	4	6	2	20	12	28	18	38	37	39	20	11	8
Wind	-	-	-	-	-	-	-	-	102	306	286	282	259	286	137
Solar PV	3	2	2	2	2	2	2	3	5	11	73	273	357	407	408
Solar Thermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-
Commercial In-State Generation	**135,252**	**116,285**	**118,069**	**127,558**	**118,854**	**126,799**	**129,576**	**130,021**	**125,942**	**119,090**	**106,781**	**127,986**	**130,122**	**137,693**	**133,641**
Total Hydroelectric	3,539	4,962	6,337	5,498	7,052	8,579	3,902	3,784	4,854	6,023	8,294	4,767	3,591	2,435	1,986
Large Hydroelectric	*2,338*	*3,367*	*4,422*	*3,714*	*4,753*	*5,952*	*2,486*	*2,361*	*3,267*	*4,147*	*5,924*	*3,231*	*2,413*	*1,688*	*1,341*
Small Hydroeletric	*1,202*	*1,595*	*1,915*	*1,783*	*2,300*	*2,628*	*1,416*	*1,423*	*1,586*	*1,876*	*2,370*	*1,535*	*1,179*	*748*	*645*
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
In-state Coal	4,041	4,275	4,269	4,086	4,283	4,190	4,217	3,977	3,735	3,406	3,120	1,580	1,018	1,011	538
Oil	256	44	62	76	90	83	51	39	22	17	6	20	11	15	23

Attachment I
Energy Almanac

Natural Gas	105,037	84,160	85,086	94,463	84,304	90,451	97,295	97,894	92,226	84,978	69,169	93,066	91,604	93,161	86,889
Geothermal	12,528	12,246	12,139	12,354	12,295	12,123	12,109	11,960	12,004	11,894	11,826	11,858	11,662	11,323	11,156
Biomass	5,762	6,193	6,090	6,076	6,076	5,842	5,752	5,899	6,093	5,942	6,014	6,162	6,530	6,765	6,354
Wind	3,242	3,546	3,316	4,258	4,084	4,902	5,570	5,724	6,147	5,865	7,312	8,960	11,706	12,788	12,043
Solar PV	-	-	-	-	-	-	-	0	8	73	138	692	3,300	8,554	12,192
Solar Thermal	834	848	757	739	658	614	666	730	841	879	889	867	686	1,624	2,446
Other	12	10	14	9	12	15	15	14	13	12	13	14	14	16	14
Energy Exports	**14,854**	**6,534**	**6,026**	**4,825**	**5,685**	**5,056**	**5,586**	**5,064**	**4,629**	**5,054**	**5,146**	**4,974**	**3,281**	**11,450**	**10,737**
Northwest	5,846	1,020	1,471	1,532	2,061	2,518	2,620	2,242	1,871	1,809	1,133	761	809	132	132
Southwest	9,007	5,514	4,555	3,292	3,623	2,539	2,966	2,822	2,759	3,245	4,013	4,213	2,472	11,317	10,605
Energy Imports	**79,780**	**94,128**	**91,427**	**96,113**	**92,766**	**84,771**	**97,802**	**103,136**	**95,800**	**90,624**	**97,703**	**107,816**	**100,127**	**109,320**	**109,947**
Northwest	12,672	28,206	23,775	22,363	22,347	22,321	27,289	26,201	21,800	26,486	36,352	40,231	35,897	37,393	35,932
Southwest	67,107	65,921	67,652	73,750	70,419	62,450	70,514	76,935	74,000	64,138	61,351	67,585	64,230	71,927	74,015
Net Energy Imports (%)	**24%**	**32%**	**31%**	**31%**	**30%**	**27%**	**30%**	**32%**	**31%**	**29%**	**32%**	**34%**	**33%**	**33%**	**34%**
Net Energy Imports	**64,926**	**87,594**	**85,401**	**91,289**	**87,081**	**79,714**	**92,217**	**98,072**	**91,171**	**85,570**	**92,557**	**102,842**	**96,846**	**97,870**	**99,210**
Northwest	6,826	27,186	22,303	20,831	20,286	19,803	24,669	23,959	19,929	24,677	35,219	39,470	35,088	37,261	35,800
Southwest	58,100	60,408	63,097	70,458	66,795	59,911	67,547	74,113	71,241	60,893	57,338	63,372	61,758	60,609	63,410

* **Note:** Note: The data in this table is based on corrections and updates as of July 27, 2016.

** **Note:** The Direct Coal Imports category is based on reported ownership shares and contractual arrangements for power purchases by California utilities. Due to legislative changes required by Assembly Bill 162 (2009) and to simplify the characterization of coal power generation, only Utah's Intermountain Power Project and Nevada's Mohave Generation Station (closed as of 2006) are included in the reported Direct Coal Imports for 1983 through 2015 on this table. A more detailed analysis of the role of coal-based power generation within California is outside the scope of this table. The California Air Resources Board is currently undertaking the task of identifying the fuel source of all imported power into California. When comparing coal and other power imports over time, the best approach is to compare the combined value of Net Energy Imports.

*** **Note**: In this tabulation, generation located physically out-of-state is included in the energy imports category. The energy imports and exports include all electricity flows in and out of the state as reported by four California Balancing Authorities: California Independent System Operator, Los Angeles Department of Water and Power, Imperial Irrigation District, and Balancing Area of Northern California plus generation at six out-of-state power plants that are within one or more of these Balancing Authorities' control areas but are physically located outside California. These plants include Intermountain Power Plant (coal) in Utah, Mohave Generation Station (coal) in Nevada (now closed), Terra-Gen Dixie Valley plant (geothermal) and Desert Star Plant (natural gas) in Nevada, Termoelectrica de Mexicali Plant and InterGen's La Rosita Plant (natural gas) both of which are in Mexico. Power generated by these plants is not reported

Attachment J

Utilities' Revisions of SCGC-01 Tables

Attachment J-1

SCGC-01 Revised Table 2

Attachment J.1
SCGC-01 Revised Table 2 Excel
"SDGE Elec Fore Diff"

Row									
1									
2	**Impact of Renewable Generation and Energy Efficiency Programs on Gas Demand**								
3	Column:	C	D	E	F	G	H	I	J
4		2016	2017	2018	2019	2020	2025	2030	2035
5	**California Energy Requirements by SDG&E**								
6	Electricity Demand (GWh) used in 2016 CGR[1]	19,675	19,601	19,403	19,296	19,200	18,932	18,603	18,302
7	Electricity Demand (GWh) from 2016 Update[2]	19,059	18,870	18,655	18,633	18,588	18,613	18,547	18,481
8	Difference 2016 IEPR vs 2016 CEDU (GWh)	-616	-732	-748	-664	-612	-319	-56	179
9									
10	**33% Renewables by 2020 & 50% Renewables by 20**	25%	27%	29%	31%	33%	41%	50%	50%
11	Reduction in renewable generation (GWh)	154	198	217	206	202	132	28	-90
12	Reduction in natural gas generation (GWh)	462	534	531	458	410	187	28	-90
13	Gas Savings relative to 2016 CGR (MMcf/Yr)[3]	2773	3222	3225	2770	2497	1134	170	-543
14	Gas Savings average daily basis MMcf/d	8	9	9	8	7	3	0	-1
15									
26									
27		2016	2017	2018	2019	2020	2025	2030	2035
28	Difference 2016 IEPR vs 2016 CEDU	-3%	-4%	-4%	-3%	-3%	-2%	0%	1%
29	Gas Savings relative to 2016 CGR (MMcf/d)	-8	-9	-9	-8	-7	-3	0	1

Notes:

1 IEPR Electricity demand forecast from the California Energy Commission: http://www.energy.ca.gov/2015_energypolicy/documents/2016-01-27_load_serving_entity_and_Balancing_authority.php, Mid-Case LSE and Balancing Authority Forecast.xls, "form1.1c" tab. From 2027-2035 the average growth rate was used from the last five years (2022-2026) which is -0.33%.

2 CEDU Electricity demand forecast from the California Energy Commission: http://www.energy.ca.gov/2015_energypolicy/documents/2016-01-27_load_serving_entity_and_Balancing_authority.php, Mid-Case LSE and Balancing Authority Forecast.xls, "form1.1c" tab. From 2027-2035 the average growth rate was used from the last five years (2022-2026) which is -0.07%.

3 Gas savings are estimated based on the following generic assumptions for California: gas-fired peaking plants are assumed to be the marginal source for 10% of the 8,760 hours in each year(24 x 365) and combined-cycle plants are marginal in another 75% of each year. Each MWh displaced from a peaking plant saves 10 MMBtu (10 Dth, or approximately 10,000 CF) of natural gas. Each MWh displaced from a combined-cycle plant saves 7 MMBtu (7 Dth, or approximately 7,000 CF) of natural gas. A conservation program that saves 1 MWh in every hour of a year saves about 55,000 MMBtu of natural gas (8,750 hours x 10% x 10 MMBtu, plus 8,760 hours x 75% x 7 MMBtu). Conservation programs that save MWh primarily during summer peak periods

5 Data from the California Energy Commission: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03 ; "Committed Electricity Efficiency Conservations Savings by Planning Area and Sector", Mid CORRECTED, "STATEWIDEnonrescon-Mid Demand" tab. From 2027-2035 the average growth rate was used from the last five years (2022-2026) which is 1.661%.

6 Data from the California Energy Commission: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03 ; Committed Gas Savings by PA-RF15.xlxs. From 2027-2035 the average growth rate was used from the last five years (2022-2026) which is 1.096%.

7 Total gas savings are annual savings from equipment installed after December 31, 2015.

Ratio of Gas in Bcf to electrical energy in GWh	0.006003
Ratio of Gas in MMcf to electrical energy in G'	6.0030015

produce greater natural gas savings per MWh. Similar estimates apply to renewable electric generators. This is the method used in the 2016 CGR.

Attachment J-2

SCGC-01 Revised Table 3

Attachment J.2
SCGC-01 Revised Table 3
"SDGE Dec 16 AAEE"

Additional Achievable Energy Efficiency Savings For SDG&E Service Territory

2016 CED Updated Forecast, Mid AAEE Savings Scenario (Consistent with Mid Demand Baseline Forecast)

Sector	Savings Category	Type	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	Emerging Technologies	Peak (MW, Customer Side)	0.00	0.36	0.82	1.28	1.82	2.62	3.63	4.87	6.33	8.01	9.89	11.94	14.13			
Residential	Other Program Measures	Peak (MW, Customer Side)	0.00	10.13	20.41	26.84	29.41	29.36	30.87	31.59	31.27	30.91	30.80	30.68	29.99			
Residential	Appliance Standards	Peak (MW, Customer Side)	11.09	24.49	35.93	54.09	68.35	82.37	96.08	110.01	123.58	136.04	148.07	159.60	171.10			
Residential	Building Standards	Peak (MW, Customer Side)	0.00	0.00	1.07	3.61	6.34	10.08	14.80	19.39	23.88	28.24	32.51	36.70	40.83			
Residential	Total	Peak (MW, Customer Side)	11.09	34.98	58.24	85.82	105.93	124.43	145.39	165.86	185.06	203.21	221.27	238.93	256.06			
Commercial	Emerging Technologies	Peak (MW, Customer Side)	0.00	1.07	2.53	3.32	4.31	5.56	6.53	7.61	9.77	12.25	14.98	18.01	21.34			
Commercial	Other Program Measures	Peak (MW, Customer Side)	0.00	13.47	27.72	39.07	50.80	62.71	74.64	86.78	100.46	115.00	130.24	145.98	161.90			
Commercial	Appliance Standards	Peak (MW, Customer Side)	0.00	0.43	1.72	10.50	14.09	17.52	20.75	23.87	26.63	28.59	30.42	32.09	33.11			
Commercial	Building Standards	Peak (MW, Customer Side)	0.00	0.00	0.11	0.57	1.02	1.59	2.49	3.35	4.32	5.61	6.87	8.09	9.28			
Commercial	Total	Peak (MW, Customer Side)	0.00	14.97	32.07	53.45	70.22	87.38	104.40	121.61	141.18	161.46	182.51	204.17	225.63			
Industrial-Manufacturing	Emerging Technologies	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Manufacturing	Other Program Measures	Peak (MW, Customer Side)	0.00	0.49	0.98	1.46	1.94	2.41	2.87	3.33	3.79	4.23	4.68	5.12	5.56			
Industrial-Manufacturing	Appliance Standards	Peak (MW, Customer Side)	0.00	0.00	0.17	0.34	0.51	0.68	0.84	1.01	1.17	1.32	1.48	1.64	1.79			
Industrial-Manufacturing	Building Standards	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Manufacturing	Total	Peak (MW, Customer Side)	0.00	0.50	1.15	1.81	2.46	3.09	3.72	4.34	4.95	5.56	6.16	6.76	7.35			
Industrial-Mining	Emerging Technologies	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Mining	Other Program Measures	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Mining	Appliance Standards	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Mining	Building Standards	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Mining	Total	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Agricultural	Emerging Technologies	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Agricultural	Other Program Measures	Peak (MW, Customer Side)	0.00	0.13	0.27	0.40	0.54	0.68	0.81	0.95	1.09	1.23	1.38	1.52	1.66			
Agricultural	Appliance Standards	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Agricultural	Building Standards	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Agricultural	Total	Peak (MW, Customer Side)	0.00	0.13	0.27	0.40	0.54	0.68	0.81	0.95	1.09	1.23	1.38	1.52	1.66			
Steetlighting	Emerging Technologies	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Steetlighting	Other Program Measures	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Steetlighting	Appliance Standards	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Steetlighting	Building Standards	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Steetlighting	Total	Peak (MW, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
All Sectors	**Total**	**Peak (MW, Customer Side)**	**11.09**	**50.58**	**91.72**	**141.48**	**179.14**	**215.58**	**254.32**	**292.77**	**332.28**	**371.46**	**411.31**	**451.37**	**490.69**			
Residential	Emerging Technologies	Peak (MW, Includes Losses)	0.00	0.39	0.90	1.40	2.00	2.87	3.98	5.34	6.94	8.78	10.84	13.09	15.49			
Residential	Other Program Measures	Peak (MW, Includes Losses)	0.00	11.10	22.37	29.42	32.24	32.18	33.84	34.62	34.27	33.88	33.76	33.62	32.87			
Residential	Appliance Standards	Peak (MW, Includes Losses)	12.16	26.84	39.38	59.28	74.91	90.28	105.31	120.58	135.44	149.10	162.28	174.93	187.53			
Residential	Building Standards	Peak (MW, Includes Losses)	0.00	0.00	1.17	3.96	6.95	11.05	16.22	21.25	26.17	30.95	35.63	40.23	44.75			
Residential	Total	Peak (MW, Includes Losses)	12.16	38.33	63.83	94.06	116.10	136.37	159.35	181.79	202.83	222.72	242.51	261.87	280.64			
Commercial	Emerging Technologies	Peak (MW, Includes Losses)	0.00	1.17	2.77	3.64	4.73	6.09	7.16	8.34	10.71	13.43	16.42	19.74	23.39			
Commercial	Other Program Measures	Peak (MW, Includes Losses)	0.00	14.77	30.38	42.82	55.68	68.74	81.81	95.11	110.10	126.04	142.74	160.00	177.44			
Commercial	Appliance Standards	Peak (MW, Includes Losses)	0.00	0.48	1.88	11.50	15.44	19.21	22.74	26.16	29.19	31.34	33.34	35.17	36.29			
Commercial	Building Standards	Peak (MW, Includes Losses)	0.00	0.00	0.12	0.62	1.12	1.74	2.72	3.67	4.73	6.15	7.53	8.87	10.17			
Commercial	Total	Peak (MW, Includes Losses)	0.00	16.41	35.15	58.58	76.96	95.77	114.42	133.29	154.73	176.96	200.03	223.77	247.29			
Industrial-Manufacturing	Emerging Technologies	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Manufacturing	Other Program Measures	Peak (MW, Includes Losses)	0.00	0.54	1.08	1.61	2.13	2.64	3.15	3.65	4.15	4.64	5.13	5.61	6.09			
Industrial-Manufacturing	Appliance Standards	Peak (MW, Includes Losses)	0.00	0.00	0.18	0.38	0.56	0.75	0.93	1.10	1.28	1.45	1.62	1.79	1.96			
Industrial-Manufacturing	Building Standards	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Manufacturing	Total	Peak (MW, Includes Losses)	0.00	0.54	1.26	1.98	2.69	3.39	4.08	4.75	5.43	6.09	6.75	7.40	8.05			
Industrial-Mining	Emerging Technologies	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Mining	Other Program Measures	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Mining	Appliance Standards	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Mining	Building Standards	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Mining	Total	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Agricultural	Emerging Technologies	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Agricultural	Other Program Measures	Peak (MW, Includes Losses)	0.00	0.15	0.29	0.44	0.59	0.74	0.89	1.05	1.20	1.35	1.51	1.66	1.82			
Agricultural	Appliance Standards	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Agricultural	Building Standards	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Agricultural	Total	Peak (MW, Includes Losses)	0.00	0.15	0.29	0.44	0.59	0.74	0.89	1.05	1.20	1.35	1.51	1.66	1.82			
Steetlighting	Emerging Technologies	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Steetlighting	Other Program Measures	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Steetlighting	Appliance Standards	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Steetlighting	Building Standards	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Steetlighting	Total	Peak (MW, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
All Sectors	**Total**	**Peak (MW, Includes Losses)**	**12.16**	**55.43**	**100.53**	**155.06**	**196.34**	**236.27**	**278.74**	**320.87**	**364.18**	**407.12**	**450.80**	**494.70**	**537.80**			
Residential	Emerging Technologies	Energy (GWh, Customer Side)	0.00	3.09	7.07	10.72	15.12	21.56	29.84	40.11	52.25	66.14	81.69	98.79	117.03			
Residential	Other Program Measures	Energy (GWh, Customer Side)	15.08	86.09	160.30	197.58	209.17	197.02	202.84	211.08	218.10	223.58	227.82	232.71	231.86			
Residential	Appliance Standards	Energy (GWh, Customer Side)	11.91	28.47	43.47	97.04	134.07	169.37	202.35	237.13	269.36	293.41	314.00	330.66	347.10			
Residential	Building Standards	Energy (GWh, Customer Side)	0.00	0.00	0.95	3.23	5.66	8.98	13.18	17.26	21.26	25.14	28.94	32.67	36.34			
Residential	Total	Energy (GWh, Customer Side)	27.00	117.66	211.79	308.57	364.01	396.94	448.22	505.58	560.96	608.27	652.45	694.82	732.33			
Commercial	Emerging Technologies	Energy (GWh, Customer Side)	0.00	5.40	12.72	16.28	20.72	26.24	29.99	34.00	43.45	54.27	65.99	78.91	93.02			
Commercial	Other Program Measures	Energy (GWh, Customer Side)	0.09	73.25	148.83	204.94	260.89	318.62	376.10	428.93	486.86	546.87	608.00	668.93	720.59			
Commercial	Appliance Standards	Energy (GWh, Customer Side)	0.00	2.73	16.16	74.49	105.04	134.31	161.73	188.37	212.21	230.47	247.67	263.54	274.22			
Commercial	Building Standards	Energy (GWh, Customer Side)	0.00	0.00	0.67	3.50	6.28	9.77	15.32	20.65	26.60	34.58	42.32	49.84	57.19			
Commercial	Total	Energy (GWh, Customer Side)	0.09	81.38	178.38	299.20	392.92	488.94	583.14	671.96	769.12	866.19	963.97	1061.23	1145.02			
Industrial-Manufacturing	Emerging Technologies	Energy (GWh, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Manufacturing	Other Program Measures	Energy (GWh, Customer Side)	0.00	5.29	10.54	15.72	20.86	25.95	30.99	35.99	40.94	45.85	50.73	55.57	60.39			
Industrial-Manufacturing	Appliance Standards	Energy (GWh, Customer Side)	0.00	0.00	5.16	10.69	16.21	21.56	26.78	31.90	36.94	41.91	46.84	51.74	56.62			
Industrial-Manufacturing	Building Standards	Energy (GWh, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Manufacturing	Total	Energy (GWh, Customer Side)	0.00	5.30	15.70	26.41	37.07	47.51	57.77	67.89	77.88	87.77	97.57	107.31	117.01			
Industrial-Mining	Emerging Technologies	Energy (GWh, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Mining	Other Program Measures	Energy (GWh, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Mining	Appliance Standards	Energy (GWh, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Mining	Building Standards	Energy (GWh, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Mining	Total	Energy (GWh, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Agricultural	Emerging Technologies	Energy (GWh, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Agricultural	Other Program Measures	Energy (GWh, Customer Side)	0.00	2.10	4.22	6.36	8.51	10.68	12.86	15.05	17.26	19.48	21.71	23.95	26.21			
Agricultural	Appliance Standards	Energy (GWh, Customer Side)	0.00	0.00	0.00	0.00	0.19	0.35	0.49	0.60	0.68	0.73	0.77	0.79	0.81			
Agricultural	Building Standards	Energy (GWh, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Agricultural	Total	Energy (GWh, Customer Side)	0.00	2.10	4.22	6.36	8.70	11.03	13.35	15.65	17.94	20.21	22.48	24.75	27.02			
Steetlighting	Emerging Technologies	Energy (GWh, Customer Side)	0.00	1.71	3.45	5.13	6.80	8.52	10.01	11.26	12.39	13.40	14.39	15.38	16.30			
Steetlighting	Other Program Measures	Energy (GWh, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Steetlighting	Appliance Standards	Energy (GWh, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Steetlighting	Building Standards	Energy (GWh, Customer Side)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Steetlighting	Total	Energy (GWh, Customer Side)	0.00	1.71	3.45	5.13	6.80	8.52	10.01	11.26	12.39	13.40	14.39	15.38	16.30			
All Sectors	**Total**	**Energy (GWh, Customer Side)**	**27.08**	**208.15**	**413.54**	**645.67**	**809.51**	**952.93**	**1112.48**	**1272.34**	**1438.29**	**1595.84**	**1750.86**	**1903.49**	**2037.69**			
Note that GWH totals including losses are used to adjust baseline forecast net energy for load.																
Residential	Emerging Technologies	Energy (GWh, Includes Losses)	0.00	3.31	7.57	11.48	16.19	23.09	31.96	42.95	55.96	70.84	87.49	105.80	125.34			
Residential	Other Program Measures	Energy (GWh, Includes Losses)	16.15	92.21	171.68	211.61	224.02	211.01	217.24	226.07	233.58	239.46	243.99	249.23	248.33			
Residential	Appliance Standards	Energy (GWh, Includes Losses)	12.76	30.50	46.56	103.93	143.59	181.40	216.72	253.96	288.49	314.24	336.30	354.13	371.74			
Residential	Building Standards	Energy (GWh, Includes Losses)	0.00	0.00	1.02	3.46	6.06	9.62	14.12	18.49	22.77	26.93	30.99	34.99	38.92			
Residential	Total	Energy (GWh, Includes Losses)	28.91	126.01	226.83	330.48	389.86	425.12	480.04	541.48	600.79	651.46	698.77	744.15	784.33			
Commercial	Emerging Technologies	Energy (GWh, Includes Losses)	0.00	5.78	13.62	17.43	22.19	28.10	32.12	36.41	46.53	58.12	70.67	84.51	99.62			
Commercial	Other Program Measures	Energy (GWh, Includes Losses)	0.09	78.46	159.40	219.49	279.41	341.24	402.80	459.39	521.43	585.70	651.16	716.43	771.75			
Commercial	Appliance Standards	Energy (GWh, Includes Losses)	0.00	2.92	17.31	79.78	112.50	143.85	173.22	201.75	227.28	246.83	265.25	282.26	293.69			
Commercial	Building Standards	Energy (GWh, Includes Losses)	0.00	0.00	0.72	3.74	6.73	10.46	16.41	22.12	28.49	37.04	45.32	53.38	61.25			
Commercial	Total	Energy (GWh, Includes Losses)	0.09	87.16	191.04	320.44	420.82	523.65	624.54	719.67	823.73	927.69	1032.41	1136.58	1226.32			
Industrial-Manufacturing	Emerging Technologies	Energy (GWh, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
Industrial-Manufacturing	Other Program Measures	Energy (GWh, Includes Losses)	0.00	5.67	11.28	16.84	22.34	27.79	33.19	38.54	43.85	49.11	54.33	59.52	64.68			

Attachment J.2
SCGC-01 Revised Table 3
"SDGE Dec 16 AAEE"

Industrial-Manufacturing	Appliance Standards	Energy (GWh, Includes Losses)	0.00	0.00	5.53	11.45	17.36	23.09	28.68	34.16	39.56	44.89	50.17	55.41	60.64
Industrial-Manufacturing	Building Standards	Energy (GWh, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial-Manufacturing	Total	Energy (GWh, Includes Losses)	0.00	5.67	16.81	28.29	39.70	50.88	61.87	72.71	83.41	94.00	104.50	114.93	125.32
Industrial-Mining	Emerging Technologies	Energy (GWh, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial-Mining	Other Program Measures	Energy (GWh, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial-Mining	Appliance Standards	Energy (GWh, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial-Mining	Building Standards	Energy (GWh, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial-Mining	Total	Energy (GWh, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Agricultural	Emerging Technologies	Energy (GWh, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Agricultural	Other Program Measures	Energy (GWh, Includes Losses)	0.00	2.25	4.52	6.81	9.12	11.44	13.77	16.12	18.48	20.86	23.25	25.65	28.08
Agricultural	Appliance Standards	Energy (GWh, Includes Losses)	0.00	0.00	0.00	0.00	0.20	0.38	0.53	0.64	0.73	0.79	0.83	0.85	0.87
Agricultural	Building Standards	Energy (GWh, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Agricultural	Total	Energy (GWh, Includes Losses)	0.00	2.25	4.52	6.81	9.32	11.81	14.30	16.76	19.21	21.65	24.08	26.50	28.94
Steetlighting	Emerging Technologies	Energy (GWh, Includes Losses)	0.00	1.83	3.69	5.50	7.29	9.12	10.72	12.06	13.27	14.35	15.41	16.47	17.46
Steetlighting	Other Program Measures	Energy (GWh, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steetlighting	Appliance Standards	Energy (GWh, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steetlighting	Building Standards	Energy (GWh, Includes Losses)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steetlighting	Total	Energy (GWh, Includes Losses)	0.00	1.83	3.69	5.50	7.29	9.12	10.72	12.06	13.27	14.35	15.41	16.47	17.46
All Sectors	**Total**	**Energy (GWh, Includes Losses)**	**29.01**	**222.92**	**442.90**	**691.52**	**866.98**	**1020.59**	**1191.47**	**1362.68**	**1540.41**	**1709.14**	**1875.17**	**2038.64**	**2182.36**
Residential	Emerging Technologies	Natural Gas (MM Therms)	0.00	0.13	0.31	0.54	0.83	1.17	1.57	2.04	2.56	3.14	3.79	4.52	5.32
Residential	Other Program Measures	Natural Gas (MM Therms)	0.47	0.49	0.46	0.89	1.74	2.81	3.18	3.60	3.76	3.94	4.22	4.52	4.55
Residential	Appliance Standards	Natural Gas (MM Therms)	0.20	0.60	0.88	1.12	1.35	1.58	1.82	2.07	2.32	2.59	2.86	3.14	3.41
Residential	Building Standards	Natural Gas (MM Therms)	0.00	0.00	0.02	0.06	0.11	0.17	0.25	0.32	0.40	0.47	0.54	0.61	0.68
Residential	Total	Natural Gas (MM Therms)	0.68	1.21	1.67	2.61	4.02	5.73	6.83	8.03	9.03	10.14	11.42	12.79	13.95
Commercial	Emerging Technologies	Natural Gas (MM Therms)	0.00	0.00	-0.01	0.02	0.06	0.10	0.16	0.23	0.28	0.35	0.41	0.49	0.57
Commercial	Other Program Measures	Natural Gas (MM Therms)	0.01	0.55	1.13	1.97	2.84	3.71	4.59	5.47	6.33	7.18	8.03	8.87	9.67
Commercial	Appliance Standards	Natural Gas (MM Therms)	0.00	-0.01	-0.04	-0.11	-0.19	-0.26	-0.32	-0.39	-0.44	-0.46	-0.49	-0.51	-0.54
Commercial	Building Standards	Natural Gas (MM Therms)	0.00	0.00	0.01	0.03	0.05	0.07	0.11	0.15	0.20	0.26	0.32	0.37	0.43
Commercial	Total	Natural Gas (MM Therms)	0.01	0.54	1.09	1.91	2.76	3.62	4.54	5.47	6.37	7.32	8.27	9.22	10.13
Industrial-Manufacturing	Emerging Technologies	Natural Gas (MM Therms)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial-Manufacturing	Other Program Measures	Natural Gas (MM Therms)	0.00	0.14	0.27	0.41	0.55	0.68	0.82	0.96	1.10	1.24	1.38	1.51	1.65
Industrial-Manufacturing	Appliance Standards	Natural Gas (MM Therms)	0.00	0.00	-0.03	-0.05	-0.08	-0.10	-0.13	-0.15	-0.18	-0.20	-0.23	-0.25	-0.28
Industrial-Manufacturing	Building Standards	Natural Gas (MM Therms)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial-Manufacturing	Total	Natural Gas (MM Therms)	0.00	0.14	0.25	0.36	0.47	0.58	0.69	0.81	0.92	1.04	1.15	1.26	1.38
Industrial-Mining	Emerging Technologies	Natural Gas (MM Therms)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial-Mining	Other Program Measures	Natural Gas (MM Therms)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial-Mining	Appliance Standards	Natural Gas (MM Therms)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial-Mining	Building Standards	Natural Gas (MM Therms)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial-Mining	Total	Natural Gas (MM Therms)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Agricultural	Emerging Technologies	Natural Gas (MM Therms)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Agricultural	Other Program Measures	Natural Gas (MM Therms)	0.00	0.03	0.06	0.09	0.12	0.14	0.17	0.20	0.23	0.26	0.29	0.32	0.35
Agricultural	Appliance Standards	Natural Gas (MM Therms)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Agricultural	Building Standards	Natural Gas (MM Therms)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Agricultural	Total	Natural Gas (MM Therms)	0.00	0.03	0.06	0.09	0.12	0.14	0.17	0.20	0.23	0.26	0.29	0.32	0.35
All Sectors	**Total**	**Natural Gas (MM Therms)**	**0.68**	**1.92**	**3.06**	**4.97**	**7.37**	**10.07**	**12.23**	**14.50**	**16.56**	**18.76**	**21.13**	**23.59**	**25.81**
All Sectors 2016	**Total**	**Energy (GWh, Includes Losses)**	**29.01**	**222.92**	**442.90**	**691.52**	**866.98**	**1020.59**	**1191.47**	**1362.68**	**1540.41**	**1709.14**	**1875.17**	**2038.64**	**2182.36**
All Sectors 2015	**Total**	**Energy (GWh, Includes Losses)**	**29.01**	**222.92**	**442.90**	**691.52**	**866.98**	**1020.59**	**1191.47**	**1362.68**	**1540.41**	**1709.14**	**1875.17**	**2038.64**	
All Sectors 2016	**Total**	**Natural Gas (MM Therms)**	**0.68**	**1.92**	**3.06**	**4.97**	**7.37**	**10.07**	**12.23**	**14.50**	**16.56**	**18.76**	**21.13**	**23.59**	**25.81**
All Sectors 2015	**Total**	**Natural Gas (MM Therms)**	**0.68**	**1.92**	**3.06**	**4.97**	**7.37**	**10.07**	**12.23**	**14.50**	**16.56**	**18.76**	**21.13**	**23.59**	

Relative to 2015 savings	Natural Gas (MDth)		123	238	428	668	939	1,155	1,382	1,587	1,807	2,045	2,291	2,512			
	Natural Gas MMcf		120	232	419	653	918	1,129	1,351	1,552	1,767	1,999	2,239	2,456	2,692	2,951	3,235
Relative to 2015 savings	Energy (GWh, Includes losses)		194	414	663	838	992	1,162	1,334	1,511	1,680	1,846	2,010	2,153	2,311	2,481	2,663
	Equv Natural Gas MMcf		873	1,814	2,824	3,471	3,988	4,558	5,095	5,621	6,079	6,494	6,861	7,130	7,415	7,702	7,993
	RPS Percentage		25%	27%	29%	31%	33.0%	34.7%	36.4%	38.0%	39.7%	41.4%	43.1%	44.8%	46.6%	48.3%	50%
					from p118 of 2016 CGR growth of SDG&E non-EG AAEE												
	growth of cumulative nat gas AAEE		0.096197		1.248354	0.122609	1.12401										
	growth of cumulative elec AAEE		0.073364														

SB350 Effect	2016	2017	2018	2019	2020	2025	2030	2035
Gas Energy Efficiency SavingsMMcf/d	0	1	1	2	3	5	9	14
Gas Savings from Electricity Savings MMcf/d	2	5	8	10	11	18	25	36
Total MMcf/d	3	6	9	11	13	23	34	50

Combined Gas & Electric	2016	2017	2018	2019	2020	2025	2030	2035
Energy Efficiency Savings MMcf/d	(1)	(1)	(1)	(1)	(1)	(2)	0	(0)

	2016	2017	2018	2019	2020	2025	2030	2035
Electric Energy Efficiency Savings MMcf/d from AAEE Diff	-	-	-	-	-	-	-	#DIV/0!

Apportion Gas AAEE between core & noncore	2016	2017	2018	2019	2020	2025	2030	2035	
Gas Energy Efficiency Savings MMcf/d from AAEE Diff	(1)	(1)	(1)	(1)	(1)	(2)	0	(0)	
Gas Energy Efficiency Savings MMcf/d from SB 350	0	1	1	2	3	5	9	14	
	(0)	(0)	0	1	1	4	9	14	
Core 81%	(0.16)	(0.06)	0.21	0.61	1.21	2.87	7.19	11.09	0.81
Noncore	(0.04)	(0.01)	0.05	0.14	0.28	0.67	1.69	2.60	

Table 1

Operating Year a/	Core	Noncore C&I	EG	Total
2016/17	366	60	152	578
2017/18	374	61	153	588
2018/19	374	61	154	589
2019/20	374	62	154	589
2020/21	374	62	154	590
2021/22	373	62	146	581
2022/23	372	62	138	572
2023/24	371	62	130	563
2024/25	370	62	123	556
2025/26	370	62	116	548
2030/31	374	62	103	539
2035/36	381	61	103	546

[a] An *Operating Year is April thru March.*

Adjusted Table 1 including Line 1600 & 1026 effects

Operating Year a/	Core	Noncore C&I	EG	Total
2016/17	365	60	137	562
2017/18	373	61	134	568
2018/19	373	61	132	566
2019/20	372	62	132	566
2020/21	372	62	131	565
2021/22	370	62	#VALUE!	#VALUE!
2022/23	369	62	#VALUE!	#VALUE!
2023/24	368	61	#VALUE!	#VALUE!
2024/25	366	61	#VALUE!	#VALUE!
2025/26	366	61	#VALUE!	#VALUE!
2030/31	366	60	72	498
2035/36	369	58	#DIV/0!	#DIV/0!

note L1026 carries 1 MMcf/d core & L1600 carries 5 MMcf/d EG

Adjusted Table 1 with minimum EG

Operating Year a/	Core	Noncore C&I	Minimum EG
2016/17	365	60	96
2017/18	373	61	96
2018/19	373	61	96
2019/20	372	62	96
2020/21	372	62	96

Attachment J.2
SCGC-01 Revised Table 3
"SDGE AAEE Diff"

Difference Between SDG&E AAEE used in 2016 GRC and CEC Mid-Range AAEE used in 2016 CEDU (note 2015 IEPR uses same AAEE)

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Relative to 2015 savings from 2016 CEDU	Natural Gas (MDth)	123	238	428	668	939	1,155	1,382	1,587	1,807	2,045	2,291	2,512			
note AAEE doesn't change from 2015 IEPR	Natural Gas MMcf	120	232	419	653	918	1,129	1,351	1,552	1,767	1,999	2,239	2,456	2,692	2,951	3,235
Relative to 2015 savings	Energy (GWh, Includes lo	193.92	413.89	662.51	837.98	991.58	1162.46	1333.67	1511.40	1680.14	1846.17	2009.64	2153.36	2311.34	2480.91	2662.92
	Equv Natural Gas MMcf	873.07	1813.76	2823.72	3470.95	3988.16	4558.16	5094.91	5621.37	6079.41	6493.88	6861.49	7129.97	7414.53	7702.46	7992.74
	Percent RPS	25%	27%	29%	31%	33%	35%	36%	38%	40%	41%	43%	45%	47%	48%	50%
	Percentage Nat Gas	75%	73%	71%	69%	67%	65%	64%	62%	60%	59%	57%	55%	53%	52%	50%
	Gas Savings MMcfd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Combined MMcf	120	232	419	653	918	1,129	1,351	1,552	1,767	1,999	2,239	2,456	2,692	2,951	3,235

From SDG&E Response to SCGC-12, Q.12.7.1.	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Combined natural gas savings	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf	mmcf
	313	492	744	1,033	1,290	1,587	1,916	2,252	2,601	2,704	2,738	2,908	3,005	3,065	3,157

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Difference CEC Mid-Range AAEE vs SDG&E		-193	-260	-326	-380	-372	-458	-566	-700	-834	-705	-499	-452	-313	-114	78
		(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(1)	(1)	(1)	(0)	0
Estimated separation between gas and elec	gas	-193	-260	-326	-380	-372	-458	-566	-700	-834	-705	-499	-452	-313	-114	78
	elec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	gas	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(1)	(1)	(1)	(0)	0
	elec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Attachment K

Sierra Club Responses to Utilities' Data Requests

Attachment K-1

Sierra Club Response to Utilities' DR 03, Q2 and Q4

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In The Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for a Certificate of Public Convenience and Necessity for the Pipeline Safety & Reliability Project	Application 15-09-013

RESPONSE TO THIRD SET OF DATA REQUESTS PROPOUNDED BY SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) AND SOUTHERN CALIFORNIA GAS COMPANY (U904G) UPON SIERRA CLUB

MATTHEW VESPA
ALISON SEEL
Sierra Club
2101 Webster Street, Suite 1300
Oakland, CA 94612
Telephone: (415) 977-5753
Email: matt.vespa@sierraclub.org
alison.seel@sierraclub.org

Attorneys for Sierra Club

May 10, 2017

DATA REQUEST NO. 1

Sierra Club-01 at page 2, lines 11-14 states: "An investment at the level of the Proposed Project is sure to lead to substantial gas rate increases that serve little legitimate purpose being borne by a shrinking customer base – the classic case of stranded cost. The State has been there before and does not need to go there again."

a. Please explain what is meant by "the classic case of stranded cost."
b. Please identify each instance in which the "State has been there before."

RESPONSE NO. 1:

a) Stranded costs arise when the utility makes a long-term investment on behalf of its customers and cost recovery of that investment is authorized in rates. Then, at some point thereafter, either the customers leave utility bundled service, or the investment itself is no longer used and useful to the remaining customers. In either case, these costs are termed "stranded."

b) In the wake of the energy crisis, a significant number of gas-fired power plants were built in California. Now, approximately 15 years later, independent power producers have announced plans to retire several of these plants well before the end of their 30-40 year lifespan. If the utilities had built these plants, their costs would now be "stranded." The primary driver of these retirements is the growth of utility and behind-the-meter renewable energy. When built in the early 2000s, it would have been difficult to anticipate the rapid transformation of California's energy system, its increasing renewable mandates, the rapid price declines in the cost of renewable energy, or what would become the State's aggressive decarbonization mandates, which was first established through Executive Order in 2005. Today, however, we have established long-term decarbonization goals and therefore a better ability to predict whether new investments in fossil-fuel infrastructure, like Proposed Line 3602 would be needed through the project lifetime.

DATA REQUEST NO. 2

Sierra Club-01 at page 2, lines 15-20 states: "Following the closure of the San Onofre Nuclear Generating Station (SONGS) in 2012, the problem of a mismatch between the capabilities of the gas and electric infrastructure was indeed quite large as demonstrated by Applicants. However, Applicants fail to account for the fact that the problem has already been nearly resolved and potentially totally resolved by the investment of billions of dollars in electric infrastructure following that incident."

a. Please identify all the electric infrastructure investments that "nearly resolved and potentially totally resolved" the cited incident.
b. Please state whether such electric infrastructure investments would ensure reliable electric service to SDG&E customers in the event of a Line 3010 outage. Please state all facts that support your response, produce all documents that support your response, and identify the

person responsible for this response.

c. Please state whether such electric infrastructure investments would ensure reliable electric service to SDG&E customers in the event of an outage of the Moreno Compressor Station. Please state all facts that support your response, produce all documents that support your response, and identify the person responsible for this response.

RESPONSE NO. 2:

a) The following list of transmission and generation investments comes from the CAISO *2022 Local Capacity Technical Analysis* (May 3, 2017), p. 64, available at https://www.caiso.com/Documents/Final2022Long-TermLocalCapacityTechnicalReport.pdf (accessed May 9, 2017). These projects have been authorized and funded and are in planning or construction stages. These projects are not yet in service but all have an in-service date within the next five years.

1. Second Encina 230/138 bank #61
2. Reconductor of Mission-Mesa Heights and Mesa Heights loop- in 69 kV project
3. Reconductor of Kearny-Mission 69 kV line
4. T600 Loop-in to Mesa Hights 69 kV
5. TL6906 Mesa Rim reconfiguration
6. Salt Creek 69 kV substation
7. Vine 69 kV substation
8. Ocean Ranch 69 kV substation
9. Second Poway to Pomerado line
10. TL632 Granite loop-in and TL6914 reconfiguration
11. Reconductor of Stuart Tap-Las Pulgas 69 kV line (TL690E)
12. Reconductor of Japanes Mesa–Basilone–Talega Tap 69 kV lines
13. Second San Marcos – Escondido 69kV line
14. Upgrade Bernardo - Rancho Carmel 69kV line
15. Second Poway-Pomerado 69 kV line
16 Bay Boulevard 230 kV substation
17. Imperial Valley phase shifting transformers
18. Sycamore - Penasquitos 230kV Line
19. Artesian 230 kV expansion with 69kV upgrade
20. Second Miguel – Bay Boulevard 230 kV line
21. South Orange County Reliability Enhancement
22. Miguel synchronous condensers (2x225 Mvar)
23. San Luis Rey synchronous condensers (2x225 Mvar)
24. San Onofre synchronous condenser (1x240 Mvar)
25. Suncrest SVC project
26. New capacitors at Pendlenton and Basilone 69 kV substations
27. Storage projects at Escondido(3x10 MW) and El Cajon (7.5 MW)
28. Carlsbad Energy Center (500 MW)

None of these projects were modeled in Table 2 of Exhibit SDGE-4-R.

Thirteen additional projects may also be missing from the power flow used to construct Table 2. These thirteen projects were listed as some of the 25 "new projects" in the CAISO 2019 Long Term Local Capacity Technical Report (*See* Appendix E, Board Approved 2014-2015 Transmission Plan, pp.97-98 (February 2, 2015), available at https://www.caiso.com/Documents/AppendixEBoardApproved2014-2015TransmissionPlan.pdf (accessed May 9, 2017). However, these thirteen projects are not listed in the 2022 version of the report, cited above. It is standard CAISO practice to only list projects that are authorized but not currently in service on the "new project" list, and also to record if projects on previous "new project" lists were subsequently cancelled or redefined, rather than placed in service. No such record of changes to the 2015 list appears in either the 2015 or 2016 versions of the Transmission Plan. Therefore, it can be assumed that these 13 projects were placed in service between Feb 2015 and May 2017. It is unclear whether any of these thirteen projects that probably entered service in the interim between the two reports were modeled in the "mid 2015" power flow runs in Table 2 of Exhibit SDGE-4-R. If not, some or all of these 13 projects would further increase the San Diego Import Limit.

b) It is not possible to individually quantify the impact of each of these 41 reinforcement projects on "ensuring reliable electric service to SDG&E customers in the event of a Line 3010 outage." However, as explained in Sierra Club's testimony, these investments act to collectively raise the San Diego Import Limit above that depicted in Table 2 of Exhibit SDGE-4-R and thus reduce the amount of local gas fired generation required in the San Diego region during a hypothetical Line 3010 outage.

c) Similar to our answer to question 2(b), above, it is not possible to individually assess the impact of each of these 41 reinforcement projects on "ensuring reliable electric service to SDG&E customers in the event of an outage of the Moreno Compressor Station." However, as explained in Sierra Club's testimony, these investments raise the San Diego Import Limit above that depicted in Table 2 of Exhibit SDGE-4-R and thus reduce the amount of local gas fired generation required in the San Diego region during a hypothetical outage of the Moreno Compressor Station.

This response was prepared by Jim Caldwell.

DATA REQUEST NO. 3:

Sierra Club-01 at page 8, lines 27-31 states: "Applicants estimate the cost of Proposed Line 3602 would exceed $600 million. [footnote omitted] Even if additional pipeline capacity might be useful to integrate renewables under certain scenarios, investing in electric infrastructure instead would meet this need at much lower cost while also moving California closer to a decarbonized future."

a. Please identify each electric infrastructure investment that Sierra Club is referring to as "useful to integrate renewables under certain scenarios."

b. For each electric infrastructure investment identified in response to subsection (a), identify the sponsor for such investment.

c. For each electric infrastructure investment identified in response to subsection (a), state the estimated cost and explain the basis for such cost estimate.

d. Produce all workpapers and documents supporting Sierra Club's responses to subsections (a)-(c).

RESPONSE NO. 3:

Sierra Club does not understand this question and believes the quoted sentence from our testimony has been misunderstood. In the sentence, the clause "useful to integrate renewables under certain scenarios" is referring to "additional pipeline capacity" and not to the term "electric infrastructure."

DATA REQUEST NO. 4

Sierra Club-01 at page 5, line 15 to page 6, line 6 states: "In addition, the cost of Line 3602 would be recoverable through rates through at least 2063, [footnote omitted] well after electric generation should be almost entirely carbon free and natural gas end uses, such as residential heating, should have switched from natural gas to electric sources. Viewed in the context of California's decarbonization trajectory, Proposed Line 3602 is the type of dead-end infrastructure investment that would result in significant stranded costs and that should be avoided." With respect to "natural gas end uses," please answer the following questions:

a. With respect to residential gas heating:
   - i. When does Sierra Club contend that the switch from gas residential heating to nongas residential heating in existing homes will be completed in SDG&E's service territory?
   - ii. Does Sierra Club contend that the switch from gas residential heating to non-gas residential heating in existing homes in SDG&E's service territory will be required by law or regulation? If no, please state why you believe that homeowners will switch from gas heating to non-gas heating in existing homes.
   - iii. Please state the estimated cost of switching from gas residential heating to non-gas residential heating in all of the existing homes in SDG&E's service territory.
   - iv. Please state who Sierra Club expects will pay the cost of switching from gas residential heating to non-gas residential heating in existing homes in SDG&E's service territory?
   - v. Please state all facts that support your responses, produce all documents that support your responses, and identify the person responsible for your responses.

b. With respect to residential gas cooking and clothes drying:
   - i. When does Sierra Club contend that the switch from residential gas cooking and clothes drying to non-gas cooking and clothes drying in existing homes will be completed in SDG&E's service territory?
   - ii. Does Sierra Club contend that the switch from residential gas cooking and clothes drying to non-gas cooking and clothes drying in existing homes in SDG&E's service territory will be required by law or regulation? If no, please state why you believe that homeowners will switch from residential gas cooking and clothes drying to non-gas cooking and clothes drying in existing homes.

iii. Please state the estimated cost of switching from residential gas cooking and clothes drying to non-gas cooking and clothes drying in all of the existing homes in SDG&E's service territory.

iv. Please state who Sierra Club expects will pay the cost of switching from residential gas cooking and clothes drying to non-gas cooking and clothes drying in existing homes in SDG&E's service territory?

v. Please state all facts that support your responses, produce all documents that support your responses, and identify the person responsible for your responses.

c. With respect to gas heating in non-residential buildings:

i. When does Sierra Club contend that the switch from gas heating to non-gas heating in existing non-residential buildings will be completed in SDG&E's service territory?

ii. Does Sierra Club contend that the switch from gas heating to non-gas heating in existing non-residential buildings in SDG&E's service territory will be required by law or regulation? If no, please state why you believe that building owners or tenants will switch from gas heating to non-gas heating in existing buildings.

iii. Please state the estimated cost of switching from gas heating to non-gas heating in all of the existing non-residential buildings in SDG&E's service territory.

iv. Please state who Sierra Club expects will pay the cost of switching from gas heating to non-gas heating in existing non-residential buildings in SDG&E's service territory?

v. Please state all facts that support your responses, produce all documents that support your responses, and identify the person responsible for your responses.

d. With respect to gas cooking in existing non-residential buildings:

i. When does Sierra Club contend that the switch from gas cooking to non-gas cooking in existing non-residential buildings will be completed in SDG&E's service territory?

ii. Does Sierra Club contend that the switch from gas cooking to non-gas cooking in existing non-residential buildings in SDG&E's service territory will be required by law or regulation? If no, please state why you believe that building owners or tenants will switch from gas cooking to non-gas cooking in existing buildings.

iii. Please state the estimated cost of switching from gas cooking to non-gas cooking in all of the existing non-residential buildings in SDG&E's service territory.

iv. Please state who Sierra Club expects will pay the cost of switching from gas cooking to non-gas cooking in existing non-residential buildings in SDG&E's service territory?

v. Please state all facts that support your responses, produce all documents that support your responses, and identify the person responsible for your responses.

e. With respect to gas-fired equipment in existing manufacturing facilities:

i. When does Sierra Club contend that the switch from gas-fired equipment in existing manufacturing facilities to non-gas-fired equipment will be completed in SDG&E's service territory?

ii. Does Sierra Club contend that the switch from gas-fired equipment in existing manufacturing facilities to non-gas-fired equipment in SDG&E's service territory will be required by law or regulation? If no, please state why you believe that the manufacturers will switch from gas-fired equipment in existing manufacturing facilities to non-gas-fired equipment.

iii. Please state the estimated cost of switching from gas-fired equipment in existing manufacturing facilities to non-gas-fired equipment in SDG&E's service territory.

iv. Please state who Sierra Club expects will pay the cost of switching from gas-fired equipment in existing manufacturing facilities to non-gas-fired equipment in SDG&E's service territory?

v. Please state all facts that support your responses, produce all documents that support your responses, and identify the person responsible for your responses.

RESPONSE NO. 4:

(a)-(e) i) Electrification of natural gas end uses of all types is expected to occur over the lifetime of the Proposed Project. All studies Sierra Club is aware of that model the changes necessary to meet California's long term decarbonization goals consistently find that widespread electrification of natural gas end uses must occur. For example, a detailed analysis performed for the California Energy Commission by Lawrence Berkeley National Lab found that meeting California's goal of reducing carbon emissions by 80% below 1990 levels by 2050 requires full electrification of all space and water heating in residential and commercial buildings. M. Wei et al., *Scenarios For Meeting California's 2050 Climate Goals*. California Energy Commission (Sept. 2013), p. 80. Available at http://www.energy.ca.gov/2014publications/CEC-500-2014-108/CEC-500-2014-108.pdf (accessed May 9, 2017). Sierra Club's testimony also attached the Deep Decarbonization Pathways study, which similarly finds that electrification of natural gas end uses is essential to achieve the international goal of reducing greenhouse gas emissions to levels consistent with limiting the anthropogenic increase in global mean surface temperature to less than 2 degrees Celsius.

ii) Sierra Club objects to this question as calling for speculation, in that it asks Sierra Club to speculate on future actions the state government and state agencies may take to facilitate and fund electrification efforts, which are not known at this time.

Without waiving this objection, Sierra Club provides the following answer: Building electrification is in its early stages and will accelerate in the coming years. Sierra Club expects a variety of methods and policies will be used to promote electrification. One example that the Sierra Club is aware of is the new CEC effort to implement S.B. 350 (CEC Docket #17-IEPR-06). One means of achieving S.B. 350's requirement to double savings from electricity and natural gas by 2030 is through programs "that save energy in final end uses by using cleaner fuels," such as building electrification. *See* California Energy Commission Staff, *Framework for Establishing the Senate Bill 350 Energy Efficiency Savings Doubling Targets* (Jan. 18, 2017) (citing Cal. Pub. Res. Code section 25310(d)). Available at http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-06/TN215437_20170118T160001_Framework_for_Establishing_the_Senate_Bill_350_Energy_Efficienc.pdf (accessed May 8, 2017). Additionally, parties are advocating for revisions to the 2019 building code to facilitate electrification. *See,* *e.g.,* NRDC Comments on CEC's Staff Workshop on the 2019 Zero Net Energy Residential Standards in CEC Docket #17-BTSD- 01 (May 5, 2017), available at http://docketpublic.energy.ca.gov/PublicDocuments/17-BSTD-01/TN217458_20170505T143733_Alexander_Hillbrand__NRDC_Comments_NRDC_Comments_on_CEC%E2%80%99s_Staff.pdf (accessed May 9, 2017). All-electric home pilot projects may be conducted in Phase II of R. 15-03-010, the proceeding to implement Assembly Bill 2672.

iii) Sierra Club objects to this question as overly burdensome and expensive per Rule 10.1 of the Commission's Rules of Practice and Procedure. The request does not seek data in the Sierra Club's possession, but requests Sierra Club perform an ambitious research and modeling project requiring a great deal of data that Sierra Club does not possess, notably including the number of "all of the existing homes in SDG&E's service territory."

Without waiving this objection, Sierra Club provides the following response: Electrification of natural gas end-uses is a rapidly evolving and growing field. The cost-benefit analysis of a switch to electric appliances depends on many factors and many dynamic costs, including gas prices, the customer's electric tariff schedule, the necessity and cost of home wiring upgrades, and appliance costs.

iv) Sierra Club objects to this question as calling for speculation, in that it asks Sierra Club to speculate on what future actions the state and state agencies may take to encourage and fund electrification efforts.

Without waiving this objection, Sierra Club provides the following answer: Similar to how the state supported transportation electrification with rebates and ratepayer-funded programs, building electrification may be funded in a variety of ways, including but not limited to state technology rebates, utility-sponsored energy efficiency programs, or by investments of property owners themselves.

v) This response was prepared by Alison Seel.

DATA REQUEST NO. 5:

Sierra Club-01 at page 8, lines 1-19 cites the California Energy Commission (CEC) 2016 Integrated Energy Policy Report (IEPR) Update: "As California moves away from fossil fuels to reduce greenhouse gas emissions, it will need more resources that can be depended on to quickly and cost-effectively ramp up or down to help maintain the reliability of the electricity system. Flexibility is necessary to compensate for hourly changes in variable renewable generation and energy demand, as well as outages for power plant maintenance and seasonal variations in hydropower generation. Natural gas-fired power plants offer the most flexibility for quickly, reliably, and cost-effectively ramping up or down to balance supply and demand. California relies on the ramping capabilities of natural gas even as it is moving away from using it—in the summer of 2016 natural gas use was down 20 percent in California compared to the previous year due to better hydroelectric conditions and more renewable energy coming online. The state

Attachment K-2

Sierra Club Response to Utilities’ DR 04, Q6

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In The Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for a Certificate of Public Convenience and Necessity for the Pipeline Safety & Reliability Project	Application 15-09-013

RESPONSE TO FOURTH SET OF DATA REQUESTS PROPOUNDED BY SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) AND SOUTHERN CALIFORNIA GAS COMPANY (U904G) UPON SIERRA CLUB

MATTHEW VESPA
ALISON SEEL
Sierra Club
2101 Webster Street, Suite 1300
Oakland, CA 94612
Telephone: (415) 977-5753
Email: matt.vespa@sierraclub.org
alison.seel@sierraclub.org

Attorneys for Sierra Club

May 15, 2017

RESPONSE NO. 5:

As stated in its testimony, Sierra Club could find no citation in the public record for the SDIT when all planned and authorized transmission reinforcements are in service. However, the "Heavy RPS Output" Sensitivity Scenario Study in CAISO's 2016-2017 Transmission Plan lists the SDIT Flow Assumption as 3527 MW in the 2021 Summer Peak Power Flow Study. CAISO Board Approved 2016-2017 Transmission Plan *supra*,at Table 2.9-5, p. 144). The SDIT Flow must be less than or equal to the SDIT "limit for planning purposes."

DATA REQUEST NO. 6

Sierra Club at page 26, footnote 71, states: "This calculation uses the minimum possible value of 3,527 MW for the N-1 compliant SDIT, the projected 2026 peak load for planning purposes of 4,580 MW, and adds in the additional nongas generation already authorized for procurement of 225 MW." With respect to this calculation:

a. Please identify the 225 MW of "additional nongas generation" by sponsor, location, fuel, current status and expected in-service date.

RESPONSE NO. 6

The 224.6 MW of preferred resources and energy storage is identified in Table 2.9-2 of the Board Approved CAISO 2016-2017 Transmission Plan, supra, at p. 142. This table is provided in the answer to Question 4(a), above. The table breaks down these 224.6 MW of new resources by in-service date, MW, and resource type. It is Sierra Club's understanding that the resources identified by CAISO in Table 2.9-2 have been or will be procured by SDG&E through its various procurement mechanisms. Specifics on sponsor location, fuel, current status and expected in-service data should be in Applicant's possession or under Applicant's control for future procurements. Given the Commission's prohibition of fossil-reliant resources in demand resource programs, Sierra Club does not believe any of these resource rely on natural gas for fuel.

DATA REQUEST NO. 7

Sierra Club-1 at page 27, lines 7-12, states: "Alternately, the planning shortfall, if any, could be met with minor additional reinforcements of the electric transmission system. The most obvious of these would be to raise the SDIT even further by "reconductoring" to increase the capacity of the S Line that would cost roughly $35 M with those costs shared by all statewide electric customers of the CAISO plus customers of the Imperial Irrigation District." With respect to this testimony:

a. Who does Sierra Club contend would be the sponsor of such an S-Line project?
b. Which ratepayers would pay the cost of upgrading the IID S-Line?
c. If Sierra Club contends that the cost would be split between IID and CAISO ratepayers, please provide documentation regarding the split cost allocation mechanism that will assist this process.
d. Please produce all workpapers and documents supporting the $35M cost estimate, including

a breakdown of the costs.

e. Which regulatory agencies would need to approve such a project?

f. What are the consequences to the CAISO and IID electric transmission systems of the proposed project? Please produce Power System Studies and technical assumptions regarding implementation of the proposed S-Line project.

g. After the upgrade of the S-line, what is the next contingency/limitation?

RESPONSE NO. 7

a) San Diego Gas and Electric Company itself has recommended reinforcement of the IID S Line as a cost effective way to increase the SDIT and thus reduce the requirement for in basin gas generation for electric system reliability. For example, it made the following suggestion to the CAISO in the recent 2018 Local Capacity Technical Analysis proceeding:

> "Work with the IID to Find Mutually Beneficial Ways to Mitigate S-Line Loading
> It is in all parties' interests to explore different ways of mitigating contingency-based flows on the S-line since the S-line is the binding constraint for the critical contingency condition which establishes LCRs in the Greater Imperial Valley-San Diego area and in the LA Basin area. Several concepts have emerged which warrant further discussion. For example, a Remedial Action Scheme (RAS) that cross-trips the S-line for the outage of the 500 kV North Gila-Imperial Valley line would eliminate the S-line as a limiting element. Installing a reactive "smart wires" device on the S-line not only would help to reduce S-line flows, but also can be used to push more power through the S-line, if the line is not overloaded." *SDG&E's Comments on the CAISO's March 9, 2017 Stakeholder Meeting Presenting Local Capacity Requirement (LCR) Results for the 2018 Resource Adequacy (RA) Compliance Year* (March 30, 2017), p. 4 (available at http://www.caiso.com/Documents/SDG_EComments_2018_2022DraftLocalCapacityRequirementsResults.pdf).

b) As a "reliability upgrade," the FERC-regulated CAISO tariff specifies that the cost of this upgrade would be added to the Transmission Access Charge paid for by all users of the CAISO grid including SDG&E electric load bundled customers. The CPUC authorizes cost recovery of this charge from retail customers in the utility General Rate Case. To the extent that the upgrade also benefits IID customers, FERC precedent requires cost sharing.

c) As a template for how negotiations might proceed with IID on cost sharing, Sierra Club notes the recent successful negotiation between CAISO and LADWP to conduct analogous mutually beneficial upgrades to each the two systems on the Lugo-Victorville 500 kV line north and west of the S Line. *See* CASISO Board-Approved 2016-2017 Transmission Plan, hyperlinked *supra*, at p. 128.

d) Sierra Club's estimate of the cost to reconductor the S Line is nothing more than a generic "planning assumption" of $1M/mile and does not represent an engineering analysis of the specific project. Either of the two suggestions above made by SDG&E would cost roughly 10% of reconductoring. Sierra Club has no definitive opinion on which of these three

Attachment L

Effect of Updating Electricity Forecast

Attachment L
Effect of Updating Electricity Forecast

Electricity Demand (GWh) used in 2016 CGR
Form 1.5a - Statewide
Net Energy for Load by Agency and Balancing Authority (GWh)
California Energy Demand Update Forecast, 2015 - 2026, Mid Demand Baseline Case, Mid AAEE Savings

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Statewide	286,694	285,119	283,849	281,846	280,584	279,846	279,322	279,653	279,465	279,016	278,654	277,974	277,396	276,822	276,252	275,685	275,123	274,565	274,011	273,461	272,915

Electricity Demand (GWh) from 2016 Update
Form 1.5a - Statewide
Net Energy for Load by Agency and Balancing Authority (GWh)
California Energy Demand Update Forecast, 2015 - 2027, Mid Demand Baseline Case, Mid AAEE Savings

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Statewide	284,270	282,393	279,187	276,864	276,563	276,255	276,103	277,160	277,716	277,817	278,004	277,834	277,795	277,287	276,784	276,286	275,793	275,306	274,823	274,346	273,873

Difference in (GWh): 2016 Update - 2016 CGR

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Statewide	(2,424)	(2,726)	(4,662)	(4,982)	(4,020)	(3,591)	(3,219)	(2,493)	(1,750)	(1,199)	(650)	(140)	399	465	533	601	670	741	812	885	959

Difference in (%)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Statewide	-1%	-1%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Change in Cold Day Gas Demand Forecast, EG Component

	2016	2017	2018	2019	2020	2025	2030	2035
Electricity Demand Reduction (%)	-1%	-2%	-2%	-1%	-1%	0%	0%	0%
EG Gas Demand Forecast (MMcf/d)	152	153	154	154	154	116	103	103
EG Gas Demand Reduction (MMcf/d)	-1	-3	-3	-2	-2	0	0	0

Attachment M

Comparison CED 2013 Revised AAEE vs CED 2015 AAEE

Attachment M

Comparison CED 2013 Revised AAEE vs CED 2015 AAEE

CEC's Forecasted Cumulative AAEE Savings (MMcf, 1.023 MDth/MMcf)	**2016***	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
CED 2013 Revised Mid AAEE**	313	492	744	1033	1290	1587	1916	2252	2601	2704	2738	2908	3005	3065	3157	3209	3228	3242	3242	3242
CED 2015 Mid AAEE	313	299	485	720	985	1196	1417	1618	1834	2066	2306									

Calculated Incremental AAEE Savings Based On CEC Forecast (MMcf, 1.023 MDth/MMcf)	**2016***	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
CED 2013 Revised Mid AAEE**	[redacted]																			
CED 2015 Mid AAEE	313	-13.74	186.03	234.62	264.78	211.15	221.54	201.00	215.15	232.14	240.27	240.27	240.27	240.27	240.27	240.27	240.27	240.27	240.27	240.27

Calculated Cumulative AAEE Savings Based On CEC Forecasts (MMcf, 1.023 MDth/MMcf)	**2016***	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
CED 2013 Revised Mid AAEE**	313	492	744	1033	1290	1587	1916	2252	2601	2704	2738	2908	3005	3065	3157	3209	3228	3242	3242	3242
CED 2015 Mid AAEE	313	299	485	720	985	1196	1417	1618	1834	2066	1993	2247	2301	2307	2282	2311	2330	2369	2395	2403
Difference	**0**	**-193**	**-259**	**-313**	**-305**	**-391**	**-499**	**-633**	**-767**	**-638**	**-745**	**-661**	**-704**	**-758**	**-875**	**-897**	**-898**	**-872**	**-847**	**-839**

* 3.2 million therms AAEE savings for year 2016 from Decision D.15-10-028, p.9, Table3. Please see:
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M155/K511/155511942.pdf

** SDG&E AAEE savings were cumulated from the CED 2013 Final Forecast, Mid Savings Scenario, Revised April 2014 and were provided in an attachment to SDG&E's response to SCGC data request 12, question 12.7.1.

Attachment N

NERC TPL-001-4

A. Introduction

1. **Title: Transmission System Planning Performance Requirements**

2. **Number: TPL-001-4**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

- a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
- b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   - a. Loss of a tower line with three or more circuits.[11]
   - b. Loss of all Transmission lines on a common Right-of-Way[11].
   - c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   - d. Loss of all generating units at a generating station.
   - e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   - a. Loss of two generating stations resulting from conditions such as:
     - i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
     - ii. Loss of the use of a large body of water as the cooling source for generation.
     - iii. Wildfires.
     - iv. Severe weather, e.g., hurricanes, tornadoes, etc.
     - v. A successful cyber attack.
     - vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   - b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   - a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   - b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   - c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   - d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   - e. 3Ø internal breaker fault.
   - f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. 2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. 4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. 5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point. 8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker. 9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. 10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. 11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less. 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction. 13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in	

		Requirement 1 from Medium to High.	

Attachment O

Peak RC's SOL Methodology for the Operations Horizon

SYSTEM OPERATING LIMITS METHODOLOGY FOR THE OPERATIONS HORIZON

Rev. 8.1

By

Peak Reliability

February 24, 2017

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A. Conventions

When a term from the North American Electric Reliability Corporation (NERC) Glossary of Terms is used in this document, the term will be capitalized. Examples include: Facility, Facility Rating, Contingency and Real-time. Other capitalized terms are defined in this document; for example, System Voltage Limit is a capitalized term defined and used in this document. Such capitalized terms used in the SOL Methodology are listed in Appendix A.

B. Introduction and Purpose

This document is the Peak Reliability Coordinator (RC) System Operating Limit (SOL) Methodology for the Operations Horizon [NERC Standard FAC-011-3 R1]. The document establishes the methodology to be used in the Peak RC Area for determining SOLs and Interconnection Reliability Operating Limits (IROL) for use in the Operations Horizon pursuant to North American Electric Reliability Corporation (NERC) Reliability Standards FAC-011-3 and FAC-014-2.

Reliable operation of the Bulk Electric System (BES) in the Peak RC Area requires that all Transmission Operators (TOP) and the RC meet the minimum requirements stipulated in this SOL Methodology. It is not the intent of this SOL Methodology to limit the nature and range of studies and analyses TOPs and the RC may perform in ensuring acceptable system performance throughout the Operations Horizon.

The ultimate task of TOPs and the RC is to continually assess and evaluate projected system conditions as Real-time approaches with the objective of ensuring acceptable system performance in Real-time. These assessments are performed in an iterative fashion within the Operations Horizon, typically beginning as part of seasonal planning studies, followed by assessments performed as part of the IRO-017-1 Outage Coordination Process, followed by Operational Planning Analyses (OPA), and ultimately concluding with Real-time Assessments (RTA). Accordingly, these iterative studies should use anticipated transmission system configuration, generation dispatch and load levels, which are expected to improve in accuracy as Real-time approaches [NERC Standard FAC-011-3 R3.6].

C. Applicability

This SOL Methodology applies to the following entities within the Peak RC Area for developing SOLs and IROLs used in the Operations Horizon [NERC Standard FAC-011-3 R1.1]:

- TOPs
- Peak RC

This SOL Methodology defines Operations Horizon as follows:

> *A rolling 12-month period starting at Real-time (now) through the last hour of the twelfth month into the future.*

Because the SOL Methodology is applicable to the Operations Horizon, the concepts in this SOL Methodology apply to all sub-horizons within the Operations Horizon – seasonal planning, outage coordination, next-day, same-day and Real-time.

D. Drivers for the 2016 Major SOL Methodology Revision

The NERC-defined term SOL is used extensively in the NERC Reliability Standards; however, there has historically been much confusion with, and many widely varied interpretations and applications of, the SOL term. The prevalent confusion in the industry prompted the NERC Project 2014-03 Revisions to TOP and IRO Reliability Standards to issue the White Paper entitled, "System Operating Limit Definition and Exceedance Clarification." This White Paper served as a conceptual basis for developing the TOP and IRO Reliability Standards that have an effective date of April 1, 2017. Consequently, the NERC SOL White Paper, along with the WECC standing committee-approved Path Operator Task Force (POTF) recommendation, served as the conceptual basis for the 2016 major revision of the SOL Methodology for the Operations Horizon.

E. The Evolution of SOLs in the Western Interconnection

Much of the confusion associated with the SOL term in the West is due to the fact that changes have occurred in Peak's SOL Methodology over the last few years that differ from the historical paradigms and practices that have been in place in the West for a number of years. The SOL term as historically applied in the West has roots in the Operational Transfer Capability (OTC) concept that was reflected in the Reliability Management System (RMS) program in the late 1990s. The original RMS and subsequent regional reliability standard TOP-STD-007-0 required operation within OTC for the Paths listed in the "Major WECC Transfer Paths in the Bulk Electric System."

The OTC was a pre-determined Transfer Capability value which, if operated within, intended to prevent a predetermined limiting Contingency from resulting in exceedance of an identified thermal Facility Rating, System Voltage Limit or violation of stability criteria. For example, a thermally limited OTC was a Transfer Capability value that prevented an identified Contingency from causing exceedance of an identified Facility's Emergency Rating.

When TOP-STD-007-0 was revised as TOP-007-WECC-1, the guidance from NERC was to avoid the use of undefined terms such as OTC and to instead use approved NERC terms. The new concept of an SOL as established in several NERC FAC standards was beginning to emerge, and the conservative approach of replacing all references to OTC with the NERC term SOL was taken, even though OTC is more closely related to the NERC term Total Transfer Capability (TTC) than to System Operating Limit (SOL). The 30-minute time limit referenced in TOP-007-WECC-1 recognized that, if a Contingency event resulted in an SOL (OTC) exceedance, some reasonable time was needed to bring the system back to within the pre-determined SOL (OTC).

With respect to the 40 Paths listed in the "Major WECC Transfer Paths in the Bulk Electric System," the selection of these Paths also originated in the RMS program. There are no records of any technical criteria that resulted in the establishment of the list of Paths or why these particular Paths were selected and others were not. In Federal Energy Regulatory Commission (FERC) Order 752, FERC directed WECC to develop a means to provide consistency and transparency when making revisions to the list. WECC committed to publicly post any revisions to the WECC Transfer Path Table on the WECC website with concurrent notification to the Commission, NERC and industry. WECC has not changed the list of Paths since TOP-007-WECC-1 was approved by FERC in 2011.

Historically, the four subregional study groups have performed seasonal studies for WECC Paths to determine a seasonal "Path SOL" and corresponding Operating Procedures. A primary objective of these seasonal studies was to confirm that the WECC Path Rating was achievable, given the expected system conditions for that season. If seasonal studies demonstrated that the WECC Path Rating was expected to be achievable for that season, the WECC Path Rating was deemed to be the Path SOL for the season. If seasonal studies reached the WECC Path Rating (plus some margin) without encountering pre- or post-Contingency reliability issues, the Path was considered to be "flow limited". In such cases, the "flow limited" WECC Path Rating served as the seasonal Path SOL. If seasonal studies could not demonstrate that the WECC Path Rating was expected to be achievable for that season, the subregional study group would determine a lesser Path flow value that provided for acceptable thermal, voltage and stability criteria performance for the pre- and post-Contingency state. This value then was deemed to be the Path SOL for the season. Seasonal Path SOLs typically served as operational caps for the season.

Through the WECC POTF initiative, the new TOP/IRO standards and the accompanying NERC SOL White Paper, the industry has a much better understanding of what an SOL is, how the SOL term should be applied and how SOLs should be addressed in operations. As a result, the industry now realizes that there is no reason Facilities comprising these 40 Paths should be treated any differently than all the other elements of the BES. The new TOP and IRO Reliability Standards and the corresponding concepts in the 2016 major revision of the SOL Methodology represent a more accurate and reliable approach to achieving the ultimate reliability objective of demonstrating acceptable pre- and post-Contingency performance in operations than that characterized by the Path SOL paradigm.

The “RC Seasonal SOL Coordination Process” document referenced in the previous version of the SOL Methodology (revision 7.1), while still applicable for seasonal planning and coordination, is not referenced in this version of the SOL Methodology. TOPs are expected to continue with the “RC Seasonal SOL Coordination Process” until a replacement process is developed and implemented.

F. A Shift in Operations Paradigm

The WECC “Path SOL” concept embodies an operations paradigm characterized by the following:

- A study, assessment or analysis needs to be performed ahead of time to establish a Path SOL that achieves acceptable BES performance (pursuant to FAC-011-3 Requirement R2).
- The established Path SOL (a maximum flow value on an interface or cut plane) is then communicated and coordinated with operators and other impacted entities prior to implementation.
- Path Operators are then given Operating Plans to operate below the Path SOL with the presumption that doing so will result in acceptable pre- and post-Contingency system performance in Real-time operations.

Historically, when a Path exceeded its Path SOL in Real-time operations, the general practice was for the Path Operator to initiate actions to reduce that Path’s flow below the Path SOL[1].

[1] A formal request for clarification that Requirement R1 applies “to Transmission Operators, as defined in the NERC Glossary of Terms, and not to the *path operators* who have no compliance responsibilities under TOP-007-WECC-1 (TOP), other than any responsibilities they may have as a Transmission Operator for facilities in their respective Transmission Operator Areas.” (Emphasis added.) was provided in Appendix 1 of TOP-007-WECC-1a. The response to the request for clarification states, *“The NERC Functional Model 4, in effect at the time the standard was drafted, did not include Path Operators as an*

For the Paths listed in "Major WECC Transfer Paths in the Bulk Electric System" the Path SOL exceedance was required to be mitigated within 30 minutes. In the past, extreme actions such as load shedding has been exercised to mitigate Path SOL exceedances within 30 minutes, even if Real-time Assessments did not confirm the presence of an actual reliability issue.

While aspects of the Path SOL approach may have merit in some respects, the totality of this approach does not fully align with the principles characterized in the TOP and IRO standards, which present a different approach to achieving the ultimate reliability objective of demonstrating acceptable pre- and post-Contingency performance in operations:

Operations Planning Time Horizon

1. IRO-017-1 requires Planning Coordinators (PC) and TPs to share annual Planning Assessments with RCs (Requirement R3) and to jointly develop solutions with its respective RC for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon (Requirement R4). These requirements facilitate a transfer of information from planning to operations with regard to outage planning.

2. IRO-017-1 requires RCs to develop, implement, and maintain an outage coordination process (Requirement R1), and requires TOPs and Balancing Authorities (BA) to follow the process (Requirement R2). These requirements improve outage coordination within the operations planning time horizon leading up to Real-time operations.

3. TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1 require that the TOP and RC have an Operational Planning Analysis (OPA) to identify SOL exceedances. Note that SOL exceedance is described in the NERC SOL White Paper and that the revised definition of OPA addresses both the pre- and post-Contingency states.

4. TOP-002-4 Requirement R2 and IRO-008-2 Requirement R2 require that the TOP and RC have Operating Plan(s) to address potential SOL exceedances identified in the OPA.

5. TOP-002-4 Requirement R3 and IRO-008-2 Requirement R3 require that the TOP and RC notify entities identified in the Operating Plan(s) as to their role in those plan(s).

approved applicable entity; therefore, the document only applies to the stated Transmission Operators and does not apply to Path Operators."

6. TOP-002-4 Requirement R6 requires that the TOP provide its Operating Plan(s) for next-day operations to its RC.

Same Day and Real-time Time Horizons

7. TOP-001-3 Requirement R13 and IRO-008-2 Requirement R4 require that the TOP and RC ensure that a Real-time Assessment (RTA) is performed at least once every 30 minutes. Note that the revised definition of RTA addresses both the pre- and post-Contingency states.

8. TOP-001-3 Requirement R14 requires the TOP to initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

9. IRO-008-2 Requirement R5 requires the RC to notify impacted TOPs and BAs within its RC Area, and other impacted RCs as indicated in its Operating Plan, when the results of an RTA indicate an actual or expected condition that results in, or could result in, an SOL or IROL exceedance within its Wide Area. Note that the NERC SOL White Paper describes SOL exceedance.

Advanced applications, such as state estimation and Real-time Contingency Analysis (RTCA), which are widely used in the industry today, allow entities to assess pre- and post-Contingency performance for identifying SOL exceedance and to identify potential Cascading events in Real-time based on actual operating conditions. The TOP and IRO Reliability Standards require that TOPs and RCs have OPAs and RTAs to assess actual and expected system conditions for the pre- and post-Contingency states. The use of these technologies today fall in line with the new TOP and IRO Reliability Standards and definitions and requirements associated with OPA and RTA. The development and use of the Real-time tools improve reliability and allow better use of the BES beyond what the historical Path SOL concept permitted. The WECC Standing Committees' acceptance and endorsement of the POTF White Paper at the October 2014 Standing Committee meetings is indicative of the general belief that reliability can be improved and that operating efficiencies can be gained by taking steps to move away from the historical operating paradigm characterized by the Path SOL. This version of the SOL Methodology for the Operations Horizon represents one of those steps.

In order to understand and appreciate the shift in operations paradigm, it is important to note a few key definitions as found in the NERC Glossary of Terms:

Operational Transfer Capability (from the retired WECC standard TOP-STD-007-0):

The OTC is the maximum amount of actual power that can be transferred over direct or parallel transmission elements comprising:

- *An interconnection from one Transmission Operator area to another Transmission Operator area; or*
- *A transfer Path within a Transmission Operator area.*

Transfer Capability (approved definition from the NERC Glossary of Terms):

The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or Paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A."

Total Transfer Capability (approved definition from the NERC Glossary of Terms):

The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or Paths) between those areas under specified system conditions.

System Operating Limit (approved definition from the NERC Glossary of Terms):

The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- *Facility Ratings (Applicable pre- and post-Contingency equipment or Facility Ratings)*
- *Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)*
- *Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)*
- *System Voltage Limits (Applicable pre- and post- Contingency Voltage Limits)*

G. SOL Versus TTC

The foundational change with this SOL Methodology revision begins with the questions, "What is an SOL?" and "What is not an SOL?" The core idea underpinning this revision to the SOL Methodology is found in the clear distinction between SOL concepts and TTC concepts. Under this SOL Methodology revision, WECC Paths do not have single uniquely monitored SOLs unless the WECC Path is associated with an established transient or voltage stability limit; however, WECC Paths that are associated with scheduling will continue to have TTCs.

Ultimately, much of what has historically been considered an SOL is not considered an SOL under this SOL Methodology.

Under this SOL Methodology, SOLs are the Facility Ratings, System Voltage Limits, transient stability limits and voltage stability limits that are used in operations – any of which can be the most restrictive limit at any point in time pre- or post-Contingency. For example, if an area of the BES is at no risk of encroaching upon stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the System Voltage Limits in that area are the most limiting SOLs.

Per the NERC definition, TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or Paths) between those areas under specified system conditions. While it is expected that TTC respect pre- and post-Contingency reliability limitations associated with Facility Ratings, System Voltage Limits and stability limitations, the determination and communication of TTC is outside the scope of Peak's SOL Methodology.

Figure 1 – POTF Basic Principle shown below characterizes the decoupling of TTC and SOL.

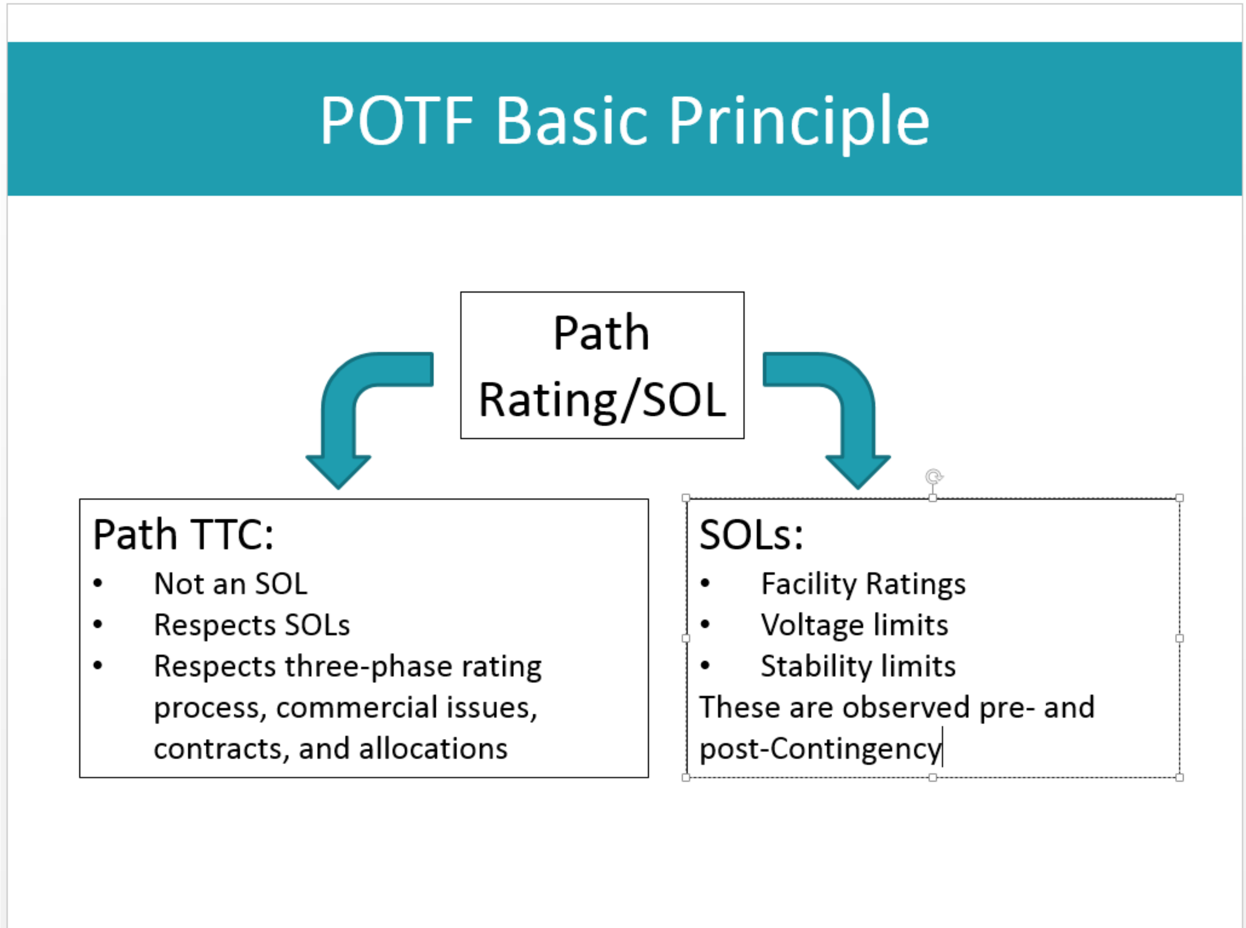


Figure 1 – POTF Basic Principle

H. Role of WECC Path Ratings

Under the historical Path SOL paradigm, Transfer Capability, scheduling limits, allocations, commercial considerations and historical reliability assessments performed in years past were all rolled up into a parameter that is monitored in Real-time operations as an SOL. In the Western Interconnection, Path SOLs were historically limited by and equal to the WECC Path Ratings unless studies indicated the need for a lower Path SOL value. While WECC Path Ratings have a basis in reliability studies performed in the planning horizon, the Path Rating process and the granted Path Rating exist primarily to safeguard the protection of investments and to ensure that the reliability impacts of new transmission projects are understood and that mitigations are agreed upon by all impacted entities before the transmission project becomes operational.

This SOL Methodology does not recognize WECC Path Ratings as SOLs. WECC Path Ratings are determined in the planning horizon per the voluntary WECC three-phase rating process. As stated earlier, this SOL Methodology recognizes SOLs to be the Facility Ratings, System Voltage Limits and stability limitations used in operations. If a WECC Path Rating is determined to be "stability limited" per the WECC three-phase rating process, this information can be used by TOPs and the RC to perform further analysis to determine if a stability limit should be established for use in the Operations Horizon; however, the "stability limited" WECC Path Rating itself is not automatically considered as a stability limit (SOL) for use in the Operations Horizon.

I. SOLs Versus Mechanisms to Prevent Limit Exceedance – the Role of Operating Plans

It is important to distinguish operating practices and strategies from the SOL itself. As stated above, the SOL is the actual set of Facility Ratings, System Voltage Limits and stability limits that are to be monitored for the pre- and post-Contingency state. How an entity remains within these SOLs can vary depending on the planning strategies, operating practices and mechanisms employed by that entity. For example, one TOP may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective. Regardless of the strategies employed, the Reliability Standards require that RTAs (per the revised definition of RTA) be performed at least once every 30 minutes to determine if any SOLs are exceeded.

The TOP and IRO standards portray an operating paradigm where the Operating Plan is the ultimate mechanism for ensuring operation within SOLs. The NERC Glossary of Terms defines an Operating Plan as follows:

> *A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.*

When an SOL is being exceeded in Real-time operations, the TOPs, BAs, and RCs are required to implement mitigating strategies consistent with their Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes.

Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability associated with the Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure BES performance is maintained as per approved FAC-011-3, Requirement R2. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings to prevent post-Contingency equipment damage and/or non-localized Cascading outages.

J. The Role of Nomograms and TTC in Operations Reliability

Nomograms are created ahead of time to predict a safe region whereby operating inside the region would be expected to result in acceptable pre- and post-Contingency system performance. They are a mechanism to describe interaction between elements or Paths with the objective of ensuring that the system is operated in a safe and reliable state while the use of related elements or Paths are simultaneously maximized. Nomograms may be used to provide System Operators with helpful guidance as part of an Operating Plan; however, they are not considered to be SOLs unless the nomogram represents a region of stability (i.e., the nomogram defines a stability limit).

Similarly, TTC is not an SOL, and thus it is not an operating parameter. However, if a TOP so chooses, the TOP may utilize TTC (and Transfer Capability concepts) as part of an Operating Plan as a means by which to achieve acceptable pre- or post-Contingency performance and thus to prevent SOL exceedances.

Note that exceeding a TTC value in Real-time operations does not constitute SOL exceedance. For example, if TTC for a WECC Path is determined to be 1200 MW in the north-to-south direction, and Real-time flow on that Path reaches 1300 MW, it cannot be concluded that an SOL is being exceeded. When Path flow is at 1300 MW, and RTAs indicate that no unacceptable pre- or post-Contingency performance is occurring, an SOL is not being exceeded. Conversely, if at a Path flow of 1000 MW, RTAs indicate that unacceptable pre- or post-Contingency performance is occurring, an SOL is being exceeded. If the SOL exceedance is occurring because of heavy transfers on the WECC Path, and Operating Plan for that SOL exceedance includes decreasing north-to-south flow on the WECC Path, or it is determined in real-time that decreasing north-to-south flow on the WECC Path is effective in mitigating the SOL, then it is expected that those mitigation measures be taken to address the SOL exceedance.

While TTCs and nomograms may serve as valuable mechanisms to prevent and/or mitigate SOL exceedances as part of an Operating Plan, these mechanisms are not a substitute for performing RTAs and do not absolve the TOP or the RC of its obligation to perform RTAs to identify SOL exceedance per the TOP and IRO Reliability Standards.

K. Path Operators, Path Operations, and TOP-007-WECC-1a

The SOL Methodology does not recognize the “Path Operator” as an operational entity. Consistent with the NERC Reliability Standards, the SOL Methodology recognizes TOPs and the RC as being responsible for operating within SOLs, though BAs may have a role in the Operating Plan to prevent or mitigate SOL exceedances. If, for example, heavy Path or interface flow is determined to be the cause of an SOL exceedance, it is expected that steps be taken by the associated TOPs and BAs per the pertinent Operating Plan to alleviate the condition by reducing flow on the Path or interface. The Operating Plans are expected to refer to the TOPs, BAs and the RC applicable to the Operating Plan.

While Peak will continue to monitor WECC Path flow relative to WECC Path TTC values for situational awareness purposes, Peak does not acknowledge the TTC as a SOL and does not require operation within TTC values or WECC Path Ratings. Peak monitors the entire BES for SOL exceedance (as described in the SOL Methodology) and implements Operating Plans as required to address instances of SOL exceedances as determined by RTAs.

TOP-007-WECC-1a

The remainder of Section K is effective until the retirement of TOP-007-WECC-1a is effective.

Until TOP-007-WECC-1a is retired, the 40 Paths in the list of “Major WECC Transfer Paths in the Bulk Electric System” will continue to have Path SOLs as they have had historically. SOLs for these 40 Paths should be established to respect pre- and post-Contingency acceptable performance for Facility Ratings, System Voltage Limits, stability limitations and WECC Path Ratings, as has been done historically[2]. The entity that currently establishes the SOL for a given Path is responsible for continuing to establish and communicate that Path SOL until the retirement of TOP-007-WECC-1a is effective.

[2] Anticipated emergency conditions may warrant operating to an SOL that is higher than the WECC Path Rating. Planning for such anticipated emergency conditions must be coordinated with the RC and impacted TOPs prior to day-ahead operations to ensure reliability issues are addressed and related Operating Plans are developed.

This provision applies only to the 40 Paths in the list of "Major WECC Transfer Paths in the Bulk Electric System." These 40 Paths are the only Paths for which Peak will accept a Path SOL in the historical and traditional sense (i.e., for non-stability related issues).

Upon the effective date of the retirement of TOP-007-WECC-1a, the SOL Methodology will no longer require SOLs for the 40 Paths in the list of "Major WECC Transfer Paths in the Bulk Electric System" to be established and communicated to Peak (unless the Path is associated with a stability limitation).

TOP-007-WECC-1a Path SOL Establishment and Communication Requirements

In summary, the following requirements apply while TOP-007-WECC-1a is effective:

1. Each TOP that currently establishes SOLs for Paths contained in the list of "Major WECC Transfer Paths in the Bulk Electric System" shall continue to establish SOLs for those Paths.

2. Each TOP that establishes SOLs for Paths contained in the list of "Major WECC Transfer Paths in the Bulk Electric System" per Item 1 above shall continue to communicate the Path SOL per historical communication protocols.

L. Acceptable System Performance

In the Peak RC Area, the BES is expected to be operated such that acceptable system performance is being achieved in both the pre- and post-Contingency state. This section describes acceptable system performance for the pre- and post-Contingency state [NERC Standard FAC-011-3 R2].

It is not the intent of this SOL Methodology to require more stringent BES performance than that stipulated in the prevailing NERC Transmission Planning (TPL) Reliability Standards and WECC TPL criteria; however, the SOL Methodology may prescribe specific performance criteria where the corresponding performance criteria in planning is non-specific.

1. Pre-Contingency: Acceptable system performance for the pre-Contingency state in the Operations Horizon is characterized by the following[3] [NERC Standard FAC-011-3 R2.1]:

    a. The BES shall demonstrate transient, dynamic and voltage stability.

[3] Note that these pre- and post-Contingency performance requirements are applicable to BES Facilities.

   b. All Facilities shall be within their normal Facility Ratings and thermal limits. (Refer to Figure 2 – SOL Performance Summary for Facility Ratings below.)

   c. All Facilities shall be within their normal System Voltage Limits.

   d. All Facilities shall be within their stability limits.

2. Post-Contingency (for single Contingencies listed in "3" below): Acceptable system performance for the post-Contingency state for single Contingencies in the Operations Horizon is characterized by the following (NERC Standard FAC-011-3 R2.2)[3]:

   a. The BES shall demonstrate transient, dynamic and voltage stability.

   b. All Facilities shall be within their emergency Facility Ratings and thermal limits. (Refer to Figure 2 – SOL Performance Summary for Facility Ratings below.)

   c. All Facilities shall be within their emergency System Voltage Limits.

   d. All Facilities shall be within their stability limits.

   e. Cascading or uncontrolled separation shall not occur.

3. The single Contingencies referenced in "2" above include the following[4]:

   a. Single-line-to-ground (SLG) or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer or shunt device [NERC Standard FAC-011-3 R2.2.1].

   b. Loss of any generator, line, transformer, or shunt device without a Fault [NERC Standard FAC-011-3 R2.2.2].

   c. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system [NERC Standard FAC-011-3 R2.2.3].

   Note that these Contingencies are reflective of the single P1 Contingency type described in Table 1 – Steady State & Stability Performance Planning Events found in NERC Reliability Standard TPL-001-4. Henceforth, these Contingencies will be referenced as single P1 Contingencies. Also note that the initial state for the P1 Contingency type in TPL-001-4 is "normal system," whereas the initial state for the

[4] The Contingencies identified in items (a) through (c) are the minimum Contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

P1 Contingency term used in this document is the actual or expected configuration of the system in the Operations Horizon, which is generally not "normal system," i.e., multiple Facilities may be out of service.

4. Acceptable system performance for credible multiple Contingencies (MC) are addressed in the next section.

5. The following Contingencies at a minimum are applicable for TOP assessments within the Operations Horizon:

    a. Single P1 Contingencies internal to the TOP Area.

    b. Credible MCs internal to the TOP Area.

    c. Any single P1 Contingencies and Credible MCs external to the TOP Area that are known to or may impact the TOP Area or system under study, as determined by the TOP. TOPs are responsible for determining whether Contingencies outside their TOP Area impacts them and for determining the external modeling necessary to support the evaluation of those Contingencies in their assessments.

6. Acceptable System Response: In determining the system's response to a single P1 Contingency, the following actions shall be acceptable [NERC Standard FAC-011-3 R2.3]:

    a. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the faulted Facility or by the affected area [NERC Standard FAC-011-3 R2.3.1].

    b. Interruption of other network customers [NERC Standard FAC-011-3 R2.3.2]:

        i. Only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or

        ii. If the Real-time operating conditions are more adverse than anticipated in the corresponding studies.

        iii. System reconfiguration through manual or automatic control or protection actions [NERC Standard FAC-011-3 R2.3.3]. Adequate time must be allowed for manual reconfiguration actions.

7. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology [NERC Standard FAC-011-3 R2.4].

Figure 2 – SOL Performance Summary for Facility Ratings provides an example of acceptable pre- and post-Contingency performance for a sample set of Facility Ratings. The Facility Ratings shown in the example are selected for illustration purposes only.

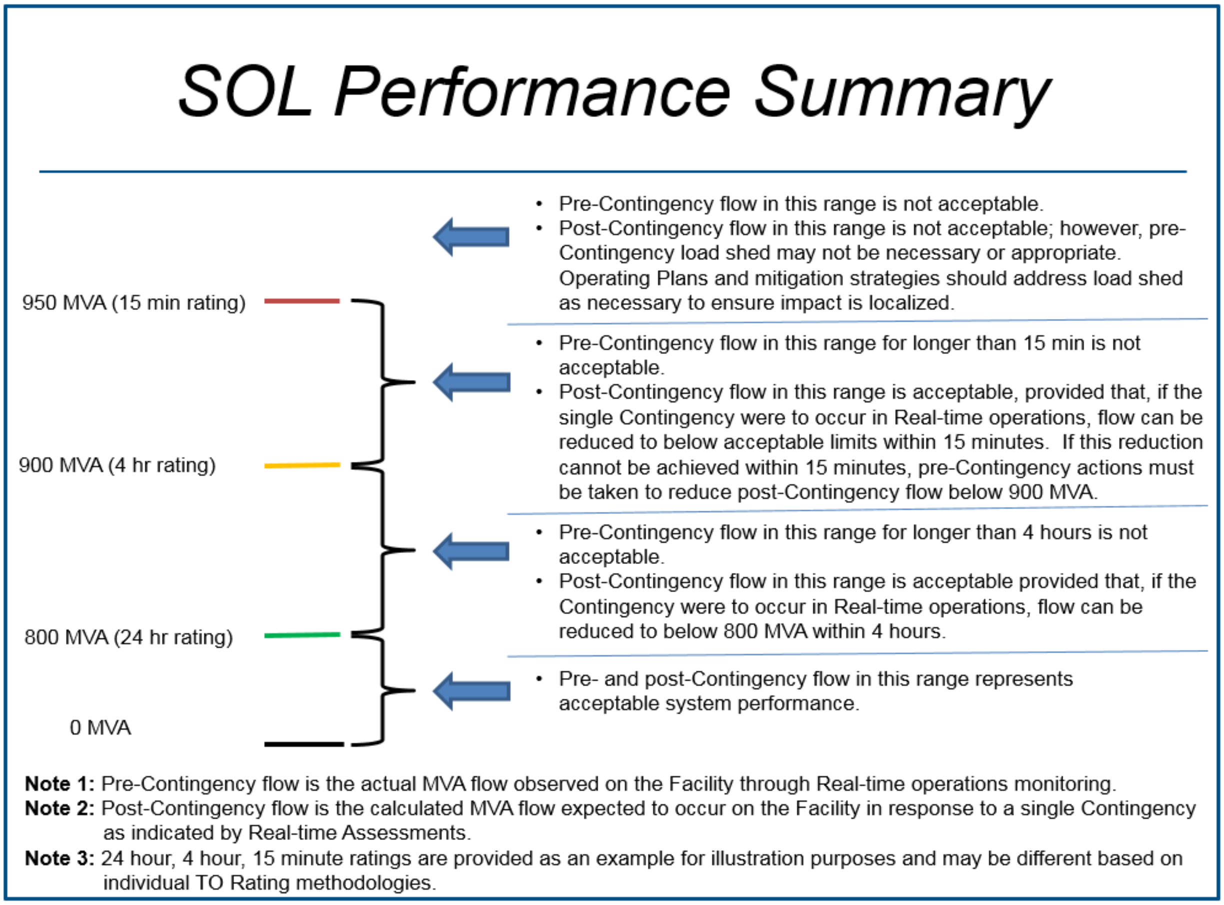


Figure 2 – SOL Performance Summary for Facility Ratings

M. Multiple Contingencies (MC) in Operations

This section of the SOL Methodology describes how MCs are to be addressed in the Operations Horizon [NERC Standard FAC-011-3 R3.2, 3.3, and 3.3.1].

Background – Determining an MC's Credibility for the Operations Horizon

MC management presents a significant challenge to engineers and System Operators. The primary challenge associated with managing MCs is the concept of MC "credibility." PCs and TPs are required by the TPL standards to assess a variety of MCs and to develop Corrective Action Plans when the system does not perform acceptably with regard to those Contingency event categories. The TPL standards do not provide PCs and TPs the latitude of determining which MCs are considered credible in the planning horizon. Rather, the MCs to be assessed are spelled out, and the performance requirements and expectations for those MCs are clear.

However, in the Operations Horizon, the concept of risk management comes into play with regard to MC considerations. In the Operations Horizon, MC credibility is a function of the plausibility (believability) of an event and the likelihood that it will occur. Ultimately, operators and engineers in the Operations Horizon need to decide whether or not the system needs to be operated to prevent the impacts of a particular MC event at any given time. It is recognized that TOPs in the Western Interconnection have a wide variety of unique operational issues and unique risk profiles that may result in different needs with regard to managing MCs in operations. The SOL Methodology presents a cohesive and unified approach to MC management while at the same time affording TOPs the flexibility to address their unique challenges and risk profiles.

Two Types of Credible MCs in the Operations Horizon

Credible MCs for the Operations Horizon can be broadly considered to fall into two categories – those that are "Always Credible" and those that are "Conditionally Credible."

- **Always Credible MCs** – There are MCs that, based on historical performance and TOP risk assessments, have a sufficiently high degree of likelihood of occurrence such that the TOP determines that the MC should be protected against in all phases of the operations planning process and in Real-time operations. The credibility of these MCs does not change based on observable operating conditions, but rather their credibility is static based on TOP performance and risk assessments.

- **Conditionally Credible MCs** – On the other hand, there are MCs whose credibility is a function of observable system conditions. For these, the MC is credible only when the observable system conditions are present. When the observable system conditions are not present, the MC is not credible. Examples of this type of MC are those that become credible upon known and observable threats like fires, or adverse weather risks such as flooding, icing, tornados. Similarly, when a breaker has a low-gas alarm, this condition can pose a risk that the breaker may not operate as anticipated should it be called upon to clear a Fault. In such cases, System Operators might operate the system to account for the possible failure of this breaker during those conditions. Such Conditionally Credible MCs present operators and engineers with the challenge of determining which of these, if any, should be pre-identified for development of a standing MC-specific Operating Plan that can be applied should the conditions arise that would render the MC as being credible in operations. The SOL Methodology provides TOPs with the flexibility to optionally pre-identify potential risks associated with Conditionally Credible MCs and to develop standing Operating Plans ahead of time for those MCs should the associated conditions occur in Real-time operations.

TOPs should generally consider the following MC types when determining any Always Credible MCs for operations. These Contingency types serve as a starting point for the internal risk assessment for determining Always Credible MCs. Upon review of these MC types, the TOP should determine which of these, if any, are designated as Always Credible MCs for operations:

1. Bus Fault Contingencies (though this is listed as a P2 single Contingency in TPL-001-4, it is considered a lower-probability, higher-impact event in operations and therefore is considered along with other MCs for both credibility determination and performance requirements)
2. Stuck breaker Contingencies (reflective of a P4 Contingency in TPL-001-4)
3. Relay failure Contingencies where there is no redundant relaying (reflective of a P5 Contingency in TPL-001-4)
4. Common structure Contingencies (reflective of a P7 Contingency in TPL-001-4)
5. Any of the MCs that have been determined by its PC to result in stability limits (provided to the RC per FAC-014-2 R6) [NERC Standard FAC-011-3 R3.3.1]

Note that N-1-1 Contingency types (reflective of P3 and P6 Contingencies in TPL-001-4) are not under consideration under the auspices of MC credibility. Specific combinations of two overlapping single Contingencies is not an issue of credibility or non-credibility. For such combinations of single Contingencies, it is a matter of knowing which combinations to be prepared for based on known issues with those specific combinations. Such operational risks are expected to be addressed through Operating Plans as these risks are identified. Reference the *IROL Establishment* section of the SOL Methodology for more information on N-1-1 risk assessment.

Requirements for Identifying Always Credible MCs in Operations

6. MCs that are considered Always Credible for operations include those that are determined to have static credibility through all phases of the operations planning process (seasonal and other special studies, outage coordination assessments, and Operational Planning Analyses) and in Real-time operations (including Real-time Assessments). These MCs are not a function of observable operating conditions.
7. TOPs shall document the list of Always Credible MCs per the RC instructions posted on Peak's website. Note that the RC instructions require each Always Credible MC to

be accompanied by a rationale for its credibility. The list of Always Credible MCs in operations resides in the secured area of the peakrc.org website and is accessible by TOPs and BAs that have access to the website. If a TOP has no Always Credible MCs identified, the TOP should indicate that to the RC.

8. When developing the list of Always Credible MCs for operations, TOPs are expected to perform an internal evaluation of historical MC performance and an internal risk assessment to determine the MCs internal to their TOP Area that are considered Always Credible for operations based on factors and issues that are unique to their TOP Area.

9. It is the primary responsibility of the TOP in whose TOP Area the MC Facilities reside to determine MC credibility. However, because the RC is the highest authority in the Interconnection, the RC has the authority to determine an MC's credibility that supersedes a TOP's designation. Should the RC exercise such authority, the RC shall perform an evaluation of historical MC performance and a risk assessment based on the factors and issues driving the RC to supersede the TOP's determination, and the RC shall share this information with impacted TOPs.

10. When a MC terminates in different TOP Areas, the TOPs are expected to collaborate and agree on the MC credibility.

11. If an impacted TOP challenges or disagrees with a TOP's decision or rationale for a MC's credibility, or if TOPs cannot agree on the credibility of the MC that impacts their TOP area, the TOPs involved are expected to coordinate with the RC to reach a resolution. If agreement/resolution cannot be achieved through collaboration, the RC has the authority to make final determination of the MC credibility. In its final determination, the RC is expected to coordinate with the applicable PC(s) and to consider how the system was planned, built and is intended to be operated. The RC will document the final resolution.

12. Contingencies more severe than bus Fault Contingencies, stuck breaker Contingencies, relay failure Contingencies and common structure Contingencies are considered to be extreme events and are generally not under consideration as Always Credible MCs for the Operations Horizon; however, exceptions may exist due to the severe and widespread adverse consequences of the MC. If there are any extreme Contingencies that the TOP or the RC determines to be Always Credible for operations, Peak and the impacted TOPs are expected to collaborate to determine how those extreme events are to be addressed in operations planning and in Real-time operations.

Addressing Conditionally Credible MCs in Operations

13. Conditionally Credible MCs are not required to be pre-identified or included along with the list of Always Credible MCs. However, if the TOP optionally pre-identifies any Conditionally Credible MCs and creates a standing Operating Plan for that MC, the TOP shall provide that Operating Plan to Peak per RC instructions for awareness purposes. If such pre-identified Operating Plans impact or involve other TOPs, then the Operating Plan should be developed in collaboration with the impacted/involved TOPs and communicated to those TOPs.

14. Conditionally Credible MCs become credible when the Conditionally Credible MC poses a risk to reliability due to a known, foreseeable or observable threat. The TOP in whose TOP Area the MC Facilities reside is responsible for determining when a Conditionally Credible MC becomes credible and when it ceases to be credible.

15. When a Conditionally Credible MC becomes credible, the TOP in whose TOP Area the MC Facilities reside must notify the RC and other TOPs known or expected to be impacted by the MC. The TOP in whose TOP Area the MC Facilities reside must collaborate with the RC and impacted TOPs to create and implement an Operating Plan (or to implement a pre-determined Operating Plan) to address the known and observable risk associated with the Conditionally Credible MC.

16. Impacted TOPs and the RC are expected to include the Conditionally Credible MCs in their respective studies while the Conditionally Credible MC is credible.

17. When Conditionally Credible MCs become credible and the MC impacts multiple TOPs, the RC will collaborate with impacted TOPs to ensure that the MC is being addressed in a coordinated manner.

Performance Requirements for Always Credible and Applicable Conditionally Credible MCs

18. The MC shall not result in:

    a. System-wide instability

    b. Cascading

    c. Uncontrolled separation

19. It is acceptable for Always Credible and applicable Conditionally Credible MCs to result in exceedance of emergency Facility Ratings and emergency voltage limits, provided these SOL exceedances do not result in the conditions described in item 18 above. The Cascading test described in the *Instability, Cascading, Uncontrolled*

Separation and IROLs section of the SOL Methodology applies when determining potential Cascading.

20. Always Credible and applicable Conditionally Credible MCs are expected to meet these performance requirements in all phases of assessments in the Operations Horizon – seasonal planning, special studies, outage coordination studies, OPAs and RTAs.

21. A TOP may choose to adopt more stringent performance requirements for Always Credible or applicable Conditionally Credible MCs; however, a TOP's self-imposed, more stringent performance requirements may not require neighboring/impacted TOPs to accommodate these more stringent requirements. TOPs are at liberty to agree on more stringent performance requirements for credible MCs.

22. Peak will neither operate – nor require that TOPs operate – to more stringent criteria than the criteria specified in item 18 above.

Requirements for the Treatment of Credible MCs in the Operations Horizon

23. The RC must include Always Credible MCs in RC assessments (seasonal assessments, special studies, outage coordination studies, OPAs, RTAs). The RC must include Conditionally Credible MCs in RC assessments while the MC is credible.

24. TOPs must include their own Always Credible MCs in TOP assessments (seasonal assessments, special studies, outage coordination studies, OPAs, RTAs). The TOP must include its own Conditionally Credible MCs in TOP assessments while the MC is credible.

25. If TOP seasonal assessments, special studies, outage coordination studies or OPAs are validated to indicate that an Always Credible or applicable Conditionally Credible MC does not meet MC performance requirements described in the SOL Methodology, the TOP must develop an Operating Plan to provide for acceptable performance for the MC. It is possible that an IROL may need to be established to address the reliability risk. Reference the *IROL Establishment* section of the SOL Methodology for more information. Similarly, if TOP RTAs are validated to indicate that a credible MC does not meet MC performance requirements described in the SOL Methodology, the TOP must implement an Operating Plan to mitigate the unacceptable system performance for the credible MC.

26. Peak includes credible MCs in RC assessments (both Always Credible MCs and any applicable Conditionally Credible MCs that are communicated to the RC) and evaluates those MCs against the MC performance requirements. Peak applies the

Cascading test as described in the section entitled *Instability, Cascading, Uncontrolled Separation and IROLs* when determining potential Cascading. Peak does not evaluate credible MCs against more stringent performance requirements. If Peak's special studies, outage coordination studies or OPAs are validated to indicate that a credible MC does not meet MC performance requirements, an Operating Plan must be developed to provide for acceptable performance for the credible MC. Similarly, if Peak's RTAs are validated to indicate that a credible MC does not meet MC performance requirements described in the SOL Methodology, an Operating Plan must be implemented to mitigate the unacceptable system performance for the credible MC. Peak does not include non-credible MCs in RC assessments.

27. If an MC is not declared as Always Credible by the TOP in whose TOP Area the MC Facilities reside and is not posted on the peakrc.org website, then the MC is not required to be honored in the Operations Horizon (seasonal assessments, special studies, outage coordination assessments, OPAs, RTAs). Note that Conditionally Credible MCs that become credible in operations are addressed separately.

28. Note that not "all" Contingencies within a TOP Area (single P1 Contingencies or credible MCs) are expected to be included in certain types of analyses. For example, time-domain, PV/QV and transfer studies are not conducive to analyzing as many Contingencies as can be done in steady-state Contingency Analyses performed as part of a power flow. For studies such as time-domain analyses and PV/QV analyses, TOPs and the RC are expected to include those Contingencies that are the most impactful to the situation based on experience, engineering judgment and historical analysis.

29. If a TOP determines that an MC in its TOP Area is non-credible, yet a neighboring/impacted TOP desires to include that non-credible MC in its assessments, the neighboring/impacted TOP may do so; however, the neighboring/impacted TOP cannot require other TOPs to address reliability issues related to the non-credible MC and cannot require any other TOP to honor that MC in operations or in the development or implementation of Operating Plans.

N. SOL Exceedance

SOL exceedance occurs when acceptable system performance requirements as described in approved FAC-011-3 are not being met, be it in seasonal planning studies, special studies, outage studies, OPAs or RTAs. In other words, unacceptable system performance equates to SOL exceedance. This SOL Methodology considers SOL exceedance to be a condition characterized by any of the following:

1. Actual/pre-Contingency flow on a Facility is above the Normal Rating
2. Calculated post-Contingency flow on a Facility is above the highest Emergency Rating
3. Actual/pre-Contingency bus voltage is outside normal System Voltage Limits
4. Calculated post-Contingency bus voltage is outside emergency System Voltage Limits
5. Operating parameters indicate a Contingency could result in instability

O. Allowed Uses of Automatic Mitigation Schemes in the Operations Horizon

This section describes how the SOL Methodology addresses the allowed uses of automatic mitigation schemes in the Operations Horizon, both those that shed load as part of the scheme as well as those that do not. This document is applicable to Remedial Action Schemes (RAS) and other non-RAS schemes that automatically take mitigation action in response to system conditions or Contingency events [NERC Standard FAC-011-3 R3.5].

The revised NERC definition of RAS has an effective date of April 1, 2017. As a result, some automatic schemes that were not previously considered a RAS may be considered a RAS under the new definition, and vice versa. Item “e” in the RAS definition excludes schemes applied to an Element for non-Fault conditions that remove that Element from service to protect it from damage due to overload conditions. Such schemes, while not considered a RAS, are included here within the broader context of automatic mitigation schemes.

The following items describe the allowed use of automatic mitigation schemes in the Operations Horizon, including both non-load-shed automatic schemes and load-shed automatic schemes:

1. If a TOP relies upon an automatic scheme for providing acceptable performance for single Contingencies or credible MCs, then the actions of the automatic scheme must be modeled in assessment tools or otherwise included in the TOP's analysis and the RC's analysis as applicable.
2. If at any time OPAs or other prior analyses indicate that the automatic scheme either fails to mitigate the reliability issue, potentially causes other reliability issues or could result in a more significant reliability risk, or if the automatic scheme is expected to be unavailable, the TOP must develop an Operating Plan in coordination with

impacted TOPs and the RC, that contains pre-Contingency mitigation actions to address the reliability issue.

3. If at any time RTAs indicate that the automatic scheme either fails to mitigate the reliability issue, potentially causes other reliability issues or could result in a more significant reliability risk, or if the automatic scheme is unavailable, the TOP must initiate an Operating Plan in coordination with impacted TOPs and the RC, to take pre-Contingency mitigation actions to address the reliability issue.

4. Automatic schemes that have a single point of failure may not be utilized to prevent System instability, Cascading or uncontrolled separation from occurring in response to single P1 Contingencies or credible MCs. If any TOP seeks an exception, the TOP shall coordinate with the RC and request to be granted an exception until the necessary redundancies can be put in place and the automatic scheme classification is updated per the applicable standard or regional criteria. Exceptions may be made only for conditions that would otherwise require pre-Contingency load shedding. If operational situations arise where an automatic scheme that has a single point of failure must be relied upon to avoid pre-Contingency load shedding, such conditions must be coordinated and approved for use by the RC.

5. If an automatic scheme is relied upon to prevent System instability, Cascading or uncontrolled separation in the transient or post-transient timeframe, the TOP studies must assess those timeframes to ensure that the automatic action occurs in time to prevent System instability, Cascading or uncontrolled separation.

6. Several automatic schemes are intended and designed to address certain non-credible MCs (including extreme event Contingencies). In the Operations Horizon, these schemes are allowed to be relied upon to meet their intended design objectives for those non-credible and extreme event Contingencies; however, the SOL Methodology does not require assessment of – and therefore, determination of acceptable performance for – non-credible and extreme event Contingencies in the Operations Horizon.

Requirements Specific to Non-Load-Shed Automatic Schemes

Non-load-shed schemes include those that do not shed load as part of the mitigation action of that scheme. Examples of such schemes include generation drop schemes and transmission reconfiguration schemes.

7. Non-load-shed automatic schemes are not as restricted in their use as are load-shed automatic schemes. Accordingly, use of non-load-shed automatic schemes is allowed for the same conditions where the use of load-shed automatic schemes is allowed.

8. Non-load-shed schemes may be used as an acceptable automatic post-Contingency mitigation action, provided the general requirements listed in items 1-6 above are met.

9. If a TOP intends to use a non-load-shed scheme in a manner for which the scheme was not intended and designed, and that intended use impacts other TOPs, the TOP must coordinate with impacted TOPs prior to reliance on that scheme.

<u>Requirements Specific to Load-Shed Automatic Schemes</u>

Load-shed schemes include any scheme that automatically sheds load in response to Contingency events. Such schemes include, but are not limited to, load-shed RAS, Underfrequency Load Shedding (UFLS) schemes, Undervoltage Load Shedding (UVLS) schemes (including UVLS Programs) or other non-RAS schemes that automatically shed load in response to Contingency events. Note that the term “UVLS” refers to distributed UVLS and includes UVLS Programs as defined in the NERC Glossary of Terms. RAS or other relay schemes that monitor transmission voltages and drop load based on those voltages are not considered as a UVLS.

Definition of Undervoltage Load Shedding Program from the NERC Glossary of Terms:

> *An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.*

In principle, the use of load-shed schemes in the Operations Horizon must take into consideration how the scheme was intended and designed to be utilized.

The following items describe the allowed use of load-shed schemes in the Operations Horizon:

10. In general, load-shed schemes should be used and relied upon for the conditions/events for which the load-shed scheme was intentionally designed. Though there may be scenarios where it is appropriate to use or rely upon load-shed schemes to address Contingency events for which the load-shed scheme was not designed, such instances should be minimized and should be thoroughly investigated and studied in the operations planning timeframe to ensure that reliance on these schemes is reliable, prudent, consistent with sound engineering judgment and utility practice, and reflects appropriate risk management principles.

11. There may be conditions where the operational consequences of some load-shed schemes are such that TOPs in collaboration with the RC may choose to implement

an Operating Plan that prevents the load-shed scheme from triggering for a given operating condition or Contingency event.

12. Some load-shed schemes are intended and designed to address certain credible MCs. If a load-shed scheme is intended and designed to address a specific credible MC, then the load-shed scheme is allowed to support economic operations and is allowed for consideration in the Operations Horizon, for:
    a. Assessing acceptable post-Contingency system performance for those Contingencies
    b. Determining whether or not a stability limit or an IROL needs to be established
    c. Calculating the value of the stability limit or the IROL, once it has been determined that there is a need to establish a stability limit or an IROL
13. Load-shed schemes may be relied upon and utilized in operations for single P1 Contingencies if the scheme's impact is limited to a small amount of load in the local network area. However, load-shed schemes may not be relied upon or utilized in operations for single P1 Contingencies to support economic operations.[5]
14. There are times when a planned or forced outage of a Facility causes a MC in planning to become a single P1 Contingency in operations[6]. When this type of

[5] The intent is to, if at all possible, limit reliance on such load-shed schemes to those that were designed and implemented per the allowances specified in Table 1 of TPL-001-4 for P1 Contingencies. While Table 1 TPL-001-4 indicates that Non-Consequential Load Loss is not allowed for single P1 Contingencies, the table includes footnote 12 which states, *"An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction."*

[6] Example: A UVLS Program is designed in the planning horizon to prevent a P7 common structure Contingency from resulting in instability. The structure carries two transmission lines. One of these two lines is removed from service on a planned or forced outage. From an operations perspective, the loss of

scenario occurs for MCs (or for certain P2 Contingencies that remove multiple Elements) for which a load-shed scheme was designed, the scheme can be relied upon and utilized in operations according to the following:

a. When a forced or urgent[7] outage of a Facility causes a MC in planning to become a single P1 Contingency in operations, the load-shed scheme can be relied upon to provide for acceptable system performance for the next single P1 Contingency; however, System Operators shall take appropriate action up to, but not necessarily including load shedding, to (if at all possible), re-position the system in response to the forced or urgent outage such that the load-shed scheme is not required to provide for acceptable system performance for the next single P1 Contingency[8]. In such conditions, Real-time studies, operations/engineering judgment and the operational consequences of the load-shed scheme should be considered in the overall risk management exercise when determining the appropriate course of action.

b. When a planned outage of a Facility causes a MC in planning (for which a load-shed scheme was designed) to become an N-1 Contingency in operations, TOPs shall develop an outage-specific Operating Plan to take appropriate action up to, but not including load shedding, to (if at all possible) pre-position the system such that the load-shed scheme is not required to provide for acceptable system performance for the next single P1 Contingency for the duration of the planned outage[7]. In planned outage scenarios, load-shed schemes are not allowed to be used to support economic operations for the next worst single P1 Contingency. If at all possible, reliance on load-shed schemes for single P1 Contingencies during planned outages should be limited to addressing local area thermal or voltage issues. Any planned outage that requires reliance on load-shed schemes to prevent instability, Cascading or uncontrolled separation during planned outages for the next single P1 Contingency will be allowed only upon the express review and approval by the RC.

the remaining line now represents an N-1 Contingency during the period of time that the outage of the other line is in effect.

[7] Reference IRO-017-1 Outage Coordination Process for description of forced and urgent outage types.

[8] Appropriate actions may or may not include sectionalizing. If sectionalizing places more load at risk, then reliance on load-shed scheme is acceptable if the scheme was designed for the intended purpose.

i. If at all possible, planned outages should be scheduled for a time when system conditions are such that a load-shed scheme is not necessary to provide for acceptable system performance for the next single P1 Contingency during the planned outage.

ii. If it is not possible to schedule the planned outage according to item i), and reliance on load-shed scheme cannot be avoided for the next worst single P1 Contingency during the planned outage, the load-shed scheme action must be simulated and studied in TOP assessments and in RC assessments as applicable, and those studies must demonstrate that the load-shed scheme action provides for acceptable post-Contingency system performance.

A summary table of key aspects of the allowed uses of automatic mitigation schemes in the Operations Horizon is provided in Appendix C.

P. Coordination Responsibilities

It is important that TOPs collaborate and coordinate with one another when determining Always Credible MCs and when establishing each of the three types of SOLs (Facility Ratings, System Voltage Limits and stability limitations). Because inadequate collaboration and coordination can result in adverse consequences for the reliability of the BES, TOPs should take deliberate steps to proactively work with neighboring or impacted entities to ensure that Always Credible MCs and SOLs are coordinated prior to submission to Peak.

For example, when establishing Facility Ratings for use in operations, TOPs are expected to coordinate with their respective TOs and with adjacent TOPs to ensure that Facility Ratings are coordinated. Similarly, when establishing System Voltage Limits, TOPs are expected to work with TOs and adjacent or impacted TOPs to establish System Voltage Limits that provide for reliable and orderly operations.

The lack of coordination can have unintended operational or reliability consequences that can be avoided through proper coordination executed in the spirit of being a good neighbor.

If TOPs are unable to reach a resolution on matters related to TOP-to-TOP collaboration and coordination, the TOPs should consult with Peak to help resolve the issue.

Q. SOLs Used in the Operations Horizon

System Operating Limits used in the Operations Horizon include Facility Ratings, System Voltage Limits and stability limitations. This section describes each of these three types of SOLs.

Facility Ratings

This section focuses on Facility Ratings and describes how Facility Ratings are to be established and communicated to the RC.

SOLs shall not exceed associated Facility Ratings [NERC Standard FAC-011-3 R1.2]. More specifically, Facility Ratings are SOLs, and any exceedances of these SOLs should be prevented and mitigated per the applicable TOP and IRO NERC Reliability Standards.

Pursuant to FAC-008-3, each Transmission Owner (TO) and Generation Owner (GO) is required to establish Facility Ratings consistent with their corresponding Facility Ratings Methodology. Per FAC-008-3, these Facility Ratings are required to include Normal Ratings and Emergency Ratings. While Facility Ratings originate from the TO and the GO, it is the TOP that determines which of those TO/GO-provided Facility Ratings will ultimately be used in operations.

It is important for reliability that the RC and the TOPs within the RC Area use the same set of Facility Ratings in the Operations Horizon, including seasonal planning studies, special studies, outage coordination studies, Operational Planning Analyses (OPA) and Real-time Assessments (RTA).

Facility Ratings that are used in the Operations Horizon shall be determined by the TOP in whose TOP Area the Facilities reside according to the following process:

1. It is the responsibility of the TOP in whose TOP Area the transmission Facilities reside to obtain the Facility Ratings from the associated TO[9].

2. The TOP shall determine which Facility Ratings (both Normal Ratings and Emergency Ratings, as defined in the NERC Glossary of Terms) provided by the TO are to be used in the Operations Horizon, expressed in MVA (with an associated kV) or Amps. Emergency Ratings shall include the time value that is associated with that

[9] Generation Facility data, (including Generator Facility Ratings and generator step-up transformer information) is addressed outside of the SOL Methodology. Reference Peak's IRO-010-3 Data Specification for required generator data.

Emergency Rating. For example, a 2-hour 300 MVA rating, or a 30-minute 500 MVA rating.

3. It is the responsibility of the TOPs to agree on the Facility Ratings of Facilities that are operated by more than one TOP or Facilities that connect adjacent TOPs. If the TOPs cannot agree, the most limiting Facility Rating will apply as a default.

4. For any given Facility, Peak Reliability analysis tools are able to model three Facility Ratings for any given season – one Normal Rating and two Emergency Ratings:

    a. Normal Rating (NORM)

    b. Emergency Rating #1 (EMER #1)

    c. Emergency Rating #2 (EMER #2)

5. If, for a given Facility, the TOP uses only one Emergency Rating in the Operations Horizon, Peak will use that Facility Rating in both the EMER #1 and the EMER #2 database field. If, for a given Facility, the TOP does not use an Emergency Rating and only uses a single Facility Rating value for the Facility, Peak will use that value in the NORM, EMER #1, and EMER #2 database fields.

6. If, for a given Facility, the TOP uses more than three Facility Ratings in its analysis tools, Peak will implement a subset of these Facility Ratings to its model according to the following:

    a. NORM database field – Peak will use the TOP-provided Normal Rating

    b. EMER #1 database field – Peak will use the TOP-provided Emergency Rating that has the second shortest time value (reference examples below)

    c. EMER #2 database field – Peak will use the TOP-provided Emergency Rating that has the shortest time value, no less than a 15-minute Emergency Rating (reference examples below)

Example #1:

TOP Ratings Used in Operations	Peak Modeled Ratings
Normal Rating = 300 MVA	Peak modeled NORM Rating
8-hour Emergency Rating = 400 MVA	
2-hour Emergency Rating = 500 MVA	
1-hour Emergency Rating = 550 MVA	Peak modeled EMER #1 Rating
20-min Emergency Rating = 600 MVA	Peak modeled EMER #2 Rating

Example #2:

TOP Ratings Used in Operations	Peak Modeled Ratings
Normal Rating = 300 MVA	Peak modeled NORM Rating
4-hour Emergency Rating = 400 MVA	
2-hour Emergency Rating = 500 MVA	
1-hour Emergency Rating = 550 MVA	
30-min Emergency Rating = 600 MVA	Peak modeled EMER #1 Rating
15-min Emergency Rating = 650 MVA	Peak modeled EMER #2 Rating
5-min Emergency Rating = 700 MVA	

7. Emergency Facility Ratings with a time value less than 15 minutes can only be used for extenuating circumstances and only when its use is verified and acceptable by both the TOP and the RC.

8. Peak's analysis tools are also able to utilize dynamic Facility Ratings in Real-time operations. If a TOP uses dynamic Facility Ratings in Real-time operations analysis tools, the TOP shall coordinate with Peak modeling engineers to facilitate Peak's implementation of those dynamic Facility Ratings in Peak's models for use in Real-time operations. The objective is for the TOP and the RC to be using the same Facility Ratings at any given point in time.

Reference Table 1 – Facility Ratings Table and Examples for sample Facility Ratings that may be used in the Operations Horizon.

Facility	Normal Rating	Emergency Rating #1	Emergency Rating #2
Facility Name	TOP-provides Normal Rating (continuous operation rating) Peak uses this for the NORM limit	TOP-provides short-term Emergency Rating #1 Peak uses this for the EMER #1 limit If the TOP uses more than three Facility Ratings in its analysis tools, Peak will use the TOP-provided Emergency Rating that has the second shortest time value.	TOP-provides short-term Emergency Rating #2 Peak uses this for the EMER #2 limit If the TOP uses more than three Facility Ratings in its analysis tools, Peak will use the TOP-provided Emergency Rating that has the shortest time value, no less than a 15-minute Emergency Rating.
Example 1	300 MVA	450 MVA (4-hour)	550 MVA (1-hour)
Example 2	200 MVA	300 MVA (4-hour)	300 MVA (4-hour)
Example 3	600 MVA	800 MVA (1-hour)	900 MVA (15-min)
Example 4	100 MVA	175 MVA (2-hour)	225 MVA (30-min)
Example 5	500 MVA	500 MVA (time N/A)	500 MVA (time N/A)

Example 6	Ambient temperature calculated	Ambient temperature calculated	Ambient temperature calculated

Table 1 – Facility Ratings Table and Examples

Communication of Facility Ratings

9. The TOP shall communicate to the RC the following Facility Ratings:
    a. The Facility Ratings it uses in operations as implemented in its analysis tools.
    b. If a TOP uses different sets of Facility Ratings for different seasons, the TOP shall communicate those seasonal Facility Ratings to the RC.
10. TOPs are responsible for communicating to the RC any changes to the Facility Ratings used in operations. This includes any temporary Facility Ratings that may be implemented and changes to seasonal Facility Ratings (e.g., when the TOP stops using summer seasonal ratings and begins using fall seasonal ratings.) Once communicated, Peak will implement the changes in its models.
11. TOPs shall communicate Facility Ratings according to the method described in the RC instructions.

System Voltage Limits

System Operating Limits used in the Operations Horizon include Facility Ratings, System Voltage Limits and stability limitations. This section focuses on System Voltage Limits and describes how System Voltage Limits are to be established and communicated to the RC.

System Voltage Limits are defined as follows for the purposes of the SOL Methodology:

> *The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.*

System Voltage Limits are SOLs. System Voltage Limits apply to the BES and are typically monitored at physical substation buses, though other points in the system may be monitored as necessary.

It is important that the TOPs and the RC use the same set of System Voltage Limits for assessments within the Operations Horizon, including seasonal planning studies, outage coordination studies, special studies, OPAs and RTAs. While it is acceptable to use general or more stringent voltage limits to flag potential reliability issues, the established System Voltage Limits must be ultimately used for assessments within the Operations Horizon[10].

Operating within Low System Voltage Limits ensures that the buses across the BES have adequate voltage to support reliable operations of the BES.

Operating within High System Voltage Limits ensures that the system does not operate at unacceptably high voltage levels, and that the equipment connected to the bus is not subjected to voltages that exceed the equipment voltage rating. When equipment is subjected to voltages that are higher than the equipment's voltage rating, the equipment may be damaged and may not function properly when called upon.

It is important to distinguish System Voltage Limits from voltage stability limits. System Voltage Limits address the steady state voltage of the system, while voltage stability limits exist specifically to address voltage instability risks based on post-transient analysis. Voltage stability limits are addressed in a subsequent section of the SOL Methodology.

TOPs shall establish System Voltage Limits according to the following:

1. TOPs are responsible for the establishment of System Voltage Limits for the substation buses that exist within their TOP Area. TOPs have flexibility to modify these limits as necessary based on actual or expected conditions within the bounds of the subsequent requirements listed below, provided the changes are justified for reliability and a technically sound rationale can be provided.

2. System Voltage Limits are applied to BES substation buses excluding the following:

    a. Line side series capacitor buses

    b. Line side series reactor buses

    c. Dedicated shunt capacitor buses

    d. Dedicated shunt reactor buses

    e. Metering buses, fictitious buses or other buses that model points of interconnection solely for measuring electrical quantities, and,

    f. Other buses specifically excluded by the TOP in whose TOP Area the buses reside, provided the exclusion is justified for reliability and is documented

[10] Some entities might use generic (or more stringent) voltage limits that may exist in planning models that do not reflect the System Voltage Limits that are used in actual operations.

3. While it is expected that TOPs take steps to coordinate the development of System Voltage Limits as described in the *Coordination Responsibilities* section of the SOL Methodology, it is the specific responsibility of TOPs to agree on the System Voltage Limits for buses that connect to adjacent TOPs. If the TOPs cannot agree, the most limiting System Voltage Limits will apply as a default. If this default poses an unfounded restriction or a reliability issue for the interconnecting TOPs, the TOPs must collaborate with Peak to reach a resolution.

4. System Voltage Limits must provide for reliable operations. If a TOP provides System Voltage Limits that Peak determines to be detrimental to the reliable operation of the BES, Peak may request a technical justification for the use of such limits and may prescribe System Voltage Limits.

5. System Voltage Limits must respect voltage limits identified in Nuclear Plant Interface Requirements.

6. Low System Voltage Limits must not be lower than a value that triggers operation of UVLS.

7. Normal High System Voltage Limits must respect the voltage ratings of the connected equipment.

8. Emergency High System Voltage Limits must respect Protection Systems that trip BES Facilities in response to high voltages.

9. For any applicable substation bus, System Voltage Limits must include the following:

    a. **A Normal Low System Voltage Limit** – the low voltage limit that is used and monitored for actual/pre-Contingency operations. An actual/pre-Contingency voltage below a Normal Low System Voltage Limit is an SOL exceedance and indicates that TOPs need to take action, if mitigation options exist, to increase the actual/pre-Contingency voltage above the limit.

    b. **An Emergency Low System Voltage Limit** – the low voltage limit that is used for emergency operations and is otherwise monitored for the post-Contingency state. A calculated post-Contingency voltage below an Emergency Low System Voltage Limit is an SOL Exceedance and requires pre-Contingency action, if mitigation options exist, to increase the calculated post-Contingency voltage above the limit.

    c. **A Normal High System Voltage Limit** – the high voltage limit that, if exceeded in actual/pre-Contingency operations, represents an unacceptably high voltage (as determined by the TOP) at the bus. Normal High System

Voltage Limits are used and monitored for actual/pre-Contingency operations. When actual/pre-Contingency voltage is above a Normal High System Voltage Limit, an SOL is being exceeded, and TOPs need to take action, if mitigation options exist, to decrease the actual/pre-Contingency voltage below the limit.

d. **An Emergency High System Voltage Limit** –the high voltage limit that is used for emergency operations and is otherwise monitored for the post-Contingency state. Emergency High System Voltage Limits should be established such that they are actionable by the TOP for the calculated post-Contingency state, i.e., when Real-time Assessments indicate that an Emergency High System Voltage Limit is exceeded in the calculated post-Contingency state, the indication results in pre-Contingent System Operator action to reduce calculated post-Contingency voltage to within the limit. A calculated post-Contingency voltage above an Emergency High System Voltage Limit is an SOL Exceedance and requires pre-Contingency action, if mitigation options exist, to decrease the calculated post-Contingency voltage below the limit.

Table 2 – System Voltage Limits below summarizes System Voltage Limit monitoring:

Normal High/Low	Emergency High/Low
<u>Real-time:</u> A. Monitored in SCADA or State Estimation for actual exceedance <u>Study:</u> B. Monitored for pre-Contingency exceedance	<u>Real-time</u>: • Monitored in SCADA or State Estimation for actual exceedance • Monitored in RTCA (or equivalent) for calculated post-Contingency exceedance <u>Study:</u> • Monitored for pre-Contingency exceedance • Monitored in Contingency Analysis for calculated post-Contingency exceedance

Table 2 – System Voltage Limits

Communication of System Voltage Limits

10. TOPs shall communicate System Voltage Limits according to the method described in the RC instructions. The TOP shall communicate any changes in System Voltage

Limits (made in response to actual or expected system conditions) to the RC and to impacted TOPs.

Stability Limitations

Transient stability limits and voltage stability limitations are SOLs. Transient and voltage instability in Real-time operations is generally assessed in one of two ways, either of which is acceptable:

- Through the use of advanced Real-time applications that assess the system's response to simulated Contingency events, which may include system transfer scenarios.

- Through the use of predetermined limits established in offline studies which, if operated within, are expected to result in acceptable stability performance in response to the simulated Contingency event.

If method described in the second bullet is used, it is the responsibility of the TOP to determine when it is appropriate to use stability limitations established in previous studies, or whether expected system conditions warrant performing new studies to revise those stability limitations used in Real-time operations.

Both methods must meet the performance criteria specified in the SOL Methodology.

When interface/cutplane stability limitations are established, they should be established in a manner that most accurately and directly addresses the instability risk, for example a stability limitation should be established on an interface/cutplane that most accurately and directly monitors the instability risk that may not coincide with defined WECC Paths. Neither historical presumptions/practices regarding system monitoring nor commercial/contractual arrangements should influence where stability limitations are most accurately established and monitored for reliability.

<u>Transient Analysis Methodology</u>

1. It is up to the TOP and/or the RC to determine if and what types of operational transient studies are required for a given season, planned outage or operational scenario. For example, if a TOP or the RC determines, based on experience, engineering judgment and knowledge of the system, that a planned transmission or generation outage might pose a risk of transient instability for the next worst single P1 Contingency or credible MC, the TOP should perform the appropriate transient analyses to identify those risks.

2. If an allowable UVLS, UFLS or a RAS is relied upon to address a transient instability phenomenon, the transient analysis must include the actions of these schemes to ensure that the schemes adequately address the reliability issues. Associated study reports or Operating Plans must include a description of the actions and timing of these schemes.

3. Transient studies must model applicable Facility outages that are planned for the period of the study and must use appropriate load levels.

4. Available peak and off-peak (light load) loading conditions should be screened for the period under study to determine the conditions under which instabilities occur. The TOP and/or the RC may run studies on only those specific set of conditions for subsequent studies. The intent is to do due diligence to identify instability risks for both expected heavy-load conditions and expected light-load conditions.

5. Single P1 Contingencies shall include the more severe or impactful of single line-to-ground Faults or three-phase Faults as determined by the TOP or RC.

6. Three-phase and single line-to-ground Faults will be simulated at no more than 10 percent from each point of connection with bus, or the more severe of the high or low side of an autotransformer.

7. The Fault duration applied should be based on the total known Fault clearing times or as specified in the corresponding planning studies for the applicable voltage level. For credible MC events, the appropriate clearing times must be modeled.

8. Transient analysis must extend for at least 10 seconds following the initiating event, or longer if swings are not damped.

9. The dynamics parameter file used for transient studies shall be based upon the approved WECC dynamics file with the following additions: a generic mho distance relay model that is set for all Facilities 100kV and above with zone 1 setting of 80 percent, a zone 2 setting of 120 percent with a 24 cycle delay and a zone 3 setting of 140 percent with a 36 cycle delay shall be included in the dynamics model file. These relays shall be set to “non-tripping” mode. Any actions by relay models during a simulation must be investigated and, if warranted, specific relay models and settings applied. Entities may modify the generic step distance relay settings specified above to reflect their protection philosophy.

10. A generic voltage and frequency ride-through relay model should be installed on all generators at the point of interconnection that models the voltage and frequency ride-through capabilities specified in PRC-024-2. This generic relay may be set to “non-tripping” but any actions by the relay must be checked against the unit actual

tripping settings and the appropriate actions taken. For generators for which the GO has provided exceptions to the requirements of PRC-024-3 under requirement R3, the specific tripping points must be modeled and any appropriate actions taken.

11. The buses monitored for transient system performance should be determined based on engineering judgment.

Transient Analysis Performance Requirements

Transient system performance requirements are indicated in **Table 3** – Transient System Performance Requirements below.

Transient System Performance	**Required for Single P1 Contingencies**	**Required for Credible Multiple Contingencies**
The system must demonstrate positive damping. The system is considered to demonstrate acceptable positive damping if the damping ratio of the power system oscillations is 3% or greater. The signals used generally include power angle, voltage and/or frequency. An example of damping ratio calculation is provided in Appendix B. There may be instances where it is prudent to allow for a damping ratio less than 3%. In such cases, studies must demonstrate that the damping provides for an acceptable level of reliability, and the use of the lower damping threshold must be reviewed and accepted by impacted TOPs and by the RC.	Yes	Yes
The BES must remain transiently stable, and must not Cascade or experience uncontrolled separation as described in the SOL Methodology. System frequency in the interconnected system as a whole must not trigger UFLS. Any controlled islands formed must remain stable.	Yes	Yes
Transient voltage or frequency dips and settling points shall not violate in magnitude and duration: 1. Generator ride-through capabilities as specified by PRC-024-2; no BES generating unit shall pull out of synchronism (or trip) in response to transient system performance; UFLS shall not be triggered. 2. Nuclear plant interface requirements.	Yes	No

3. Known BES equipment trip or failure levels, e.g. surge arrestors, transformer saturation levels, generator over-excitation.		
General Notes: 1. UVLS or other automatic mitigation actions are permitted as specified within Peak Reliability's SOL/IROL methodology. 2. A generator being disconnected from the system by Fault clearing action or by a RAS is not considered losing synchronism. Additionally, small (<25 MW) non-BES generators that may trip are not considered as losing synchronism. 3. If known BES equipment trip settings are exceeded, the appropriate actions must be modeled in the simulations. 4. For generators that the GO or NPIR has identified as not being able to meet the PRC-024-2 requirements, either the unit must be tripped, or the Point of Interconnection (POI) frequency verified against the unit established trip values and the appropriate action taken.		

Table 3 – Transient System Performance Requirements

Establishment of Transient Stability Limits

12. Transient stability limits are established to meet the transient system performance requirements in Table 3 – Transient System Performance Requirements.

13. Transient stability limits do not include operating margins. Operating margins are specified in the corresponding Operating Plans.

14. If TOP or RC transient analyses are technically accurate yet the results of the studies do not agree (i.e., if one TOP's analysis results differ from another TOP's analysis results, or if a TOP's analysis results differ from the RC's analysis results), then the most limiting analysis results are used as a default if the differences cannot be worked out.

Communication of Transient Stability Limits

15. When TOP studies indicate the presence of transient instability risks (whether contained or uncontained), the TOP shall communicate the study results to Peak and to impacted TOPs for further review. This communication should occur in a timely manner to allow for proper coordination and preparation prior to Real-time operations.

16. TOPs shall communicate transient stability limits according to the method described in the RC instructions.

Post-Transient Analysis Methodology

The post-transient period is the timeframe after any initial swings and transient effects of a disturbance are over, but prior to AGC or operator actions. Post-transient analysis is performed through a governor power flow study.

17. The starting point of the analysis is the system condition with the event modeled and taking into account the effects of allowable automatic actions as described in the *Allowed Uses of Automatic Mitigation Schemes in the Operations Horizon* section of the SOL Methodology, e.g., UVLS, UFLS and RAS actions.

18. Impacts of the composite load model as observed in transient analyses shall not be included in the post-transient analysis since the restoration of this load is not under the control of operating personnel. For example, a transient study indicates that a Contingency results in load being lost due to composite load model behavior in the transient timeframe. When performing a subsequent post-transient analysis of that Contingency, the load shall not be reduced by the amount of expected loss that occurred in the transient analysis in response to the composite load model.

19. The Contingencies being studied shall be run with the area interchange controls and phase shifters controls disabled. Tap-Changer Under Load (TCUL), shunt capacitors and Static Var Compensators (SVC) that are automatically controlled may be allowed to switch provided the automatic control settings are accurately modeled and the devices will switch within 20 seconds or less[11]. Generators and SVCs shall be set to regulate the terminal bus voltage unless reactive droop compensation is explicitly modeled or SVC control signals are received from a remote bus.

20. RAS actions shall be accounted for by taking the same specific actions as the RAS, i.e., the same generators will be tripped and the same loads disconnected. Loss of generation shall be accounted for in the power flow by scaling up the generation in the interconnected system, with Pmax limits imposed, excluding negative generators and negative loads. Any increase or decrease in generation shall be done on the weighted MW margin (up/down range) or the closest equivalent based on the

[11] The 20 second reaction time for switchable reactive devices is to ensure coordination with generator Maximum Excitation Limiter (OEL) settings. Typical OEL's will begin to reduce a generator's reactive output to safe operating levels within a 20-second window. Reference IEEE Recommended Practice for Excitation System Models for Power System Stability Studies, IEEE Std. 421.5-2005 (Revision of IEEE Std. 421.5-1992), 2006, pp. 0_1–85.

program used. Alternatively, units may respond in proportion to the nameplate ratings. Base-loaded units must be blocked from responding.

Establishment of Voltage Stability Limits

21. Voltage stability limits are SOLs. Voltage stability limits are established using transient (for fast voltage collapse risks) and post-transient analysis techniques. One representation of a voltage stability limit is the maximum pre-Contingency megawatt power transfer for which a post-Contingency solution can be achieved for the limiting (critical) Contingency (i.e., the last good solution established the voltage stability limit). P-V and V-Q analysis techniques are used as necessary for the determination of voltage stability limits. While megawatt power transfer represents one approach for defining a voltage stability limit, other units of measure (such as VAR limits) may be used, provided this approach is coordinated between the TOP and the RC. Reference **Figure 3 – Sample P-V Curve** as an example of a MW power transfer approach to defining a voltage stability limit.

22. The voltage stability limit does not include operating margins. Operating margins are specified in the corresponding Operating Plans.

23. If TOP or RC post-transient analyses are technically accurate yet the results of the studies do not agree (i.e., if one TOP's analysis results differ from another TOP's analysis results, or if a TOP's analysis results differ from the RC's analysis results), then the most limiting analysis results are used as a default if the differences cannot be worked out.

Reference Figure 3 – Sample P-V Curve below for an example of a PV curve for determining voltage stability limits.

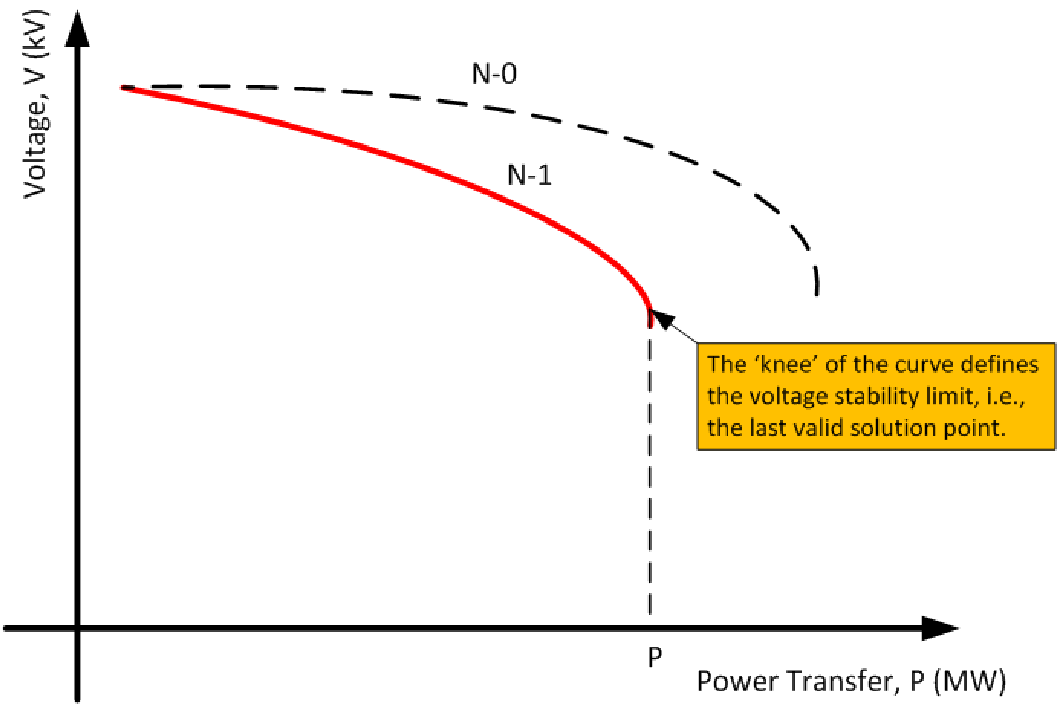


Figure 3 – Sample P-V Curve

<u>Communication of Voltage Stability Limits</u>

24. When TOP studies indicate the presence of voltage instability risks (whether contained or uncontained), the TOP shall communicate the study results to Peak and to impacted TOPs for further review. This communication should occur in a timely manner to allow for proper coordination and preparation prior to Real-time operations.

25. Voltage stability limits shall be communicated per the posted RC instructions.

R. System Stressing Methodology

The objective of this system stressing methodology is to either identify instability risks or to rule them out for all practical purposes for Operating Horizon studies.

- If instability risks are identified, there is a need to establish stability limitations (which may include implementing Real-time stability limit calculators) and/or to establish Operating Plans to address those instability risks.
- If instability risks are ruled out for expected operating conditions, then subsequent reliability analyses might exclude stability analyses for the Operating Horizon, provided system conditions are comparable to those represented in prior studies.

If instability risks can be ruled out for expected operating conditions, then subsequent reliability analyses – i.e., Operational Planning Analyses (OPA) and Real-time Assessments (RTA) – using steady state Contingency analysis of actual or expected conditions, are sufficient to confirm that the system can be reliably operated within acceptable pre- and post-Contingency performance requirements with regard to Facility Ratings and System Voltage Limits.

Differing Objectives for System Stressing

Transfer analyses that stress the power system are performed to determine the pre- and post-Contingency reliability issues that can be encountered as transfers increase into a load area or across a transmission interface. How far the system is stressed as part of transfer analyses depends on the purposes and objectives of the analysis.

If the purpose of the transfer analyses is to determine Transfer Capability (TC) or TTC, the system generally needs to be stressed only to the point where a reliability limitation is encountered (with an applicable margin). In principle, TCs are generally determined by stressing the system until either of the following reliability constraints is encountered:

- In the pre-Contingency state, flows exceed normal Facility Ratings, voltages fall outside normal System Voltage Limits or instability occurs (i.e., the system is stressed to the point of unacceptable pre-Contingency performance with regard to thermal, steady-state voltage or instability constraints).
- In the post-Contingency state, flows exceed emergency Facility Ratings, voltages fall outside emergency System Voltage Limits or instability occurs (i.e., the system is stressed to the point of unacceptable post-Contingency performance with regard to thermal, steady-state voltage or instability constraints).

Most Paths in WECC are either thermally limited or steady-state voltage limited, as opposed to transient stability or voltage stability limited. For these Paths, transfer analyses have shown that the first reliability limitations encountered are post-Contingency exceedances of emergency Facility Ratings or emergency System Voltage Limits. For example, when stressing a Path, transfer analyses indicate that at a certain level of transfer, a single P1 Contingency results in exceedance of another Facility's emergency Facility Rating. Similarly, these transfer analyses may indicate that at a certain level of transfer, a P1 Contingency results in voltage at a bus falling outside its emergency System Voltage Limit.

While TC studies do not require that the system be stressed appreciably beyond the point of encountering the first reliability limitation, the same cannot be said for transfer analyses that are performed for purposes of determining whether instability risks exist for expected system conditions. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a first reliability limitation, it may be necessary to identify where subsequent operation may approach a point of instability.

To adequately determine whether instability risks exist for expected system conditions for a given transmission interface or load area, the system must be stressed beyond the point where thermal or voltage limitations are encountered. The question is: how far does the system need to be stressed before instability risks can be ruled out for all practical purposes?

Note that transfer analyses for purposes of determining TC or TTC are outside the scope of the SOL Methodology.

Stressing Requirements to Determine Instability Risks

Transient instability, voltage instability or Cascading may occur in response to a single P1 Contingency or a credible MC under stressed conditions. Engineers perform studies that evaluate the system under stressed conditions to identify these risks. As was stated in the introduction of this section, the objective of this system stressing methodology is to either identify instability risks or to rule them out. Under this methodology, it is the primary responsibility of the TOP to identify or rule out instability risks and to determine how far transmission interfaces and load areas should be stressed to accomplish this intended objective. System stressing requirements depend on several factors and therefore cannot be specified in a one-size-fits-all approach. While the system should be stressed far enough to accomplish the intended objective, the expectation of this methodology is to stress the system up to – and slightly beyond – reasonable maximum stressed conditions. It is not the intent of this methodology for TOPs to stress the system unrealistically or to stress the system to levels appreciably beyond those that are practically or realistically achievable.

This methodology should be applied to applicable studies performed in the Operations Horizon including, at a minimum, seasonal planning studies and outage coordination studies as determined to be necessary by the TOP. While the stressing methodology may optionally be applied to Operational Planning Analyses and Real-time Assessments, it is not required. For transmission interfaces that span multiple TOP Areas, the TOPs that operate the Facilities on the interface are expected to coordinate to determine appropriate levels of stressing necessary to identify or rule out instability risks. TOPs are expected to document stressing levels performed in operations planning studies and to communicate these levels and the results of these analyses to the RC when instability or Cascading is identified.

The following considerations should be used as a guideline to determine appropriate levels of system stressing:

1. Source area is exhausted – When stressing a transmission interface, in some cases it is possible to maximize the source area in the simulation before any reliability issues (thermal, voltage or instability) are encountered. If the source area is exhausted in simulations, then it can be concluded that there is no way to realistically simulate any additional transfers. Load should not be scaled unrealistically as part of increasing exports. For example, when simulating exports, it may be unreasonable to scale load down by 50 percent of its expected value to simulate exports. The TOP is expected to determine reasonable uses of load as a mechanism for simulating exports.

2. If the source is maximized before either the nose of a PV or VQ curve is reached, before transient instability occurs, or before Cascading takes place (per the Cascading test outlined in the SOL Methodology), then it can be concluded that no instability or Cascading risks practically exist for the interface and there is no reliability need to establish stability limitations for the interface or load area. Different methodologies will be used (as further discussed below) for transmission interfaces where source generation cannot be maximized in the simulation.

3. Sink area is depleted – When stressing an interface into a load area, it is possible to de-commit or reduce the output of all generators internal to the load area (i.e., serve the load with ~100 percent imports) before any pre- or post-Contingency reliability issues (thermal, voltage or instability) are encountered. Entities should model the expected minimum generation commitment in the load sink area at the expected maximum import level and simulate largest generation Contingency as part of simulations. If the generation internal to the sink load area is decreased to the minimum generation commitment level and the sink's load is modeled at reasonably expected maximum conditions, then it can be concluded that there is no practical way to simulate any additional imports into the area. Load should not be scaled unrealistically as part of increasing imports. For example, when simulating imports, it may be unreasonable to scale load in the sink area up by 150 percent of its expected

value to simulate imports. The TOP is expected to determine reasonable uses of load as a mechanism for simulating imports.

4. If the generation internal to the sink load area is depleted and load is maximized either before the nose of a PV or VQ curve is reached, before transient instability occurs, or before Cascading takes place (per the Cascading test outlined in the SOL Methodology), then it can be concluded that no stability limits or Cascading risks practically exist for the load area and there is no reliability need to establish a stability limit for the load area.

5. It may be possible to simulate flow on an interface or into a load area to levels that are unrealistic for operations. While it is expected that the system be stressed beyond the historical 2.5-to-5 percent levels for identifying or ruling out instability risks, the TOP, in collaboration with neighboring TOPs as necessary, are expected to determine reasonable maximum stressing conditions to identify or rule out instability risks. If the system is stressed to levels just beyond those determined by impacted TOPs as being reasonably expected maximums and no instability occurs in the simulations, or simulated flows do not reach the level where potential Cascading can occur, then it can be concluded that no instability or Cascading risks practically exist for the interface or load area and thus there is no reliability need for establishing stability limits or stability-related Operating Plans.

6. It is possible to stress the system to a point where potential Cascading is encountered. Cascading tests should be performed consistent with the Instability, *Cascading, Uncontrolled Separation and IROLs* section of the SOL Methodology. This analysis assumes that pre- and post-Contingency flows are below applicable Facility Ratings prior to the transfer analysis.

7. System stressing studies may result in transient instability or the nose of a PV or VQ curve being reached[12] either under pre-Contingency conditions or upon occurrence of a single P1 Contingency or credible MC. This condition indicates the presence of an instability risk and thus the need to establish a transient or voltage stability limit or to otherwise manage the instability risk via an Operating Plan.

8. Any instability or Cascading risks identified as a result of applying this system stressing methodology must be communicated to the RC. For identified Cascading or

[12] If the nose is not reached and different solving techniques do not result in a solution, then the last solved solution determines the stability limit.

instability risks, the RC will collaborate with the TOP(s) in the establishment of stability limitations and Operating Plans to mitigate these risks.

S. Instability, Cascading, Uncontrolled Separation and IROLs

IROLs are distinguished from SOLs in a few ways:

1. An IROL is a subset of SOLs that is associated with instability, uncontrolled separation or Cascading. SOLs include a broader set of limitations including Facility Ratings and System Voltage Limits, and certain non-IROL stability limitations.
2. IROL exceedance is associated with a heightened risk to the reliability of the BES. The reliability consequences associated with exceeding an IROL are more severe and adversely impactful than the reliability consequences associated with exceeding an SOL that is not an IROL. This distinction is seen in the following:
    a. Per the NERC Reliability Standards, an IROL carries with it a required mitigation time, the IROL T_V, which can be no longer than 30 minutes. When an IROL is exceeded, the NERC Reliability Standards require that the IROL be mitigated within the IROL T_V.
    b. While the NERC Reliability Standards require that any SOL exceedance identified in Operational Planning Analyses must have an associated Operating Plan, the standards require that IROLs have an Operating Plan/Process/Procedure that contains steps up to and including load shedding to prevent exceeding the IROL.
3. IROLs should be established such that when an IROL is exceeded, the Interconnection has entered into an N-1 or credible N-2 insecure state, i.e., the most limiting single P1 Contingency or credible MC could result in instability, uncontrolled separation or Cascading outages that adversely impact the reliability of the BES.

An IROL is defined in the NERC Glossary of Terms as:

A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages[13] that adversely impact the reliability of the Bulk Electric System.

[13] On September 13, 2012, FERC issued an Order approving NERC's request to modify the reference to "Cascading Outages" to "Cascading outages" within the definition of IROL due to the fact that the definition of "Cascading Outages" was previously remanded by FERC.

By definition, IROLs are SOLs that could lead to any of the following three operational phenomena:

- Instability,
- Uncontrolled separation, or
- Cascading outages

It is observed that each of these three phenomena can be interpreted to have very different meanings and applications, which can lead to inconsistencies in IROL establishment. The following sections provide a brief characterization of each of the three phenomena with the objective of providing for more consistency in the establishment of IROLs in the Operations Horizon.

Instability

A major challenge the industry faces is with the word "instability" in the IROL definition. Per the existing definition, an IROL is an SOL which, if exceeded, could result in instability. However there are many forms of instability, each with a wide spectrum of reliability impacts – from little to no impact, such as losing a unit due to "instability," all the way to major and devastating impact, such as losing a major portion of the BES due to instability.

It is recognized that not all types of instability pose the same degree of risk to the reliability of the BES. At the same time, it also is recognized that regardless of the type of instability, it is critical that studies/assessment determine how – or if – the instability will be contained, and to understand the impact that the instability may have on the BES.

Accordingly, transient or voltage instability that cannot be demonstrated through studies to be confined to a localized, contained area of the BES effectively has a critical impact on the operation of the Interconnection, and therefore warrants establishment of an IROL.

Uncontrolled Separation

Uncontrolled separation (which includes uncontrolled islanding) occurs when studies indicate that a Contingency is expected to result in rotor angle instability or to trigger relay action which causes the system to break apart into major islands in an unintended (non-deliberate) manner. The determination of uncontrolled separation takes into consideration transient instability phenomena and relay actions that cause islands to form.

It is recognized that transient instability may result in the loss of small pockets of generation and load, or radially connected subsystems that do not warrant establishment of an IROL and do not constitute a violation of the credible MC performance requirements stated in section entitled *Performance Requirements for Always Credible and Applicable Conditionally Credible*

MCs. In such scenarios, the loss of a unit (or group of units) may have little to no impact on the reliable operation of the interconnected system.

Uncontrolled separation can be understood by comparing it to the following description of controlled separation:

4. Controlled separation is achieved when there is an automatic scheme that exists and is specifically designed for the purposes of:
    a. Intentionally separating the system.
        i. Note that such schemes may be accompanied by generation drop schemes or UFLS that are designed to shed load or drop generation to achieve generation/load equilibrium upon occurrence of the controlled separation.
    b. Intentionally mitigating known separation conditions.
        i. I.e., a scheme that is designed specifically to drop load or generation to achieve generation/load equilibrium upon a known Contingency event that poses a separation risk.
5. Post-Contingency islanding due to transmission configuration does not constitute uncontrolled separation.
    a. There are occasions where planned or forced transmission outages can render the transmission system as being configured in a manner where the next Contingency (single P1 Contingency or credible MC) can result in the creation of an island. Operators are made aware of these scenarios through outage studies, OPAs and/or RTAs, and are expected to have Operating Plans that would address the condition in a reliable manner. Such conditions should consider the associated risks and mitigation mechanisms available; however, they are excluded from the scope of uncontrolled separation for the purposes of IROL establishment.
6. Examples of controlled separation:
    a. Example 1: A RAS is designed specifically to break the system into islands in an intentional and controlled manner in response to a specific Contingency event(s). Supporting generation drop and/or UFLS are in place to achieve load/generation equilibrium.
    b. Example 2: A UFLS is specifically designed to address a known condition where a credible MC is expected to create an island condition.

Cascading

Cascading is defined in the NERC Glossary of Terms as:

> *The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.*

Cascading can occur when studies indicate that a Contingency results in severe loading on a Facility, triggering a chain reaction of Facility disconnections by relay action, equipment failure or forced immediate manual disconnection of the Facility (for example, due to line sag or public safety concerns). Per the definition, when Cascading occurs, the electric service interruption cannot be restrained from sequentially spreading beyond an area pre-determined by studies.

Instability can cause Cascading. When Cascading is a response to instability, the Cascading will be addressed via a stability-related IROL.

Cascading test – If powerflow studies indicate that the successive tripping of Facilities stops before the case diverges, then by definition, the phenomenon is not considered to be Cascading, because the studies have effectively defined an "area predetermined by studies." However, if the system collapses during the Cascading test, the area cannot be "predetermined by studies," and therefore it is concluded that the extent of successive tripping of elements cannot be determined. When this is the case, an IROL is warranted.

Powerflow Cascading Test:

7. Run Contingency analysis and flag single P1 Contingencies and credible MCs that result in post-Contingency loading in excess of the lower of:
    a. The Facility(ies)'s trip setting
    b. 125 percent of the highest Emergency Rating
8. For each flagged Contingency, open both the contingent element(s) that cause(s) the post-Contingency loading and all consequent Facilities that overload in excess of (7) (a) or (b) above. Run powerflow.
9. Repeat step (8) for any newly overloaded Facility(ies) in excess of (7) (a) or (b) above. Continue with this process until no more Facilities are removed from service or until the powerflow solution diverges.
10. If the subsequent tripping of Facilities stops prior to case divergence, then it can be concluded that the area of impact is predetermined by studies, and thus Cascading

does not occur. If the case diverges during the Cascading test, then it can be concluded that Cascading occurs.

T. IROL Establishment

The SOL Methodology considers IROLs to be limits that are identified one or more days prior to Real-time[14]. IROLs will generally be identified and established as part of seasonal planning analyses, through special studies and through the IRO-017-1 Outage Coordination Process. While it is possible to identify an IROL in the Operational Planning Analysis timeframe, this should be a rare occurrence since the IRO-017-1 Outage Coordination Process should identify reliability issues prior to the OPA timeframe, providing for cancellation of outages that pose the significant reliability risk.

An IROL is a limit, not a condition. The IROL term is often erroneously used to represent a condition. It is sometimes said that “instability is an IROL” or “Cascading is an IROL.” Instability, Cascading or uncontrolled separation are phenomena, they are not an IROL. An IROL is a limit put in place to prevent instability, Cascading or uncontrolled separation from occurring.

When the SOL Methodology uses the term IROL, it is used in the context of the IROL being identified in studies performed one or more days prior to Real-time. Per the SOL Methodology, IROLs are always pre-identified through studies. However, it is acknowledged that unanticipated Real-time events can render the BES in a state where Real-time Assessments indicate that the system is not secure for the next single P1 Contingency or credible MC. Such N-1 or N-2 insecure conditions are addressed through Operating Plans outside of the auspices of an IROL; however, these conditions are treated with the same level of urgency as IROLs. This approach is consistent with the notion that an IROL is a limit and not a condition. When such unanticipated conditions unexpectedly occur in Real-time operations, Peak Reliability Coordinator System Operators are expected to bring the system to an N-1 or credible N-2 secure state within 30 minutes, in accordance with internal Operating Plans.

The RC is responsible for declaring IROLs. TOPs are not responsible for declaring IROLs; however, TOPs are responsible for communicating and collaborating with the RC when studies (seasonal studies, special studies, outage studies or OPAs) result in instability (whether contained or uncontained), Cascading or uncontrolled separation as described in the

[14] While the value of the identified IROL can be calculated in Real-time, the identification of the IROL occurs one or more days prior to Real-time.

SOL Methodology. Upon this communication, the RC then collaborates with the TOP to determine if an IROL needs to be established to address these risks.

Long-Term IROLs versus Planned Outage Condition IROLs

The SOL Methodology distinguishes long-term IROLs from Planned Outage Condition IROLs.

Long-Term IROLs

While long-term IROLs may only pose a risk under certain loading conditions or generation dispatch conditions, they are not a function of planned outages. Long-term IROLs may be in effect at all times, or they may be in effect during certain specified system conditions unique to that IROL; however, they generally remain as identified IROLs until physical system reinforcements are made to address the associated risk of instability, uncontrolled separation or Cascading. Long-term IROLs are established to prevent instability, uncontrolled separation or Cascading as described in the SOL Methodology for:

1. Single P1 Contingencies
2. Credible MCs
3. N-1-1 and N-1-2 operations starting with an “all transmission Facilities in service” case, without system adjustments

Long-term IROLs are identified through seasonal planning studies and through special studies conducted by the RC, by the TOP(s) or by the RC in collaboration with the TOP(s). However, it is the RC that ultimately declares IROLs for use in the Operations Horizon. Relevant information for IROL identification can be gleaned from several sources including, for example, prior operational experiences/events and planning studies performed in association with the NERC TPL standards, and from planning studies performed in association with FAC-010-3 and corresponding requirements applicable to PCs and TPs in FAC-014-2.

Long-Term IROLs for N-1-1 and N-1-2 Operations (Referencing Item 3 Above)

Application:

4. Addresses known N-1-1 and N-1-2 risks that could result in instability, Cascading or uncontrolled separation as described in the SOL Methodology
5. Applicable to an “all transmission Facilities in service” starting point case(s)
6. Addresses N-1-1 and N-1-2 operations (without system adjustments) where:
    a. “N” is an “all transmission Facilities in service” case(s)
    b. The first “-1” is a forced outage or a single P1 Contingency event

c. The second “-1” is the next worst single P1 Contingency, or the “-2” is the next worst Always Credible MC

7. Long-term IROLs are not established for N-2-1, or N-2-2 conditions, due to the low probability of occurrence of the first “-2” Contingency event.

Purpose:

Long-term N-1-1 and N-1-2 IROLs are intended to pre-identify and prepare for the following scenario:

8. The system is being operated in a “normal” mode. The system demonstrates acceptable system performance for the pre- and Post-Contingency state.

9. A single P1 Contingency or a forced/urgent outage of a single Facility occurs.

10. The system is now in a new and different state before system adjustments can be made.

11. Based on this new state, the next single P1 Contingency or Always Credible MC could result in instability, Cascading or uncontrolled separation as described in the SOL Methodology, and thus the system is now in an N-1 (or credible N-2) insecure state.

Rationale for Long-Term N-1-1 and N-1-2 IROLs:

N-1-1 and N-1-2 IROLs are identified and established to provide System Operators an awareness of instances where a single P1 Contingency or a forced/urgent outage on a single Facility is pre-determined by studies to render the system in a state where the next single P1 Contingency or Always Credible MC can result in instability, uncontrolled separation or Cascading as described in the SOL Methodology.

12. Given an initial condition state of “all transmission Facilities in service” in a normal mode of operation, if a single P1 Contingency or a forced/urgent single Facility outage causes engineers/operators to re-position the system with the specific objective of preventing instability, Cascading or uncontrolled separation as described in the SOL Methodology for the next worst single P1 Contingency or Always Credible MC, then the system is in an N-1 or N-2 insecure state until those system adjustments can be made to transition the system to an N-1 or N-2 secure state.

13. When N-1-1 or N-1-2 studies indicate that the first “-1” renders the system in an N-1 or N-2 insecure state where the next single P1 Contingency or Always Credible MC can result in instability, Cascading or uncontrolled separation as described in the SOL Methodology, a long-term IROL is warranted.. This IROL would become

effective when the first "-1" event occurs and would prevent the next Single P1 Contingency or Always Credible MC from resulting in instability, Cascading or uncontrolled separation as described in the SOL Methodology. Such IROLs will be in effect only upon a forced/urgent outage or Contingency of the first "-1" Facility.

14. For such predetermined N-1-1 and N-1-2 IROLs, it is acceptable to operate the system such that the first "-1" Contingency will result in exceeding the IROL, provided that System Operators know that they are able to mitigate the IROL within the IROL T_V after the "-1" Contingency event occurs. If System Operators are not able to mitigate the IROL exceedance within the IROL T_V after the first "-1" Contingency event occurs, then pre-Contingency actions must be taken such that System Operators are able to mitigate the IROL exceedance within the IROL T_V after the first "-1" Contingency occurs[15].

Process for Identifying Long-Term IROLs for N-1-1 and N-1-2 Conditions:

Long-term N-1-1 and N-1-2 IROLs are identified using transient analysis and/or post-transient analysis techniques described in the SOL Methodology. The following analysis process should be used to determine if an N-1-1 or an N-1-2 IROL should be established:

15. N-1-1 and N-1-2 analysis assumes an "all transmission Facilities in service" initial condition. Assessments are based on reasonable max stressing conditions and historical flows. Reference the system stressing methodology.

16. The first single P1 Contingency is simulated.

17. No system adjustments are made other than allowable automatic action such as governor response, automatic capacitor switching, RAS, etc.

18. The next worst single P1 Contingency or Always Credible MC is then simulated to determine if the Contingency results in instability, Cascading or uncontrolled separation as described in the SOL Methodology. The analysis of this next worst single P1 Contingency or Always Credible MC event should account for allowable automatic schemes that are designed to address these Contingencies.

19. If the next single P1 Contingency or Always Credible MC results in instability, Cascading or uncontrolled separation as described in the SOL Methodology, then the condition indicates that system adjustments must be made after the first "-1"

[15] Reference FERC Order 705 paragraph 125, which states, *"Therefore, the Commission proposed to accept the definition of IROL Tv with the understanding that the only time it is acceptable to violate an IROL is in the limited time after a contingency has occurred and the operators are taking action to eliminate the violation."*

Contingency, but before the second Contingency, to prevent the instability, Cascading or uncontrolled separation as described in the SOL Methodology from occurring. This fact points to the presence of an IROL that would become effective upon a forced/urgent outage or Contingency of the first “-1” Facility.

20. Once these risks are identified, the N-1-1 and N-1-2 studies should then identify system adjustments that must be made (and the timing associated with these adjustments) after the first “-1” Contingency event to prevent the second Contingency event from resulting in instability, Cascading or uncontrolled separation as described in the SOL Methodology. These system adjustments should be taken into consideration when developing the IROL Operating Plan. IROLs must be determined that can be applied upon a forced/urgent outage or a Contingency of the first “-1” Facility. These IROLs can be pre-established values, or they can be calculated in Real-time.

21. The lower of the relay setting or 125 percent Cascading test as described in the SOL Methodology applies for the determination of Cascading.

22. For identified IROLs for N-1-1 and N-1-2 conditions, Real-time N-1-1 and N-1-2 analyses/calculations are prudent to provide System Operators awareness as to whether that IROL would be expected to be exceeded upon a Contingency or a forced/urgent outage of the first “N-1” Facility.

Long-Term N-1-1 Instability IROL Example:

Studies show that the loss of Facility X is expected to render the system in a position where a subsequent Contingency on Facility Y would result in wide-area voltage instability, i.e., that the loss of line X would render the system in an N-1 insecure state for Contingency Y. An IROL is established to prevent the loss of Facility X, followed by a Contingency of Facility Y, resulting in wide-area voltage instability.

23. The IROL exists on the monitored interface appropriate for determining wide-area voltage instability for the loss of Facility Y.

24. For this example, the IROL is monitored as the maximum MW flow (the last good solution) on the monitored interface above which the subsequent loss of Facility Y results in wide-area voltage instability.

25. The IROL becomes effective when Facility X experiences a forced/urgent outage. The IROL is not in effect unless there is a forced/urgent outage or Contingency of Facility X.

26. The IROL is exceeded when Facility X experiences a forced/urgent outage and subsequent Real-time Assessments indicate that the flow on the monitored interface is above the value where the loss of Facility Y results in wide-area voltage instability. The IROL can be a pre-established value, or it can be calculated in Real-time.

Planned Outage Condition (POC) IROLs

POC IROLs are established to prevent instability, Cascading or uncontrolled separation as described in the SOL Methodology during planned outage conditions. POC IROLs are temporary in nature and do not apply when the planned outage is not in effect. Additionally, POC IROLs are established for the outage conditions as expected system conditions warrant. For example, a planned outage for Facility XYZ during the month of August when loads are high may require a POC IROL to be established for the duration of that outage; however, an outage on that same Facility in November when loads are low may not require a POC IROL to be established.

POC IROLs are established to prevent instability, uncontrolled separation or Cascading as described in the SOL Methodology for:

- Single P1 Contingencies
- Credible MCs

POC IROLs are generally not established to address N-1-1 or N-1-2 operations during planned outages; however, TOPs and the RC may determine that it is prudent to establish an N-1-1 or an N-1-2 POC IROL for long-duration outages (such as those that are in effect for an entire season) where the TOP and the RC collaboratively determine that there is a high risk for N-1-1 or N-1-2 instability risks while the outage is in effect.

Identifying IROLs for Planned Outage Conditions

This section is intended to provide clarity on when IROLs should be established for planned outage conditions, and to provide guidance on the method that should be employed to make that determination.

When transmission or generation outages are planned, the system must be studied to determine if the planned outage creates any new instability risks that otherwise would not practically exist. When the system is operated in a “normal” mode, many types of limitations exist – thermal, voltage or stability. In “normal” mode, the system is able to support transfers throughout the various seasons that are fairly well understood. When planned outages are brought into the equation, the system may not be able to support the transfer levels that it otherwise would be able to support. TOPs routinely reduce TTCs in response to planned outage conditions as a preemptive measure to prevent commercial activity (schedules) from resulting in SOL exceedances.

Per the IRO-017 Outage Coordination process, BAs, TOPs and the RC are expected to perform studies/assessments to ensure that the BES will be in a reliable pre- and post-Contingency state while an outage is in effect. Acceptable system performance as described in the SOL Methodology is required while planned outages are implemented.

It is not the intent of the IRO-017 Outage Coordination Process or the SOL Methodology to be highly prescriptive for study requirements related to planned outages. TOPs are responsible for determining the level of study needed to achieve acceptable pre- and post-Contingency system performance while the outage is implemented. The level of complexity of TOP studies/assessments will vary depending the type and number of simultaneous outages and on the unique challenges and reliability issues posed by the outages. It is left to the judgment of the TOP to determine what level of analysis is appropriate for a given planned outage situation. TOPs are responsible for determining how far to stress their system to identify or rule out instability risks for the planned outage conditions. When determining how far to stress the system during planned outage conditions, TOPs should follow the guidance provided in the *System Stressing Methodology* section of the SOL Methodology.

While many planned outages require the development and implementation of outage specific Operating Plans to facilitate a given planned outage, some outages may also require the development of an IROL to facilitate the outage.

When planned outage studies indicate that, at reasonable and realistic maximum stressed conditions during the planned outage(s), a single P1 Contingency or a credible MC results in instability, Cascading or uncontrolled separation as described in the SOL Methodology, an IROL is warranted for that planned outage.

IROLs and Risk Management for Local, Contained Instability Impacts

When IROLs are established, the current set of NERC Reliability Standards require that System Operators take action up to and including shedding load to prevent exceeding that IROL. There may be planned or forced outage scenarios where the system is vulnerable to localized, contained instability. In prior outage scenarios where there are local, contained instability impacts, the severity and extent of the instability impact may represent an acceptable level of risk that may not warrant extreme operator action such as pre-Contingency load shedding to prevent the instability from occurring in response to a Contingency event. When such scenarios are determined to represent an acceptable level of risk, the local, contained instability risk may be managed via an Operating Plan that does not include the use of an IROL and does not include pre-Contingency load shedding.

Process for Determining Acceptable Levels of Risk for IROL Determination

When prior outage studies indicate that a localized, contained area of the power system is at risk of instability in response to the next worst single P1 Contingency or credible MC:

27. TOPs must determine the mitigations and a corresponding stability limit that would be required to prevent that Contingency from resulting in localized, contained instability. The stability limit would be expressed as a maximum flow value on a monitored interface, cutplane or import bubble for the conditions under study.

28. When studies indicate that all other mitigations have been exhausted and pre-Contingency load shedding is the only option remaining to prevent the Contingency from resulting in localized, contained instability, TOPs must determine the amount and location of load that must be shed pre-Contingency (at peak load for the period under study) to prevent the Contingency from resulting in localized, contained instability.

29. TOPs must determine the amount of load (at peak for the period under study) that is at risk of being lost due to instability in response to the Contingency. This assessment should include a determination of the physical and electrical extent of expected instability (e.g., the specific station buses that are expected to experience voltage instability, the expected voltage levels at adjacent stations that represent the boundary of impact). The assessment should also include any relay action that is expected to occur that might isolate that area of impact.

30. If the amount of pre-Contingency load shedding required to prevent the Contingency from resulting in localized, contained instability (as determined in item 28) is relatively high compared to the amount of load that is at risk due to instability (as determined in item 29), then the TOP must collaborate with the RC to determine the levels of acceptable risk and to create an Operating Plan that addresses the instability risk commensurate with those decisions. Accordingly, the Operating Plan might not include steps for pre-Contingency load shedding, depending on the risk management issues at hand. A key objective is to ensure that the mitigations prescribed in the Operating Plan are consistent with good utility practice.

31. If it is determined that the localized, contained instability represents an unacceptable level of risk, and pre-Contingency load shedding is warranted to prevent the Contingency from resulting in the local, contained instability, then an IROL should be established to prevent the Contingency from resulting in the localized, contained instability. In such scenarios, the IROL will be based on the stability limit determined in item 27, and the IROL Operating Procedure will be based on the information determined in item 28.

<u>Transient Stability IROLs</u>

A transient stability IROL is established to prevent a single P1 Contingency or a credible MC from resulting in either:

32. The loss of synchronism (from rotor angle instability or associated relay action) that results in subsequent uncontrolled tripping of BES Facilities (Cascading), or in uncontrolled separation as described in the SOL Methodology.
33. Widespread voltage collapse that occurs in the transient timeframe.

A transient stability IROL is not warranted to prevent one or more units from losing synchronism and tripping offline, provided that studies demonstrate that the transmission system remains stable after the units are lost.

Voltage Stability IROLs

A voltage stability IROL is established to prevent a single P1 Contingency or a credible MC from resulting in:

34. An undeterminable area or a wide area of the BES experiencing voltage instability
35. Voltage instability that consequently leads to Cascading or uncontrolled separation

Voltage stability IROLs are determined from transient and post-transient analysis methods, techniques and assumptions as described in the SOL Methodology.

Facility Rating-Based IROLs

Facility Rating-based IROLs are established when studies show that a Contingency results in excessive loading on a Facility, which triggers a chain reaction of Facility disconnections by relay action, equipment failure or forced immediate manual disconnection of the Facility (for example, due to line sag or public safety concerns), consistent with the NERC definition of Cascading. The Cascading test is used to determine Cascading based on available Facility Ratings. Facility Rating-based IROLs prevent non-stability related Cascading due to excessive post-Contingency loading of Facilities [NERC Standard FAC-011-3 R3.7]. While such IROLs may be established as long-term IROLs for N-1-1 or N-1-2 operations, they may also be established for credible MCs, or planned outage conditions to address the next worst single P1 Contingency or the next worst credible MC.

For Facility Rating-based IROLs, the IROL will exist on the initial excessively loaded Facility that is expected to be disconnected by automatic or manual action, leading to Cascading. The IROL value will be the lesser of the relay trip setting or 125 percent of the Emergency Rating. These IROLs will be monitored for their performance in the post-Contingency state through RTAs.

Credible MC (Example 1):

Studies show that credible MC X results in Facility Z loading up to or beyond the lower of the relay trip setting or 125 percent of its Emergency Rating. Cascading tests indicate that the MC X would result in Cascading. An IROL is established to prevent MC X from resulting in Cascading.

36. The IROL is in effect when it becomes a risk to reliability. For planned outage conditions, the IROL may be in effect during the planned outage. Otherwise, the IROL may need to be in effect at all times.

37. The IROL exists on the initial excessively loaded Facility that is expected to be disconnected by automatic or manual action, leading to Cascading. Accordingly, the IROL is the MVA value on Facility Z that results exceeding the lower of the relay trip setting or 125 percent of its Emergency Rating.

38. The IROL is monitored as the calculated post-Contingency flow on Facility Z in response to MC X.

39. The IROL is exceeded when Real-time Assessments indicate that MC X results in flow on Facility Z exceeding the lower of its trip setting or 125 percent of its Emergency Rating.

<u>Long-term N-1-1 Facility Rating Based IROL (Example 2):</u>

"All transmission Facilities in service" studies show that the loss of Facility X is expected to render the system in a position where a subsequent Contingency on Facility Y would result in Facility Z loading up to or beyond the lower of the relay setting or 125 percent of its Emergency Rating. Cascading tests indicate that the loss of Facility X followed by a subsequent Contingency on Facility Y (with no system adjustments between Contingencies) would result in Cascading, i.e. that the loss of line X would render the system in an N-1 insecure state for Contingency Y. An IROL is established to prevent the loss of Facility X, followed by a Contingency of Facility Y, from resulting in Cascading.

40. The IROL exists on the initial excessively loaded Facility that is expected to be disconnected by automatic or manual action, leading to Cascading. Accordingly, the IROL is the MVA value on Facility Z that results in its tripping, in this case it is 125 percent of its Emergency Rating.

41. The IROL is monitored as the calculated post-Contingency flow on Facility Z for the loss of Facility Y.

42. The IROL is not in effect unless there is a forced/urgent outage or Contingency of Facility X. The IROL becomes effective when Facility X experiences a forced/urgent outage.

43. The IROL is exceeded when there is a forced/urgent outage on Facility X, and subsequent Real-time Assessments indicate that a Contingency of Facility Y results in flow on Facility Z exceeding the lower of its relay trip setting or 125 percent of its Emergency Rating.

U. IROL T_V in the Peak RC Area

The IROL T_V in the Peak RC Area shall be less than or equal to 30 minutes [FAC-011-3 R3.7]. The default IROL T_V value is 30 minutes. However, shorter duration IROL T_V values may be established in coordination with the impacted TOPs based on relay/protection settings and other considerations.

V. Peak's Process for Addressing IROLs Established by Planning Coordinators (PC) and Transmission Planners (TP)

FAC-014-2 Requirements R3 and R4 require PCs and TPs to establish SOLs and IROLs for its PC or TP area consistent with its PC's SOL Methodology for the planning horizon. Requirements R5.3 and R5.4 require PCs and TPs to communicate those SOLs and IROLs to its RC.

Peak implements the following process for each IROL identified by the PC or TP pursuant to the requirements in FAC-014-2:

1. Peak communicates with the PC/TP to understand the nature of the IROL, the assessments performed, the Contingencies that are associated with the IROL and the criteria used in the analysis.
2. Peak applies the methodology and criteria in Peak's SOL Methodology for potential IROL establishment for use in the Operations Horizon. This may require Peak to perform additional studies in collaboration with the associated TOPs, taking into consideration input from the PC/TP.
3. Peak establishes IROLs based on the results of this collaboration.

W. Peak's Role In Ensuring SOLs are Established Consistent with the SOL Methodology

FAC-014-2 Requirement R1 requires the RC to ensure that SOLs and IROLs for its RC Area are established and that the SOLs and IROLs are consistent with its SOL Methodology. Peak performs the following functions to meet this requirement [NERC Standard FAC-014-2 R1]:

1. Peak ensures that Facilities in the West-wide System Model (WSM), which is Peak's Energy Management System (EMS) model, are associated with the Facility Ratings as provided by TOPs, consistent with this SOL Methodology.

2. Peak performs a coordination and facilitation role in the seasonal planning process, and has a predominant role in the IRO-017 Outage Coordination Process for the RC Area.

3. Peak ensures that buses in the WSM are associated with the System Voltage Limits as provided by TOPs, consistent with this SOL Methodology.

4. Peak reviews the stability limitations provided by TOPs to ensure they are established consistent with the SOL Methodology. Peak makes a final determination whether the stability limitations are declared an actual IROL.

5. Peak ensures RC System Operators and engineers have awareness of identified stability limitations and IROLs.

6. Peak performs Real-time monitoring and RTAs to determine SOL exceedances and to determine if the system has unexpectedly entered into an N-1 or credible N-2 insecure state. If the system has unexpectedly entered into an N-1 or credible N-2 insecure state, Peak mitigates this condition within 30 minutes per internal Operating Plans.

7. Peak's Real-time Contingency Analysis (RTCA) application provides indication of whether acceptable thermal and voltage system performance is being achieved for the post-Contingency state given actual system conditions. Peak posts its RTCA results in the secure area of the PeakRC.org website for review by TOPs. If a TOP notices any issues with the posted results, the TOP should coordinate with the RC to have those issues addressed.

8. Peak utilizes a Real-time Voltage Stability Analysis (VSA) tool and communicates the results of this tool to impacted TOPs.

X. System Study Models [NERC Standard FAC-011-3 R3.4]

The Peak RC Area covers the entire Western Interconnection, less Alberta, and contains several intra-regional DC transmission lines. However, except with Alberta, the Peak RC Area is not connected synchronously with other RC Areas. Interregional DC lines tie Peak RC to its RC neighbors.

While Facility Ratings and System Voltage Limits may not require a TOP study for their establishment, stability limitations are identified as a direct result of system studies. TOPs within the Peak RC Area generally use any of three study models for identifying instability risks and establishing stability limitations: their respective EMS models, Peak's WSM, and off-line models based on approved WECC operating base cases. Development of the WECC operating base cases is coordinated by the WECC Regional Entity. The cases for each season are approved by the WECC Regional Entity.

Peak uses both the WSM and the WECC operating base cases when performing system studies. The WSM uses a network model of the entire Western Interconnection BES. While the model contains some detail for non-BES Facilities, such as lower voltage generation models and the sub-100 kV elements identified by the TOPs to impact the BES, much of the system at these lower transmission voltages is reduced to a mathematical equivalent. Loads served over radial lines are typically lumped at the delivery bus. The WSM consists of transmission lines, transformers, circuit breakers and switches, reactive devices, generation units, step-up transformers, loads and other relevant electrical components.

Though the WECC operating base case is not a breaker-to-breaker model, it consists of similar information as mentioned above as well as additional details and modeling information necessary to perform dynamic and transient stability studies.

1. TOPs and the RC shall use study models that include the entire Peak RC Area for establishing stability limitations [NERC Standard FAC-011-3 R3.1]. The study model must include any critical modeling details from other RC Areas that would impact the Facility(ies) under study. That said, it is acceptable to use models that equivalence portions of the Peak RC Area's full loop model, provided that doing so does not impede capturing interactions between the TOP Area and the external systems or vice versa.

Y. TOP Communication of SOLs to Peak

This SOL Methodology contains several requirements for TOPs to communicate SOL information to Peak "per the RC Instructions." These RC instructions are maintained outside of the SOL Methodology to provide the flexibility needed for modification without having to revise the SOL Methodology.

The RC instructions referenced in the SOL Methodology are posted in the secured area of PeakRC.org website.

Z. RC Communication of SOL and IROL Information to Other Functional Entities

Peak provides SOLs and IROLs to those entities listed below that have provided a written request that includes a schedule for delivery of those limits [NERC Standard FAC-014-2 R5]. These entities include [NERC Standard FAC-014-2 R.5.1]:

1. Adjacent Reliability Coordinators and Reliability Coordinators with a reliability-related need for those limits
2. Transmission Operators within the Peak RC Area
3. Transmission Planners within the Peak RC Area
4. Transmission Service Providers within the Peak RC Area
5. Planning Authorities/Planning Coordinators within the Peak RC Area

Peak provides the following supporting information for each IROL as part of the corresponding IROL Operating Procedure:

6. Identification and status information of the associated Facility (or group of Facilities) that is critical to the derivation of the IROL [NERC Standard FAC-014-2 R5.1.1]
7. The value of the IROL and its associated T_V [NERC Standard FAC-014-2 R5.1.2]
8. The associated Contingency(ies) [NERC Standard FAC-014-2 R5.1.3]
9. The type of limitation represented by the IROL (e.g., voltage collapse, transient stability) [NERC Standard FAC-014-2 R5.1.4]

Contact Information

For information about the Peak RC SOL Methodology for the Operations Horizon, or if you have any questions, please contact rc.sol.help@peakrc.com.

Version History

Version	Date	Action	By	Change Tracking
1.0	01/01/2009	Issued for implementation		**Original procedure**
2.0	07/08/2009	Revised		Reformatting
3.0	10/30/2009	Revised		Multiple Contingency Criteria changes
4.0	02/04/2010	Revised		WECC RC format. Classification changed to external
5.0	10/27/2011	Revised		Changed classification to "Public"
6.0	01/23/2012	Revised	Vic Howell	**Major Revision** • WECC RC SOL Methodology Phase I project
6.1.	04/02/2012	Revised	Vic Howell	• Changed effective date to 6/4/2012 • Corrected typo in BES Performance Requirements section • Minor change in WECC RC System and System Models section
7.0	08/30/2013	Revised	Jaison Tsikirai	**Major Revision** • Peak RC SOL Methodology Phase II project • Merged the SOL Methodology with the "Establish and Communicate SOLs" Version 3.1 procedure • Document 'Peaked' following the 2/12/14 FERC approval of bifurcation. No version change. No issue date change. Effective date remains the same.
7.1	5/4/2016	Revised	Vic Howell	Address FERC Settlement issues and minor corrections. Effective immediately upon release.
8.0	1/13/2017	Revised	Vic Howell	**Major Revision**

				• Better aligns with new TOP and IRO standards • Implements concepts in the NERC SOL White Paper • Implements Path Operator Task Force (POTF) Recommendation
8.1	2/24/2017	Revised	Vic Howell	**Minor Revision** • Addressed retirement of TOP-007-WECC-1a Reliability Standard in Section K • Corrected minor typos

Appendix A

Terms Used in the SOL Methodology for the Operations Horizon

Terms used as defined/described in the SOL Methodology for the Operations Horizon:

Always Credible Multiple Contingency – A multiple Contingency (MC) that, based on historical performance and TOP risk assessments, have a sufficiently high degree of likelihood of occurrence such that the TOP determines that the MC should be protected against in all phases of the operations planning process and in Real-time operations.

Conditionally Credible Multiple Contingency – A multiple Contingency (MC) whose credibility is a function of observable system conditions.

Operations Horizon – A rolling 12-month period starting at Real-time (now) through the last hour of the twelfth month into the future.

Operational Transfer Capability (OTC) – (from the retired WECC standard TOP-STD-007-0): The OTC is the maximum amount of actual power that can be transferred over direct or parallel transmission elements comprising:

- An interconnection from one Transmission Operator area to another Transmission Operator area; or
- A transfer Path within a Transmission Operator area.

System Voltage Limit – The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

Terms used as defined in the NERC Glossary of Terms:

The following list of terms from the NERC Glossary of Terms are used in the SOL Methodology. The definitions from the NERC Glossary of Terms are not included here. Please reference the NERC Glossary for the definitions.

Bulk Electric System (BES)

Cascading

Contingency

Corrective Action Plan

Element

Emergency Rating

Facility

Facility Rating

Fault

Interconnection Reliability Operating Limit (IROL)

Near-Term Transmission Planning Horizon

Normal Clearing

Normal Rating

Operating Plans

Operational Planning Analysis (OPA)

Operating Procedure

Operating Process

Planning Assessment

Real-time

Real-time Assessments (RTA)

Reliability Coordinator (RC) Area

Remedial Action Scheme (RAS)

System

System Operating Limit (SOL)

System Operator

Total Transfer Capability

Transfer Capability

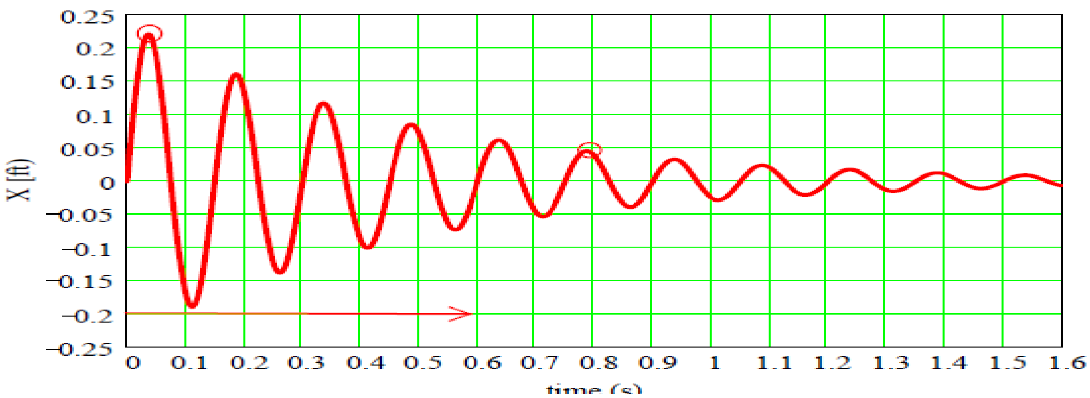
Transmission Operator (TOP) Area

Undervoltage Load Shedding (UVLS) Program

Appendix B

Damping Ratio Calculation Example

Measuring damping is best performed a) after all significant automatic schemes have operated; and b) should measure damping over oscillations toward the end of the simulation rather than at the beginning of the simulation. As an example, a good trigger for measuring signal damping during a ten-second run is about two seconds after the fault clears as most automatic schemes have switched and the fault should be fully cleared.



Log-dec is derived from ratio: $\delta := \frac{1}{n} \cdot \ln\left(\frac{X_o}{X_n}\right)$ $\delta = 0.305$

Note that the approximate formula = $\delta / (2 \cdot \pi)$ = 0.049 × 100 =4.9% damping ratio

Where n = Number of periods between measurement X_o and measurement X_n

Periods = 5 in example

X_o is magnitude of oscillation at first measurement

X_n is magnitude of oscillation at second measurement

Ln = log in base e

Appendix C

Use of Automatic Schemes

NOTE: This table is intended to summarize and reflect the language in the *Allowed Uses of Automatic Mitigation Schemes* in the Operations Horizon section of the SOL Methodology. If discrepancies are perceived to exist between the table and the language in the SOL Methodology, the language in the SOL Methodology shall prevail.

NOTE: For every YES: Studies must show reliability issues are resolved. If any automatic scheme *does not perform as designed, causes reliability issues or is expected to be unavailable*, an Operating Plan with pre-Contingency mitigation actions must address reliability issues.

	Contingency results indicate system stability, no Cascading, and no un-controlled separation	
	Non-outage Conditions	Outage Conditions
	Single Contingency	Single Contingency
Use of non-load-shed automatic schemes allowed?	YES	YES
Use of load-shed automatic schemes designed for specific Contingencies allowed?	YES[2,3]	YES[2,3,4]

	Contingency results indicate system instability, Cascading, or uncontrolled separation			
	Non-outage Conditions		Outage Conditions	
	Single Contingency	Always Credible and Conditionally Credible MC[1]	Single Contingency	Always Credible and Conditionally Credible MC[1]
Use of non-load-shed automatic schemes allowed? (no single point of failure allowed)	YES	YES	YES	YES
Use of load-shed automatic schemes designed for specific Contingencies allowed? (no single point of failure allowed)	YES[2,3]	YES	YES[2,3,4]	YES

[1] Note that automatic schemes that are intended and designed to address certain non-credible MCs (including extreme event Contingencies) are allowed to be relied upon to meet their intended design objectives for those non-credible and extreme event Contingencies; however, the SOL Methodology does not require assessment of – and therefore, determination of acceptable performance for – non-credible and extreme event Contingencies in the Operations Horizon.
[2] Load-shed schemes may be relied upon and utilized in operations for single P1 Contingencies if the scheme's impact is limited to a small amount of load in the local network area per their design according to the allowances in Table 1 of TPL-001-4 for single P1 Contingencies.
[3] TOPs are expected to take action up to, but not necessarily including pre-Contingency load shedding to, if at all possible, pre-position (or re-position) the system to avoid reliance on the load shed scheme.
[4] Applies when the planned or forced outage makes the specific credible MC in the planning horizon, for which the load-shed automatic scheme was designed, become a single Contingency in the operations horizon.

Attachment P

IID Energy Consumers Advisory Committee Meeting Minutes

Attachment P-1

IID Energy Consumers Advisory Committee Meeting Minutes
from February 1, 2016

IMPERIAL IRRIGATION DISTRICT

Energy Consumers Advisory Committee

Meeting Minutes of Feb. 1, 2016

IID Boardrooms - 1285 Broadway, El Centro / 81-600 Avenue 58, La Quinta

1. CALL TO ORDER / PLEDGE OF ALLEGIANCE / ROLL CALL

Chairwoman Esther Gomez called the meeting to order at 6:02 p.m. and Michael Anderson led the Pledge of Allegiance. With 17 members present, a quorum was achieved.

Members present (El Centro): Michael Anderson, Thomas Brinkerhoff, Eugene Bumbera, Esther Gomez, John Hernandez, Shorty Hickingbottom, Gil Perez, Jeffrey Plourd and Eric Reyes

Members present (La Quinta): Steven Bayard, Becky Broughton, Richard Macknicki, Brian Macy, Lee Osborne, Patricia Saleh, Betty Sanchez and Lupe Ramos Watson

Members absent: Gerald Gauna, Paul Gibson and Mark Weber

2. PUBLIC COMMENT

Ms. Aurelia Perez expressed her views about the comportment of various ECAC members.

3-4. CONSENT CALENDAR

The following items were included in the Consent Calendar.

3. Meeting Minutes of Jan. 4, 2016
4. January 2016 Attendance Report

Mr. Macy questioned the accuracy of the minutes on Page 3, which reported the motion passed 13-1, but two people were listed as opposing. Ms. Gonzales informed a document is kept with all the motions and the votes, which aligns with the minutes. Staff will check the video to see if there is a mistake and make a correction, if necessary.

A motion was made by Mr. Hernandez and seconded by Mr. Plourd to approve the ECAC Meeting Minutes of Jan. 4, 2016. Motion passed 10-0-4, with Ms. Broughton, Mr. Bayard, Mr. Perez and Mr. Brinkerhoff abstaining.

5. COLGREEN NORTH SHORE, LLC 75-MEGAWATT TRANSMISSION SERVICE AGREEMENT

Ms. Kelli Fitzgerald, contract specialist, senior, presented the ColGreen North Shore, LLC Long-Term, Firm Point-to-Point Transmission Service Agreement. Commencing Jan. 1, 2017, the 10-year agreement will serve the proposed 75-MW ColGreen North Shore generating facility in Riverside County.

Mr. Perez inquired about the cost of installation. Ms. Fitzgerald recounted there is a generator interconnection agreement associated with the project; the customer will construct the network upgrades required to accept the interconnection and the injection of power. The network upgrades under the contract are approximately $4.3 million, which means Colgreen will get transmission rate credits; once [exhausted], they will be billed and IID will begin collecting revenues under this contract.

Mr. Perez asked if the initial expense will be paid by the customer and whether the project will be done in accord with IID standards. Ms. Fitzgerald affirmed both and added [the cost] will be paid upfront by the customer, who will be reimbursed by IID as service is taken on the transmission system.

A motion was made by Mr. Perez, seconded by Mr. Bayard and unanimously passed to recommend approval of the ColGreen North Shore LLC Long-Term, Firm Point-to-Point Transmission Service Agreement.

6. OCOTILLO SOLAR, LLC GENERATOR INTERCONNECTION AGREEMENT 1215-42

Ms. Fitzgerald also proposed the Ocotillo Solar LLC Generator Interconnection Agreement 1215-42. The 50-MW Ocotillo Solar photovoltaic project seeks interconnection to IID's 92-kV "R" Line via an in-and-out configuration with a planned in-service date of October 2016.

Noting the project would be sited in San Diego County, Mr. Bayard asked why the power is being [transmitted] through IID's transmission lines and where it is going. Ms. Fitzgerald explained the site is in San Diego County, but is connecting to an IID facility. She did not believe the project has a power purchase agreement at this time, so it is not yet clear where the generator will export.

Mr. Perez sought [which party] would offset the $1.6 million differential from the total estimated cost and funding provided. Ms. Fitzgerald advised the developer would assume the cost, including common network upgrades and any other work IID will be performing. The district will remain revenue neutral throughout the construction process.

Assuming the developer would pay 100 percent of the $25 million system upgrade cost estimate identified on pages 110 and 111, Mr. Plourd asked the amount the district would collect annually for the use of the transmission line. Ms. Fitzgerald disclosed the $25 million cost is the total for Cluster 1, which comprises five or six participants. This particular proportional share is $2.8 million. The other customers, including ColGreen, will be making up the remaining overall cost. IID's revenue would be detailed under a transmission service agreement, which has not yet been executed, but would apply IID's economic development rate. Calculating $3.38 per megawatt-hour times the total 50-megawatt output, the cost would be less than the $663,000 estimated for ColGreen.

A motion was made by both Mr. Brinkerhoff and Mr. Bayard and seconded by Mr. Perez. The motion passed unanimously to recommend approval of the Ocotillo Solar, LLC Generator Interconnection Agreement 1215-42.

7. IV SUBSTATION TO DIXIELAND 230-KILOVOLT INTERCONNECTION PROJECT CANCELLATION

Mr. Jesse Montaño, consultant, Planning & Engineering, proposed the cancellation of the Imperial Valley to Dixieland 230-kV Interconnection Project. The project consists of the construction of a new 230-kV transmission line between the two substations, as well as the associated terminal equipment. A transmission capital project assessment determined the project installation minimizes the maximum import capability by 200 MW with the California Independent System Operator Balancing Authority; therefore, staff recommends the cancellation of the project and settlement of equipment procurement and any other project costs.

Ms. Saleh questioned what led to the miscalculation of energy which would be allowed through [the CAISO] when the project was originally conceived. Mr. Montaño believed the focus was on what was necessary to upgrade the IID system, excluding the regional impact. As IID is situated between two major CAISO 500kV lines, certain upgrades on the IID system will decrease the amount of energy that can be exported, which was not taken into consideration when this project was originally proposed.

Ms. Saleh inquired if determining regional impacts is customary as the costs are considerable. Mr. Montaño affirmed and added that a regional assessment will be conducted for every project proposed. Internal and external impacts will be brought to the ECAC and the board. He confirmed the regional assessment was not done prior to his involvement.

Mr. Osborne asked whether the $3.8 million spent helped the system. Mr. Montaño revealed about 75 percent of the $3.8 million was for equipment, which is in storage; other costs included engineering and transportation. Staff is exploring where the transformer can be sited. If negotiations go nowhere with the manufacturer, it will be situated and dressed at one of the substations; however, they are looking at projects that can utilize this specific transformer.

Mr. Osborne inquired whether the $3.8 million included the transformer and Mr. Montaño affirmed.

Ms. Saleh questioned how the redundancy and system strengthening issues are being addressed. Mr. Montaño disclosed assessments are being conducted on every pole of the "S" Line, which is one of IID's ties with San Diego Gas & Electric and the CAISO. Increasing the circuit's capacity is being avoided as that allows more energy to be imported into California from other areas aside from the IID. [Staff] is working on a project to take the circuit out of service during winter months to enable tower replacement and maintain system reliability. This project is anticipated to occur mid- to late-2017.

Mr. Perez requested the cost of the transformer and whether it is included in the amount not utilized. Mr. Montaño specified the amount is $2.9 million, but to move and dress the transformer is about $500,000, which is needed to finalize the project.

Mr. Perez inquired about canceling and simply paying the building cost incurred. Mr. Montaño expounded that negotiations are in process [with the manufacturer]. [The project] was stopped before construction began on the transformer, but equipment had been procured. If IID is allowed to cancel for a fee, which could be more than $100,000, it will be brought to the ECAC and the board.

Mr. Montaño affirmed Mr. Anderson's understanding of the transformer expenditure was in the amount spent to date, which will be diverted to a different project elsewhere, if used.

Mr. Brinkerhoff asked when the project was first awarded. Mr. Montaño believed the project began in 2011, but would respond after checking. Mr. Brinkerhoff requested the timeline as he hoped the district would not run into this problem again in the future. Mr. Montaño agreed.

Mr. Hernandez was curious as to Mr. Vicken Kasarjian's whereabouts, to which Chairwoman Gomez informed he indicated he would be out of town.

It was Mr. Hernandez' understanding this was a multiyear project, as well as others, comprising millions of dollars. At some point, the projects came to the committee because staff indicated they were needed for reliability of the system and now saying they are not [needed]. Mr. Hernandez inquired what changed other than internal management and another set of eyes or if there was an external set of eyes that said to change this. He then asked Ms. Belen Valenzuela, chief financial officer, to shed light on the multiyear facet: If there are funds budgeted in prior years that are now having to be redirected, what impact will that have on the budget and/or what factors will be taken in terms of the energy cost adjustment or rates?

Addressing Mr. Hernandez' first question, Mr. Montaño reported, in regards to this specific project, it is the regional view and the impacts this project had on the IID system. When looking at this project regionally, it was identified that this project decreases the amount IID can export into California.

Mr. Hernandez questioned who looked at the project regionally from outside, listing the Federal Energy Regulatory Commission, North American Electric Reliability Corporation or consultants as examples. Mr. Montaño stated it was the responsibility of IID's Planning & Engineering [Section]. Mr. Hernandez pressed further as Mr. Montaño mentioned it was external. Mr. Montaño explained the grid is integrated so assessments require not only looking at IID's system, but looking at how generation impacts IID and the neighboring systems. Prior to 2013, IID did not have a lot of view into the external systems--the CAISO, Arizona Public Service and Western Area Power Administration. [IID] began a program to allow a look into multiple substations in the CAISO. CAISO began sharing information and IID began sharing data with the CAISO; APS and Western Area Power Administration also started sharing data. Focus on regional planning and assessment evolved from the 2011 outage. System Operations has done a fantastic job monitoring neighboring systems on a real-time basis. Staff is now doing long-term planning studies in the same manner and reviewing individual upgrades on the IID system in terms of their internal and external impacts. Putting this project into service degraded the MIC by 200 megawatts, which was identified previously with another project which was built, and suddenly the MIC into California dropped to zero from the IID system. That is when the focus was placed on the internal and regional impacts of projects.

Regarding the second part of Mr. Hernandez' question, Ms. Valenzuela revealed the budgeting for the unspent amount matters if it was customer funded by the developer; if not, the district would borrow for it. The unspent money would lower IID's debt service, unless projects are reprioritized and the money is used for projects not identified in the capital plan. At that point, it would just be reallocated to another priority project.

Mr. Hernandez probed further into the amount of the debt service that goes into the base rate for this project. Ms. Valenzuela revealed the annual debt service goes into the base rate, but she did not know what percentage of the base rate pays for debt service, but would look into it. Much of the Energy Department's base rate is operations and maintenance expense.

Mr. Hernandez inquired if staff can do whatever they wish with a portion of those funds and if the portion from debt is placed into the following year's budget. Ms. Valenzuela answered in the affirmative and added if the capital money is not spent that year, the staff must come back with a new capital plan for the new year. Based on that capital plan, the debt service is [calculated].

Mr. Hernandez wondered if [staff] can do as they wish with money left over and Ms. Valenzuela explained that major work authorizations must be done for projects of this size; the MWA must go to the ECAC and the board and identify [the source] of those funds.

Mr. Perez further questioned whether the amount would go into the surplus. Ms. Valenzuela advised it would not go into the total surplus. When the budget is done, staff calculates revenue which is matched to expenses so it would be that portion of the capital project which would be paid through debt service. If it totaled $8.3 million, for example, staff would figure how much of that would be borrowed and the debt service portion of the borrowing goes against the revenues.

Mr. Perez asked if IID would be borrowing money to cover that expense. Ms. Valenzuela informed she would have to determine if the project was customer funded. Mr. Montaño interposed the project was not customer funded.

Mr. Plourd inquired how many such projects the ECAC may be looking at in the future. He thought it was a great thing these four projects will be $20 million worth of unspent money that was unnecessary. Mr. Montaño briefed that this is the fifth project being canceled, including the next agenda item. Of the five projects, the total estimated project cost is $53 million, the amount spent is $18 million, the amount not utilized is $35 million and staff is bringing approximately eight more projects to the ECAC. Mr. Montaño stressed they are not just looking at canceling projects, but relocating some of the funds to projects that were identified in the one, five and 10-year transmission study plans. [Staff] identified circuits in the northern system requiring upgrades and the worst performing distribution circuits on the system. They will focus on those circuits and allocate funds to repair or replace the deterioration of circuits. Those costs are not as substantial as the projects being canceled.

Ms. Valenzuela advised [the cancellations] will allow the Energy Department to look at the 10-year capital plan, bring some projects forward and reprioritize. This will also defer future planned rate increases; the past capital plan showed another rate increase would be needed in three years.

Mr. Plourd thought canceling unnecessary projects was good. As learned previously, there are a few places in La Quinta and Coachella with more than normal outages that can use some of those dollars to fix those situations.

Mr. Anderson asserted the budget numbers do not add up. Mr. Montaño informed they are approximate amounts and he anticipates spending additional moneys unloading and building a berm for the transformers. [Staff] is setting aside some moneys to completely close the project.

Mr. Anderson said he understood and stated that $35 million will not be utilized, but the ECAC is only seeing a piecemeal of $7 million. He asked if it was possible to provide a big picture of current and future projects so those projects that need to be “ditched” can be gathered and bring forth those projects so the Coachella outages can be fixed. Mr. Montaño assured he would give the committee the running total and an estimate looking forward to give the committee the entire picture at the next meeting.

Mr. Brinkerhoff questioned if future projects that will be brought to the ECAC for cancellation are due to the [MIC] reduction into the CAISO. Mr. Montaño responded in the negative--not all are due to the decrease in the MIC. [Staff] ran one, five and 10-year studies and could not find the justification--either reliability, overload or the need for project interconnection.

Ms. Saleh concluded that [staff] was originally looking at this because of the power outage and it appeared to her this is a sort of hit-and-miss method, which people are not trying to do. She recounted that Mr. Montaño said it was not allowing the electricity through [to the CAISO], but is it possible this was part of what created the power outage? She related that he further said it minimizes the MIC and IID was trying to shore it up so it was stronger, but in reality it was weakened. She questioned if it is possible part of why IID did not have the electricity it needed was through this engineering feat. Mr. Montaño stated the studies are physics, so it is very precise. To ensure the quality of the study base case, which is essential to the output of any report or study conducted, [staff] tore apart the base case and rebuilt it piece by piece to validate that it was completely accurate before running any assessment on the IID system for cluster studies, one-year planning studies, etc. The condition of the system and the data available today compared to that in 2011 is night and day. [Staff] has phase angle and real-time data from the CAISO and all the neighboring utilities and the benefit of additional accurate data, which is being utilized to run assessments today.

Ms. Saleh recognized the ECAC can assume it is the best engineering know-how until staff gets more data. Mr. Montaño assured [staff] will never bring a project to the ECAC unless a study shows it is necessary and all the required assessments on the system have been conducted to ensure it will not negatively impact the IID in the next 10 years.

Ms. Saleh commented there are $35 million worth of [projects] that might be canceled now because they were not really necessary. She knows studies were done at that time and having additional facts adds to the accuracy, but that is a lot of money. The ECAC voted and accepted the figures and calculations of those who did this in the past. She wondered how the ECAC can know the field was covered in the future. Mr. Montaño reiterated that the amount of data that [staff] is able to acquire and its accuracy are night and day. Ms. Saleh acknowledged that is helpful; nobody is superhuman.

A motion was made by Mr. Perez, seconded by Mr. Bayard and unanimously passed to recommend cancellation of the IV Substation to Dixieland 230-KV Interconnection Project.

8. “S” LINE 230-KILOVOLT TRANSMISSION LINE PROJECT CANCELLATION

Similar to the IV-Dixieland Project, Mr. Montaño also recommended the cancellation of the “S” Line 230-KV Transmission Line Project, which consists of rebuilding the existing circuit from El Centro to Imperial Valley substations. Staff also conducted a transmission capital assessment on this project to determine the effect to the MIC at each inter-tie with the CAISO BA and found the installation of a new “S” Line circuit interconnecting to the Imperial Valley Substation minimizes the MIC by approximately 200 MW; therefore, he recommends canceling the project and settling the equipment procurement and other project costs.

A motion was made by Mr. Hernandez, seconded by Mr. Perez and unanimously passed to recommend cancellation of the “S” Line 230-KV Transmission Line Project Cancellation.

9. PILOT KNOB “D” LINE RELAY REPLACEMENT MAJOR WORK AUTHORIZATION PROJECTS 100643

Ms. Lucy Arias, project coordinator, presented the MWA for Projects 100643, the Relay Protection Replacement, which involves replacing the existing electromechanical and differential relay protection with new Schweitzer Engineering Laboratories protection relays for the “D” Line from Pilot Knob to Knob substations.

A motion was made by Mr. Hernandez, seconded by Ms. Saleh and unanimously passed to recommend approval of the “D” Line Relay Protection Replacement Major Work Authorization Projects 100643.

10. DEPARTMENT UPDATE

Mr. Pete Garris, deputy energy manager, introduced himself as the newest member of the IID Energy team, was excited to be present and was looking forward to the next three years or so. Ms. Jamie Asbury, deputy energy manager, and Ms. Angela Evans, manager, Distribution Services & Maintenance Operations, would be presenting, but the ECAC would be hearing more from him in the next go-round.

Ms. Asbury reviewed that which would be addressed at the board meeting the following day on behalf of Mr. Vicken Kasarjian, energy manager. The staff wants to make certain the committee and the board are updated on a number of ongoing initiatives in California and regionally.

Ms. Asbury reported Senate Bill 350 was recently enacted, which takes the California Renewables Portfolio Standard from 33 to 50 percent by 2030. IID must meet the 50 percent by a combination of additional renewable procurement and energy efficiency measures. A legislative mandate from SB 350 forms a governance structure for the CAISO that extends beyond California. CAISO is morphing into a more regional organization so staff has been participating and monitoring that on a number of fronts.

Ms. Asbury further informed that staff is also working on the Renewable Energy Transmission Initiative that was promulgated by the California Energy Commission. The RETI 2.0 process identifies transmission projects that will be needed to help meet the 50 percent requirement. Staff has been vigorously saying IID has capacity over Path 42, shovel ready projects in Imperial County and secondary benefits by siting projects close to the Salton Sea. Staff is bringing together all of the tools IID has to push the agenda that projects sited in Imperial County and interconnected to the IID system are a good thing. Staff will continue to keep the committee updated, and vigorously advocate for that. Whatever the ultimate decision is that [emerges from] the RETI 2.0 process, which is very aggressive, they look to have those transmission elements identified by the end of 2016.

There is a regional look at the CAISO's transmission access charge and its resource adequacy requirements. CAISO is expanding beyond its California footprint and staff will make certain they are vigorously involved in that, as well, to see how that impacts IID.

Additionally, the commercial operation on a 20-MW photovoltaic project in Imperial County was proudly and happily achieved in the past week and staff attended its ribbon cutting. The ECAC approved the generator interconnection [agreement]; that project went from paper to generating and sending power to SDG&E to serve its coastal customers. Staff was very pleased.

Site work has commenced on the Battery Energy Storage System project, including grading preparation where steel buildings are anticipated to be delivered Feb. 14. There are weekly construction meetings on site so there is much activity close to the El Centro Switching Station.

Ms. Asbury also imparted that Mr. Kasarjian had a very positive and productive meeting with the Torres-Martinez Indian Tribe. He is taking the time to meet with major customers, entities, businesses and community organizations that are located within the IID service territory. The energy manager looks at IID as a business partner to further better business relationships. He is very proactive in looking for opportunities where they may exist. Staff will be following up and reporting.

A backlog of rooftop solar applications in excess of 1,195 was discovered. Staff immediately launched and streamlined the process significantly and the applications are now moving forward quicker. It is staff's goal to clear the backlog by the end of the first quarter of 2016 and report the progress monthly to the ECAC and the board. Like the interconnection process, the goal is to get the customer interconnected so staff is looking to unburden and streamline those processes to make them more efficient.

Ms. Sanchez recalled one of the first meetings she attended in which the audience was talking about the backlog and asked for an elaboration on why there is a backlog. Ms. Asbury explained there are a number of factors as projects are not all similarly situated. Staff is moving quickly on those that are easily processed; however, some projects require panel upgrades or additional engineering work and some are larger than others. Also, there were a number of departments that were touching the process so those touchpoints were removed and were centralized into the Energy Management & Strategic Marketing group. There are also a number of issues with the backlogs, the jurisdictional authorities and some projects got caught in limbo. So, staff has taken a very proactive and aggressive approach as they do not want additional complaints. Once the backlog is cleared, it will be a much more streamlined process going forward.

Ms. Sanchez asked if the solar companies were informed that this process has been cleaned up. Ms. Asbury advised that since staff is moving quicker on them and additional staff was trained to set bidirectional meters, they are going the extra mile to sort of do that. Some solar companies have asked more questions about the process, but staff will absolutely have a stakeholder meeting, which is being scheduled with the jurisdictional authorities. Staff wants to ensure [the jurisdictions] understand IID's requirements and make clear IID understands theirs.

Ms. Saleh reported she has been reading about the fines that other investor-owned utilities want to place on people who get renewable energy sources, like solar, because they are not using enough electricity from the investor-owned utility. Yet the IOU has to [maintain] the service in order to serve the customer. Ms. Saleh asked if that was likely to happen here. Ms. Asbury informed it is an interesting challenge all utilities are now confronting and there are ways to mitigate it. With net energy metering customers, the law says there are only so many things [a utility] can do. IID still must have generation available and serve [those customers] when they cannot serve themselves. Those customers do not pay a demand charge. Once the NEM cap is satisfied, there are other ways to mitigate those issues. In other states, it is clear how it should not be done because the solar developers have a very strong lobby and have certainly been aggressive in their complaints against it. IID wants to ensure it is done right and through proper ratemaking authority. All customers must bear the expense to serve them and we want to ensure those costs are not socialized across other rate classes.

Ms. Saleh inquired if people will be charged a fine if they spend the extra money for backup storage for their solar systems as they are theoretically off the grid. Ms. Asbury was uncertain if they are couched as fines, but are referred to as a demand charge in the industry. IID is looking at ways to mitigate those issues. To the extent people have an onsite battery for residential to handle the air conditioning load, thus is the unlikelihood to be totally off the grid. Utilities must be creative and work together as they are confronting the same issues and IID does so through the California Municipal Utility Association.

Ms. Saleh commented that when one saves in energy, one hopes to save monetarily. With the charges that might be imposed, it certainly would reduce the amount saved. Ms. Asbury responded that it was understood.

Mr. Hernandez inquired about the backlog in rooftop solar [applications] and how many systems have been installed thus far. Ms. Asbury informed there is a very accurate number on the IID website, but recalled there are about 2,300 units and 39 MW of capacity installed on the IID system to date.

Ms. Evans reported information about the La Quinta inquiry on outages to advise the committee what is planned for 2016 and share additional information regarding recent events that occurred in the La Quinta area. In December, staff reported 37 outages within the perimeters that were inquired about. A majority of those outages were momentary, lasting less than five minutes. Those of a sustained nature were less, but they affected a significant number of customers. Staff provided a breakdown of those due to unknown causes and the car vs. pole, bird contacts and Mylar balloon contacts that affected the system in 2015.

Shortly after that information was presented, there was another outage Dec. 16, 2015, in which three substations were lost due to work on Avenue 42 Substation. IID does not have a direct tie to Jefferson Substation to help pick up load so a trip occurred during the process. It took the North La Quinta Substation out of service creating a two-hour outage affecting customers in that area. To mitigate that, staff changed the relay settings so the reaction time is a lot quicker in the future.

On Jan. 5, there was an overhead capacitor bank failure out of Shields Substation. That outage affected about 1,000 customers for about an hour.

On Jan. 20, there was a three-phase underground transformer failure that affected 78 customers. IID sent troubleshooters to find and isolate the problem; however, it takes quite a period of time to identify an underground failure, which was a contributor to the cause of that outage.

On Jan. 31 at Marshall Substation, troubleshooters are looking for the cause of the outage, which is unknown. Staff believes the heavy winds slapped lines together, which caused the trip; that outage lasted 54 minutes.

Going forward in 2016, there are definitely several circuits that can be targeted to improve reliability. There are about six miles of underground, open concentric cable along six circuits, which are primarily out of the three substations, North La Quinta, Northview and Jefferson. Staff is looking at building projects to replace as much of that cable as possible in 2016. Another problem is poles in the area that need to be replaced; about 60 poles have been identified in the pole replacement program in the same substations.

Staff is working with Distribution Planning & Engineering to analyze and prioritize a project that affects Northview Substation, which is exceeding its capacity under heavy summer loading conditions. The wire size that feeds into and terminates out of the substation is a smaller size. Staff would like to look at reconductoring that line to allow it to partially pick up circuits and take load off other substations. Staff is trying to tap into some of the funds that Mr. Montaño has identified to help fund these projects.

Mr. Osborne expressed thanks and appreciation as he had hoped staff would look into this. He then asked if staff could let the committee know at some point which projects they are looking at in their area to improve the system and its reliability. Ms. Evans replied that staff would be glad to do that.

Vice Chair Ramos Watson mentioned that a couple of years ago, she asked the district to look into the acquisition of the IID-owned [streetlight] poles on behalf of the city of Indio’s city council. About 50 percent are owned by the city and the remaining 50 percent by IID. Her council is making that request again and Indio’s new public works director, Mr. Tim Wassil, will contact Ms. Evans to move forward.

11. MEMBER COMMENTS

Ms. Saleh conveyed she asked the question about going off grid and the answer was that none of the current backup batteries would actually take people completely off-grid. Solar companies are selling these types of backup storage batteries for about $10,000. With IID's superior knowledge about such things, she thought it would be a great service to enlighten the public through public service announcements. She did not know whether IID feels that is its place or not, but the district is the most knowledgeable about all the problems with solar and electricity in the area.

Ms. Broughton announced the Riverside County Fair and National Date Festival takes place Feb. 12-21. It is probably the largest gathering of people that live in Coachella Valley that use IID power and pay bills. She hoped there will be even more cooperation and participation from IID in the future as it is an opportunity for the district to educate the people that live here as to what IID does, how to more efficiently use power and work together to meet these goals. It is a good opportunity and she hated to see IID miss it. Vice Chair Ramos Watson added that about 300,000 people attend.

Referring to Mr. Anderson's comments regarding the various projects being canceled, Mr. Osborne echoed his request pertaining to a look at the big picture and the use of that money for other projects. He looks forward to seeing that report at some point this year. He remarked it was a great idea from Mr. Anderson, who thanked Mr. Osborne.

Mr. Perez suggested the committee start meeting together and thought it would be best to meet in La Quinta next time. Chairwoman Gomez agreed and suggested meeting more frequently than annually. If that does happen, the [meeting location] will be alternating so the committee can hopefully work more in conjunction with each other. She would be looking into that and probably send information to the committee members.

12. NEXT MEETING

The next meeting will be held March 7, 2016, at 6 p.m.

13. ADJOURNMENT

There being no further business, Chairwoman Gomez adjourned the meeting at 7:40 p.m.

Attachment P-2

IID Energy Consumers Advisory Committee Meeting Minutes
from February 16, 2016

IID

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MINUTES OF REGULAR MEETING
TUESDAY, FEBRUARY 16, 2016

IMPERIAL IRRIGATION DISTRICT	BOARD OF DIRECTORS
William R. Condit Auditorium	Division 1—Matthew Dessert, *Vice President*
1285 Broadway Ave.	Division 2—Bruce Kuhn
El Centro, CA 92243	Division 3—James C. Hanks
	Division 4—Stephen W. Benson,
Kevin E. Kelley, *General Manager*	Division 5—Norma Sierra Galindo, *President*

MEETING CALLED TO ORDER—9:05 a.m.

PUBLIC COMMENTS
None.

CONVENE CLOSED SESSION

1. PUBLIC EMPLOYEE DISCIPLINE/DISMISSAL/RELEASE
   (Cal. Gov. Code sec. 54957(b))
2. CONFERENCE WITH LEGAL COUNSEL—EXISTING LITIGATION
   (Cal. Gov. Code sec. 54956.9(d)(1)):
   In re Order Instituting Rulemaking to Improve Public Access to Public Records Pursuant to the California Public Records Act, CPUC Rulemaking 14-11-001
3. CONFERENCE WITH LEGAL COUNSEL—EXISTING LITIGATION
   (Cal. Gov. Code sec. 54956.9(d)(1)):
   IID v. CAISO Case No. 15CV1576 AJB RBB
   United States District Court, Southern District of California
4. CONFERENCE WITH LEGAL COUNSEL—EXISTING LITIGATION
   (Cal. Gov. Code sec. 54956.9(d)(1)):
   In the matter of Imperial Irrigation District, etc., SWRCB Order 2002-0013
5. PUBLIC EMPLOYEE PERFORMANCE EVALUATION (Cal. Gov. Code sec. 54957(b)(1)): General Manager

RECONVENE OPEN SESSION—1:05 p.m.
The Pledge of Allegiance was recited.

REPORT OF ACTION(S) TAKEN IN CLOSED SESSION
General Counsel Ross Simmons announced that today, in closed session, a majority of the board voted to accept the decision of the hearing officer to uphold the termination of the employee with personnel No. 111848 for the reasons set forth in the hearing officer's decision and to approve the issuance of the notice of this action and the reasons therefor to the employee by the manager of Human Resources. As such the

employee with personnel No. 111848 is terminated effective July 30, 2015. Four directors voted to uphold the termination and Director Kuhn abstained.

PRESENTATIONS
The board recognized the Team of the Month for February 2016, made up of Facilities employees who assisted with 54 staff relocations throughout the district during the months of December and January:

Richard Beltran	Fermin Estrada	Pete Lizarraga
Victor Bustamante	Ruben Villegas	Eugene Paleo
Jose Amarillas	Mario Morales	Linda Garduño
Sara Cervantes	Adrian Miranda	Enrique Fuentes

Of the 10 employees scheduled to receive service awards for years of service to the Imperial Irrigation District, the following attended the meeting to be recognized by the board:

Bryan Stewart	Financial Accountant	10
Martin Zamora	Construction Resources Worker	10
Richard Palacio	Lineman Journeyman	15

APPROVAL OF AGENDA
Moved by Director Dessert, seconded by Director Kuhn, that the board approve the agenda, as submitted. Motion carried 5-0.

PUBLIC COMMENTS
Christian Lydick, El Centro, said that he wanted to bring to the attention of the board a very useful tool to help the Salton Sea and thereby improve the health of Imperial County as a whole, and that is the planting of bamboo. There are several potential benefits to this fast-growing plant. It can be used to convert poor or degraded lands to productive agriculture. It can be planted at close intervals to rebuild biomass. Bamboo can be useful in mitigating climate change. It can improve the environment in practical ways through soil stabilization, watershed management, soil remediation and can act as a biofilter. It also has economic value through cultivation and production of goods. And it could become an energy source, as well.

COMMENTS BY BOARD MEMBERS
Director Benson stated that he would be attending the annual Family Farm Alliance meeting in Las Vegas, February 18-19. He also mentioned that this past weekend there was an event at the Salton Sea and several hundred paddlers/kayakers participated. This was organized by the Indio/Coachella Chambers and other organizations that are focused on bringing activities back to the sea. It was well-received. He hopes that IID can get behind this event, which will probably become an annual occurrence.

Director Kuhn stated that a closed session was held on February 4, but during the open session, Ruben Casarez addressed the board. He was not happy since he lost his job; however, he said something that was repulsive to Director Kuhn. Mr. Casarez accused him, Director Dessert, Director Benson and Director Hanks of being in the Klu Klux Klan. Director Kuhn told the audience that in 2004 he was one of two recipients of the Martin Luther King Image award and this honor is not given to anyone who is in the Klu Klux Klan.

COMMENTS BY GENERAL MANAGER
None.

CONSENT

No. 1
Minutes

Moved by Director Dessert, seconded by Director Benson, that the board approve the minutes of the following meetings of the Imperial Irrigation District Board of Directors:

- January 4, 2016, regular
- January 19, 2016, regular
- February 2, 2016, regular
- February 4, 2016, special

Motion carried 5-0.

No. 2
Directors' expense repts

Moved by Director Dessert, seconded by Director Benson, that the board acknowledge receipt of the directors' expense reports for the period ending January 2016. Motion carried 5-0.

No. 3
Reject claims

Moved by Director Dessert, seconded by Director Benson, that the board reject the following claims for damages and instruct the secretary to the board to provide the statutorily required notice of denial to each claimant:

- Guerreros Meat Market & Bakery (No. 16354.1CE)
- Patrick Ryan (No. 16392.1CE)
- Alexandra Carmichael Weit (No. 16344.1CE)

Motion carried 5-0.

No. 4
SCGC easement

Moved by Director Dessert, seconded by Director Benson, that the board approve the issuance of a grant easement to Southern California Gas Company of 22,750 square feet near its current regulator station at Blair and Young roads. Motion carried 5-0.

No. 5
Warrants report

Moved by Director Dessert, seconded by Director Benson, that the board acknowledge receipt of the accounts payable checks and wires report for January 2016, as presented by the chief financial officer. Motion carried 5-0.

No. 6
District Pump 20

Moved by Director Dessert, seconded by Director Benson, that the board approve Major Work Authorization No. 100401 to replace existing District Pump 20 seepage interceptor as it is no longer capable of controlling seepage recovery from the East Highline Canal and is impacting adjacent farmlands. The cost of the project is $512,700. Motion carried 5-0.

No. 7
District Pump 21

Moved by Director Dessert, seconded by Director Benson, that the board approve Major Work Authorization No. 100371 to replace existing District Pump 21 seepage interceptor, as it is no longer effective in controlling seepage recovery from the East Highline and adjacent farm grounds are being impacted. The cost of the project is $450,900. Motion carried 5-0.

No. 8
ColGreen North Shore

Moved by Director Dessert, seconded by Director Benson, that the board approve a 10-year transmission agreement with ColGreen North Shore, LLC, to serve its 75-megawatt generating facility in Riverside County that has a commencement date of January 1, 2017. IID will collect about $663,000 in annual revenues once the credits associated with the network upgrades constructed in connection with the agreement are exhausted. Motion carried 5-0.

ACTION

No. 9
Weed spray contract

At the board meeting of January 4, 2016, Mike Pacheco, water manager, reported that IID had conducted a third bid process to solicit weed spray services for a 3.5-year-term (through 2019) for the northern and/or southern regions and three qualified companies submitted cost proposals. Eynon Management, Inc., the incumbent contractor, submitted the lowest bid of $2,440,387/year for both regions. The scope of service includes IID's water service area, as well as the managed marsh and IID/MWD conservation program sites.

At the January 19, 2016 board meeting, Al Kalin, chairman of the Water Conservation Advisory Board, stated that the WCAB had recommended that clean water, and not canal water, be used to spray. Mr. Pacheco stated that staff did some testing using city water versus canal water and the results were the same.

No. 9 contd

It was noted that Water Department staff and Farm Bureau have identified and confirmed locations throughout the IID service area that will provide clean water to be used instead of canal water as recommended by the chemical labels and representative of the company producing the chemical and the University of California Research Center and University of California Davis weed control expert.

Director Benson asked if this would preclude staff from doing in-house spraying if there are areas of concern and the answer was no; staff is open to other alternatives, especially in large drains that are near other waterways.

Moved by Director Dessert, seconded by Director Benson, that the board approve and authorize staff to issue a three-and-a-half year service agreement in the amount of $8,541,355.21 to Eynon Management, Inc., to cover the Imperial Irrigation District's 2016-2019 weed spray program. Motion carried 5-0.

No. 10
IID/County MOU re Salton Sea

At the February 2, 2016 board meeting, General Manager Kelley presented an amendment to the memorandum of understanding between the district and Imperial County concerning Salton Sea stabilization and restoration to dispel the notion that a surcharge should be imposed on renewable energy development in that area. For that reason, IID would pledge the use of its lands and mineral assets in the known geothermal resource area to further stabilization and restoration activities. IID would have an open season for potential developers to bid for development of renewable energy projects in order to create a public-private partnership that would become a component of the Salton Sea program. Mr. Kelley had stated at that meeting that staff was removing any reference to an out-of-market surcharge from the original MOU and the issue will be on the next agenda for action by the board.

At this meeting, Joanna Smith Hoff, assistant counsel, stated that this issue was on the county's information agenda on February 2, but since it does not meet today, it will be on next week's agenda. In between February 2 and what's included in today's packet, the amendment was refined to make it more direct in its intent—clarify that there was no intention to include a surcharge on renewable energy. The fifth recital from the original MOU was removed and the following sentence added: "County and IID do not support a surcharge on Renewable Energy for restoration of the Salton Sea."

No. 10 contd

Linsey Dale, Imperial County Farm Bureau, stated that the there's a line that states the district pledges the use of land and mineral assets in the known geothermal resource area and Farm Bureau has some concerns with this language. IID might be giving up mineral rights or potential royalties, which it feels are due the Water Department.

Mr. Kelley said that it was explicitly understood that the pledge of land and minerals was confined to use only and that nothing would undermine the legitimate rights of the Water Department from the development of those lands.

Director Hanks indicated that he would like to see that language modified to reflect exactly what needs to be said. The language regarding the pledge is read differently by each reader.

Mr. Kelley responded that perhaps a parenthetical could be added, right after the pledge language, that stipulates, "not including royalties or lease payments."

Director Hanks went on to state that the surcharge issue was brought forward when the IID was pushing for a carve-out for the geothermal development and part of that carve-out would be a surcharge to help with the sea. This was pushed through to the final vote and under threat of veto by the governor, it went south. He is pleased that this language is being removed. It was an effort from IID to assist the state in meeting its obligation and it put its foot on the back of our necks.

Moved by Director Benson, seconded by Director Dessert, that the board approve *Amendment No. 1 to the Memorandum of Understanding Between the County of Imperial, Imperial County Air Pollution Control District and Imperial Irrigation District Concerning Slaton Sea Stabilization and Restoration*, with the following change under Section B: "IID pledges the use of its land and mineral assets *(not including royalties or lease payments)* in the KGRA and the area around the Salton Sea for Renewable Energy development to further Salton Sea stabilization and restoration activities. Motion carried 5-0.

No. 11
ECA
proposal

The proposal by Chief Financial Officer Belen Valenzuela called for the board to postpone the transfer of $16 million from the rate stabilization fund in 2016 to another year and credit customers the energy cost adjustment over-collection from 2015 of $24.6 million,

No. 11 contd

which equates to $0.0073 per kilowatt-hour. She indicated that the energy and ECA rates, even without the RSF transfer in 2016, are projected to be lower than in 2015.

When asked the total left in the RSF, the CFO indicated that there's still $67 million in that fund as of January 1, 2016. She pointed out that she plans to start contributing to the other post-employment benefits (OPEB) that have been accruing since 2007. She also wants to build up district cash reserves. General Manager Kevin Kelley said that the CFO is not asking to change the board policy, but only to defer the transfer of $16 million by no more than a year.

Some of the directors indicated they would like staff to come up with another designation for the rate stabilization fund.

Director Hanks stated that some ratepayers that funded this over-collection are no longer alive and will not benefit from any refunds. He added that there has been a consistent over-collection for some time and he is just trying to keep track of it.

Director Benson pointed out that half of the over-collection was created between July-September and wondered if it would be refunded proportionally.

Moved by Director Benson, seconded by Director Dessert, that the board authorize the chief financial officer to credit customers the energy cost adjustment over-collection from 2015 of $24.6 million, which equates to $0.0073 per kilowatt-hour and move the $16 million from the rate stabilization fund and placed it in another restricted account (i.e. OPEB account). Motion carried 4-1, with Director Hanks voting no.

No. 12
Local Entity

On December 8, 2015, the board approved 1,367 claims for the 2014 non-competitive program and directed the Local Entity staff and subcommittee to initiate the appeal process for the balance of the claims. This program had $7,984,063 of available funding that was distributed as follows:

2011-12 $1,993,140 *2012-13* $2,949,959 *2013-14* $3,040,964

Since enough funds were available, there was no proration to pay all approved claims in their entirety, using the per-applicant cap of $100,000.

No. 12 contd

Due to comments from constituents who had been capped on previous years, Director Benson brought up the cap and suggested that the board might consider removing it. Farm Bureau does not support this position, he said. If this is not amenable, perhaps any remaining funds could be distributed on a prorated basis to those affected by the cap.

Director Kuhn stated that staff had calculated disbursements using the $100,000 cap and, if it's removed, then all the formulations would have to be changed. In the best interest of this entity, the funds should be disbursed as recommended by staff and look at the cap issue next year.

Director Hanks asked that this issue be acted upon with two motions. One is to accept the recommendations of the Local Entity staff up to this point so the funds can be released and the second would deal with disposition of any remaining funds.

Carson Williams with Sun Valley Hay stated that he has had discussions with other colleagues in the industry and with some of the board members about the unfair situation of the cap. He requested that the Local Entity staff provide an alternative on how the funds would be paid out if there were no cap.

Director Kuhn indicated that this is not a God-given gift. The Local Entity was created to equitably reimburse/offset some of the financial impacts to landowners affected by the fallowing program.

General Counsel Simmons pointed out that, from a Brown Act perspective, the issue is whether there will be a disbursement of funds or not. When there's a discussion of a separate vote, then the board is going to a different topic, which is not listed on this agenda. He recommended that the board take the matter before bringing back the disposition of the cap at a future meeting.

Brian Napier, from Seeley, agreed with Mr. Williams and suggested that the board vote no on this issue because there's inequality between small and large companies. A larger employer should not be penalized. He asked that the board remove the cap or come back with a twofold agenda item to address both the cap and distribution of remaining funds.

No. 12 contd

Mr. Williams again spoke to the board at length about his company, Sun Valley Hay, how long it's been in business and how much it has lost because of the cap. He said that the program is unfair to larger companies and, if the cap were removed, Sun Valley Hay would probably receive double what it is scheduled to receive.

Linsey Dale, Imperial County Farm Bureau, stated that the Farm Bureau's position is that any remaining funds be put toward system conservation, rather than its current program.
Kay Day Pricola with COLAB said that the Local Entity is fraught with problems. Its intent was good, but COLAB is concerned that there are some folks who have taken the loopholes and moved forward to gaming the program. Infrastructure is needed, whether it's system conservation or in other areas, to attract and generate new businesses.

Moved by Director Kuhn, seconded by Director Dessert, that the board approve the 49 applicants listed on a worksheet provided by Local Entity staff, with recommended disbursement mitigation payments totaling $6,292,391.23 from the Local Entity 2014 non-competitive mitigation program, and address the issue of remaining funds and method of distribution at a future meeting. Motion carried 4-1, with Director Benson voting no.

Director Benson asked that staff bring back a proposal of how remaining funds need to be distributed and suggested it be done proportionally. Director Hanks recommended that staff should keep it year-to-year and those who have capped out should submit the documentation to staff. If there are sufficient funds, it should not exceed the percentage paid to those who failed to reach the cap. Those who did not appeal because of the cap, can go ahead now and submit their documentation.

No. 13
Energy summit

Moved by Director Benson, seconded by Director Dessert, that the board fund the 9th Annual Imperial Valley Renewable Energy Summit in the amount of $25,000 from funds included in the Energy Department budget. Motion carried 5-0.

No. 14
Calif Farm Water Coalition

Moved by Director Benson, seconded by Director Hanks, that the board approve payment of the Imperial Irrigation District 2016 dues to the California Farm Water Coalition in the amount of $67,500, which funds are included in the Water Department budget. Motion carried 5-0.

No. 15
Farm Smart

Moved by Director Hanks, seconded by Director Benson, that the board continue support of the Farm Smart program for 2016 by funding the amount of $50,000; this amount is included in the Water Department's budget. Motion carried 5-0.

No. 16
Purchase vehicles

No. 16 contd

Moved by Director Dessert, seconded by Director Benson, that the board authorize staff to issue purchase orders to the following vendors for various pieces of equipment, as noted, with applicable taxes to be added when the order is issued:

PRFP No. 1171: Four trucks	Sunroad Auto LLC Dba Kearny Pearson Ford	$159,952
PRFP No. 1172: One truck	Bill Alexander Ford	$50,936.26
PRFP No. 1174: Digger derrick	Altec Industries	$290,066

Motion carried 5-0.

No. 17
Cancel IV Sub to Dixieland

At the regular board meeting of February 2, 2016. Jesse Montaño told the board, that after a thorough assessment of the Imperial Valley Substation to Dixieland 230-kV interconnection project, staff recommends it be cancelled. Of the original $11.4 million budgeted for both phases, only $3.85 has been spent, leaving undisbursed funds of $7.54 million.

Moved by Director Dessert, seconded by Director Galindo, that the board approve the cancellation of Major Work Authorization No. P-6574 and Project No. 100571, covering the Imperial Valley Substation to Dixieland 230-kV interconnection project. Motion carried 4-0-1, with Director Kuhn abstaining.

No. 18
Cancel S Line project

At the February 2, 2016 regular board meeting, Jesse Montaño indicated to the board that, after careful evaluation, staff was recommending the cancellation of the S Line 230-kV transmission line project, which consists of rebuilding the existing circuit from El Centro to Imperial Valley Substations from wood structures to a double circuit line with steel poles, at a cost of $2.6 million. Expenditures to date are $1.6 million, leaving an undisbursed amount of $836,943.

Moved by Director Dessert, seconded by Director Hanks, that the board approve the cancellation of Major Work Authorization No. P-6713 related to the S Line 230-kV transmission line project. Motion carried 4-0-1, with Director Kuhn abstaining.

INFORMATION

No. 19
Internal compliance review

The district's internal compliance program requires an annual review and board approval of any changes. Tino Zaragoza, reliability compliance officer, indicated that a few minor changes were made and Section 6.6 was added as follows:

"Standard Owners
Standard Owners have overall responsibility and authority for leading and managing the implementation of, and adherence to, the Reliability Standards."

No. 20
Policy No. 1080 re MWAs

With the decentralization of the Portfolio Management Office, Policy No. 1080 covering major work authorizations, has been revised to define the roles and responsibilities of staff as it relates to the MWA process. The proposed policy has been streamlined to three pages, with a new standard operating procedure proposed delineating the roles and responsibilities. Betty Voroveanu, chief internal auditor, reviewed the changes.

No. 21
WCAB update

Larry Cox, representing Al Kalin, chairman of the Water Conservation Advisory Board, reviewed actions taken during its meeting on February 11, 2016. Ben Brock reported that there are almost 10,000 AF of water available in the clearinghouse. Merlon Kidwell stated that the volume for the 12-hour run program doubled since 2005 to 20015, from 31,000 AF to over 60,000 AF and there's a definite concern when the fallowing program ends in January 2018—the impact of not being able to use the rejected 12-hour run water for mitigation, which will impact IID and the farm community markedly. The WCAB created a 12-hour run subcommittee.

No. 22
WD gen. matters

Tina Shields and Mike Pacheco, water managers, provided the following report:

(1) As of February 8, 2016, IID has received about 1,200 proposals for the current on-farm conservation program and nearly 1,400 proposals for the next application period.
(2) As of today, the estimate of IID's underrun is -35,000 AF.
(3) Staff continues to finalize 2015 conservation yields. Preliminary data indicates that in addition to its 2015 conservation and transfer requirements, IID conserved and pre-delivered to the Salton Sea about 44,000 AF of its 2016 mitigation obligation and conserved over 46,000 AF of water for storage purposes.

No. 22 contd

(4) IID has delivered 23,390 AF of the 130,000 AF 2016 obligation for Salton Sea mitigation.
(5) The State Water Resources Control Board reported that Californians have reduced water use by 25.5 percent since June 2015, conserving nearly 1.1 million acre-feet to date. The emergency water conservation regulations have been extended through October 2016, but with modifications.
(6) Divisions are reporting an average of 185 12-hour water orders for 700 cfs.
(7) The East Highline Canal is running 1150 cfs, Central Main Canal 600 cfs, and Westside Main Canal 700 cfs.
(8) The North Date pipeline project, in front of the former Sears site, will begin next week. This is a joint effort with the city of El Centro.
(9) On the Imperial Dam electrical project upgrade, lead was found in the galleries, probably from paint (galleries are 75 years old), which will use the contingency allotted in the original major work authorization. Also, the four rollers being replaced at Imperial Dam are more damaged than anticipated.
(10) All permits have been obtained, and a controlled burn at the Managed Marsh will occur this Thursday, weather permitting.

Related to on-farm electrical projects, Director Benson asked if there was any progress in setting up a fund for people that utilize that backfeed money. Mr. Pacheco said that he and Ms. Shields have forwarded some criteria they developed to the energy manager and chief financial officer for their input. Afterward, the issue will come before the board for its consideration.

No. 23
System conservation plan

Vince Brooke, interim general superintendent, provided a summary review of the system conservation plan implementation efforts as staff and landowners transition from fallowing-based conservation to on-farm and delivery system efficiency-based measures. He indicated that some projects have been completed and others are in concept, design and construction phases. The ultimate goal is to conserve at least 103,000 acre-feet of on-farm water by 2026. Staff has been focusing on seepage recovery, lateral interties, a discharge reduction program and main system and mid-lateral reservoirs. Staff does not close the door to other measures proposed by growers/landowners if they can be accommodated and result in water savings. Mr. Brooke reported that 22 seepage recovery pump stations and three lateral interties had been completed.

No. 23 contd

Directors Dessert, Kuhn and Galindo are interested in touring a wellpod development that the U. S. Bureau of Reclamation is doing in Arizona.

No. 24
Oldcastle

Francisco Peña, water general superintendent, indicated that the current multi-year agreement with Oldcastle Precast for the supply of concrete structures, risers and walkways for capital/county projects needs additional funding in the amount of $250,000 for 2016. This amendment will bring the total cost of the agreement to $750,000.

No. 25
Energy Dept.
gen. matters

Vicken Kasarjian, energy manager, provided the following report:

(1) At the January 19 board meeting, Director Dessert inquired whether IID had an active remedial action scheme in service on its system, and it does not.
(2) On January 28, 2016, IID staff and Directors Kuhn and Dessert held a second meeting with representatives of the Comision Federal de Electricidad and are scheduled to meet again on Friday, February 12, to review and finalize technical details.
(3) Attended a Large Public Power Council meeting in Orlando, Florida on February 6-8, 2016.
(4) Mr. Kasarjian, along with Antonio Ortega, attended the California Municipal Utilities Capitol Day function on February 8, 2016.
(5) CalEnergy is aggregating generation from its plants into a portfolio. Energy staff has worked with it to accommodate the portfolio concept. The portfolio necessitated amending and restating existing transmission service agreements to accommodate the aggregation. In addition, CE has agreed to fund any necessary reconfigurations required to IID's energy management system to accommodate the aggregation. In order to allow CE to fulfill its power purchase agreement obligations with Salt River Project, staff executed the necessary agreements.

No. 26
D Line relay
protection

Lucy Arias, energy project manager, reviewed Major Work Authorization No. 100643, covering the replacement of relay protection equipment on the D Line from Pilot Knob to Knob substations. The estimated project cost is $267,800. It has been determined that for the purpose of complying with the California Environmental Quality Act, a notice of exemption will be filed with the county of Imperial.

No. 27
Niland Sub. amendment

Jesse Montaño told the board that when it approved Major Work Authorization No. 100443 on June 10, 2014, staff at that time had recommended replacing the existing 75-MVA with a 225-MVA transformer to accommodate future expansion at the Niland Switching Station. However, upon further review of the project, current staff now recommends that this transformer be replaced with a smaller 125-MVA unit, which had originally been suggested by the system impact study.

At this meeting, the board was told that a 125-MVA transformer currently at the Avenue 58 Substation can be removed without impact to the district system and installed at the Niland Switching Station.

RECONVENED CLOSED SESSION—5:08 p.m.
PUBLIC EMPLOYEE PERFORMANCE EVALUATION (Cal. Gov. Code sec. 54957(b)(1)): General Manager

REPORT OF ACTION(S) TAKEN IN CLOSED SESSION
None.

ADJOURNMENT—5:40 p.m.

Attachment Q

ECA Terms and Conditions

SINGLE RESOLUTION EXHIBIT Number RES/1174/2016

TERMS AND CONDITIONS FOR THE PROVISION OF STORAGE SERVICE

FILED BY

ENERGíA COSTA AZUL, S. DE R.L. DE C.V.

WITH THE

ENERGY REGULATION COMMISSION

[Approved December 16, 2016]

CONTENTS

SCOPE AND APPLICABILITY

Energía Costa Azul, S. de R.L. de C.V. owns a facility located in Baja California, Mexico, for the reception, storage, and delivery of LNG. ECA provides Storage Service for Shippers by receiving LNG at the inlet to its LNG regasification storage and regasification facility and delivers the resulting Natural Gas to Shippers at any authorized Send-Out Point.

The facility includes marine receiving facilities for 70,000 to 250,000 cubic meter vessels, with storage facilities expandable to four 160,000 cubic meter full containment storage tanks and a vaporizer system, expandable up to 73.7 million Standard Cubic Meters per day withdrawal capacity.

The purpose of these General Terms and Conditions is to establish the minimum conditions to be met by ECA in providing the Storage Service. These General Terms and Conditions are an integral part of the permit and will apply to all Storage Services provided under the Service Agreements.

These General Terms and Conditions for the Provision of the Service shall apply to and govern the provision of Storage Service only to Shippers who execute Service Agreements acceptable to ECA after consideration of ECA's commitments to others, the capacity of its System, and the other conditions to service set forth herein.

Any modification to these General Terms and Conditions shall require the review and approval of the Commission.

These General Terms and Conditions will be available on the Electronic Bulletin Board.

Unless otherwise defined herein or that based on the grammatical rules, the terms defined shall have the meanings attributed to them in Section 1 of these General Terms and Conditions.

GENERAL TERMS AND CONDITIONS

The following General Terms and Conditions are applicable to all services provided herein:

1. DEFINITIONS

1.1 **“Applicable Legal Provisions”** shall mean all the legal and regulatory provisions relating to Natural Gas, including the Regulation of the Regulatory Sector of Constitutional Article 27 in the Petroleum Branch, the Hydrocarbons Law, the Coordinated Energy Regulators' Law, the Official Mexican Standards relating to Natural Gas, the CRE Directives, as well as the civil and commercial legislation of Mexico, where applicable, as modified or superseded from time to time.

1.2 “**Arrival Buoy**” shall refer to the usual anchoring and waiting points, located outside of the System and separate from the Marine Installations.

1.3 “**Available Capacity**” shall refer to the capacity of the System, expressed in Gigajoules, that has not been contracted for Firm Storage Service. The Standard CV shall be used as the conversion factor to determine Gigajoules.

1.4 “**Available Stored Quantity”** or “ASQ" shall refer to the Quantity of LNG, expressed in Gigajoules, held by ECA in Storage on the Shipper's account at any time. The Standard CV shall be used as the conversion factor to determine Gigajoules.

1.5 “**Availability Notice**” shall refer to the notice given by the Shipper's vessel to ECA to confirm its arrival at the Arrival Buoy, that it has received all the harbor authorizations necessary and is ready to transfer the cargo on arriving at the jetty

1.6 “**Boil-Off of LNG**" gas shall refer to the low-pressure gas that (i) boils off from ECA's storage tanks and other System installations, and (ii) flashing from the liquid phase to the gaseous phase during unloading or loading of Shipper's LNG.

1.7 **“Business Day"** shall mean Monday through Friday from 08:00 to 17:00 hours, Northwestern Time, excluding any day(s) on which Mexican credit institutions are closed to the public.

1.8 “**Change in the Law**” shall refer to the enactment, publication, effective date or the application of any law, regulations, rule, ordnance, directive or other legal standard or any change in the interpretation or application of same (including but not limited to any environmental or fiscal standard) issued by any Governmental department or authority, court, tribunal, public body or any other Mexican Government entity, whether Federal, State or Municipal.

1.9 **“Commission"** or **"CRE"** shall refer to the Energy Regulation Commission, which is the decentralized agency of the Ministry of Energy of the United Mexican States, and any other authority that replaces it.

1.10 “**Confirmed Delivery Window”** means each Delivery Window allocated to a Shipper as part of a Delivery Program issued by ECA pursuant to these General Terms and Conditions.

1.11 “**Contractual Year**” shall refer to, with regard to any Service Agreement, a period of twelve (12) consecutive months from the commencement date of the Storage Services under said Service Agreement and each anniversary of said date.

1.12 “**Conventional Tariff”** shall mean the tariff agreed freely by Shipper and ECA for the rendering of the services in accordance with the Prices and Tariffs Directive.

1.13 **"Credit Rating Agency"** shall refer to an internationally recognized global credit rating, research and risk analysis firm, publishing credit opinions, research and ratings on fixed-income securities, issuers of securities and other credit obligations.

1.14 “**Day**” shall refer to the period of twenty-four (24) consecutive hours starting at 00:00 hours Northwestern Time.

1.15 “**Delivery Schedule”** means the schedule of Confirmed Delivery Windows at the Terminal for a Shipper, and all Unscheduled Delivery Windows in a relevant period, as established, updated, amended, modified and supplemented in accordance with the terms, conditions and procedures set forth in these General Terms and Conditions.

1.16 **“Delivery Window"** shall mean the thirty-six (36) hour window period during which the Shipper’s Vessel is to arrive and either unload or load its LNG cargo at the Reception Point, unless ECA and the Shipper agree another period.

1.17 “**Directives**” shall refer to the general provisions applicable to regulated activities involving Natural Gas issued by the CRE such as the criteria, guidelines or methodologies used to regulate first-hand sales and gas transport, storage and distribution activities.

1.18 **"Draft Delivery Schedule”** means the schedule of Delivery Windows proposed as Confirmed Delivery Windows as established, updated, amended, modified and supplemented in accordance with the terms, conditions and procedures set forth in these General Terms and Conditions.

1.19 " **ECA**” shall refer to the Permit Holder.

1.20 **“Electronic Bulletin**” shall mean the remotely accessible information platform on which ECA publishes information to the general public as required by Applicable Legal Provisions and on which the Shippers perform the operations related to the services being rendered under these General Terms and Conditions.

1.21 **"Electronic Funds Transfer"** shall refer to payments made by wire transfer (interbank transfer, Clearing House Interbank Payments System (CHIPS) or account deposit), Automated Clearing House (ACH) or any other recognized electronic or automated payment mechanism agreed by the Shipper and ECA in writing.

1.22 **“Excess Charge"** shall be the charge payable by Shipper if its Available

Stored Quantity exceeds its MSQ or the actual Quantity of Gas withdrawn by a Shipper exceeds such Shipper's MDQ for any Gas Day in a given Gas Month, as more particularly set forth and calculated in the Regulated Tariff Sheet (for Shippers paying the Regulated Tariff) or the Service Agreement (for Shippers paying a Conventional Tariff).

1.23 **"Extension**" shall refer to any increase in the Maximum Guaranteed Quantity that requires prior authorization of the CRE.

1.24 **"Financial Guarantees"** are the financial instruments through which the Shipper guarantees to ECA that it will be able to perform the obligations established in these General Terms and Conditions and the Service Agreement

1.25 **"Firm Base Storage Service"** or **"FBSS"** shall mean the Storage Service that is not subject to restrictions, reductions and interruptions, except in the cases provided for in these General Terms and Conditions.

1.26 **"Gas**" or "**Natural Gas"** is the mixture of hydrocarbons composed mainly of methane.

1.27 **"Gas Day"** shall mean a period of twenty-four (24) consecutive hours beginning and ending at 07:00 hours, United States Pacific Time. The reference date for any Gas Day shall be the date of the beginning of said Gas Day.

1.28 **"Gas Month"** shall refer to the period beginning at 07:00 hours United States Pacific Time on the first Gas Day of the Month and continues through the end of the last Gas Day of the Month.

1.29 "**Gigajoule**" or "**GJ**" shall refer to one billion Joules.

1.30 "**General Terms and Conditions"** shall mean these General Storage Services Terms and Conditions**.**

1.31 "**Governmental Authority"** shall mean any government body of the executive branch, at Federal, State or Municipal level, including any ministry, department, directorate, agency, commission or tribunal as well as any authority with legislative or judicial power at Federal or Local level.

1.32 **“Information System”** shall refer to all the information technology and telephony media provided by ECA to Shippers in order to send and receive information about the rendering of the Storage Service.

1.33 **"Insolvency"** or **“Insolvent”** shall refer to any party that

(i) generally does not perform its payment obligations, in accordance with Article 11 of the Mexican Commercial Bankruptcy Law;

(ii) is unable to pay its debts as they fall due;

(iii) requests or permits the appointment of an auditor, supervisor, receiver or administrator to manage said party or any of its assets or makes a general assignment to its creditors;

(iv) without requesting it, receive the appointment of an auditor, supervisor, receiver, administrator, mediator or other custodian for such party or for a substantial part of its assets and said auditor, supervisor, receiver, administrator, mediator or other custodian is not removed by the tribunal within the following sixty (60) days;

(v) is subject to, permits or receives the commencement of any bankruptcy, insolvency, reorganization, debt restructure or other procedure in accordance with the Mexican Bankruptcy Law (or any law that replaces it) or any dissolution, winding-up or liquidation proceeding of said party and, if said procedure is not commenced by such party, is consented to or acquiesced in by said party or results in a resolution, appointment, declaration or proceeding that remains active for sixty (60) days; or

(vi) takes any corporate action authorizing, or in furtherance of, any of the foregoing.

1.34 **"Interference"** shall refer to, with respect to a Shipper that proposes (i) a change to the date of its Confirmed Unloading Window or (ii) a material change in the quantity or quality of LNG to be unloaded during a Confirmed Unloading Window, where such change would reasonably be expected to prevent or delay another Shipper's from mooring or unloading a cargo in its Confirmed Unloading Window, as determined by ECA pursuant to Clause) 4.4(D) of these General Terms and Conditions.

1.35 **"Interruptible Base Storage Service"** or "**IBSS**" is (i) the Storage Service that is subject to restrictions, reductions and interruptions in order to provide the FBSS, and (ii) the delivery of Gas to IBSS Shippers in Quantities that exceed said Shippers' MDQs, provided that said deliveries are subject to the terms and conditions of their respective Service Agreements, as well as to restrictions, reductions and interruptions in order to provide the FBSS under the terms of Section 2.2.2 and any other provision of these General Terms and Conditions.

1.36 **"Irrevocable Standby Letter of Credit"** shall refer to the irrevocable standby letter of credit issued by a credit institution or bank with a credit rating of AA or higher by Standard & Poor's or equivalent or higher by all other Credit Rating Agencies that rank such institutions.

1.37 "**Liquefied Natural Gas**" or "**LNG**" is natural gas in a liquid state.

1.38 **"Loading Services"** shall refer to the additional services provided by ECA to Shipper for the loading of an LNG cargo onto a Shipper's Vessel, including the handling of any additional vapor as a result of loading activities. The "Loading Services" shall include Shipper access to two additional Delivery Windows for each cargo loaded.

1.39 "**Marine Installations"** shall refer to the fixed installations consisting of the breakwater, jetty, mooring and other facilities for mooring navigation, necessary to secure Shipper's Vessel to the LNG transfer arms to transfer LNG. The "Marine Installations" shall also include the jetties for tugs and line boats, but shall not include tugs or line boats themselves.

1.40 "**Maximum Daily Delivery Quantity**" or "**MaxDDQ**" is the maximum Quantity of Natural Gas, expressed in Gigajoules, that Shippers can request for delivery on any Gas Day at a Uniform Hourly Rate in accordance with these General Terms and Conditions. The MDQ shall be set out in the Service Agreement between ECA and Shipper but cannot exceed eighteen point eight, five, eight, six, two percent (18.85862%) of the MSQ. The Standard CV shall be used as the conversion factor to determine Gigajoules.

1.41 “**Maximum Guaranteed Capacity”** is the total storage capacity expressed in Gigajoules that the System is able to provide under FSS Service Agreements. The Standard CV shall be used as the conversion factor to determine Gigajoules.

1.42 “**Maximum Storage Quantity”** or **“MSQ”** is the maximum Quantity of LNG, expressed in Gigajoules, specified in the Service Agreement, that ECA is obliged to store at the System for the per subject to the terms and conditions of these General Terms and Conditions and the Service Agreement.

1.43 “**Mexican Peso”** shall refer to the legal tender of Mexico.

1.44 **“Mexico”** shall refer to the United Mexican States

1.45 “**Minimum Daily Delivery Quantity”** or **“MinDDQ”** is the minimum quantity of Natural Gas, expressed in Gigajoules, stipulated in the Service Agreement that Shippers are obliged to withdraw on any Gas Day at a Uniform Hourly Rate. The Standard CV shall be used as the conversion factor to determine Gigajoules. The MinDDQ for any Gas Day shall vary depending on if a Shipper’ vessel loads or unloads on said Gas Day. Withdrawals of the MinDDQ shall be required as long as the Shipper has Available Stored Quantity.

1.46 **“Minimum LNG Inventory”** shall refer to an obligation of a Shipper or Shippers that has or have requested Loading Services during a Scheduling Year to maintain a minimum ASQ of twenty thousand (20,000) cubic meters as a whole during each Day of the Scheduling Year.

1.47 “**Month"** shall refer to the period beginning the first Day of the calendar month and ending at the start of the first Day of the next calendar month.

1.48 **“Negligence”** means a lack of diligence, whether related to an act or an omission, in which a person does not use reasonable means required under the circumstances to avoid or prevent any type of loss, cost or damage to itself or to another person. For the purposes of these General Terms and Conditions, if one party is required to indemnify the other, except for said other party’s negligence, and the party to be indemnified has in fact been negligent, then the indemnifying party shall not be exempt from liability, but instead the indemnifying party’s liability shall be reduced in the proportion of the loss or damage that was incurred due to the negligence of the party to be indemnified.

1.49 **"Northwestern Time"** or **“NT”** shall mean, in accordance with the Mexican Time System Law, the time on the 120 west meridian, which covers the state of Baja California.

1.50 **“Official Mexican Standard"** or **"NOM"** shall refer to the obligatory technical regulation issued by the respective authorities.

1.51 “**Operational Capacity”** shall equate to Maximum Guaranteed Capacity except when the System’s equipment maintenance interferes with ECA’s capacity to render that level of service.

1.52 **“Operational Flow Order"** or **"OFO"** shall refer to the notice sent to the Shipper in which ECA restricts transfers of LNG or deliveries of Natural Gas and/or communicates the need for the Shipper to remove all or part of the Available Stored Quantity from the System.

1.53 **“Open Season”** shall mean the process conducted by ECA pursuant to which Shippers submit FBSS requests for evaluation by ECA in accordance with Section 18 of these General Terms and Conditions in order to assign the Available Capacity among said requests.

1.54 “**Order**” refers to the communication sent by the Shipper to ECA indicating the Quantity of LNG required to be discharged and stored or vice versa. Conversely, it refers to the communication sent by the Shipper to ECA indicating the Quantity of Gas required to be delivered, as well as the Gas Day or Gas Month in which said service is required.

1.55 **“Permit**” refers to Natural Gas Storage Permit Number G/140/ALM/2003.

1.56 “**Prices and Tariffs Directive”** shall refer to the Regulated Natural Gas Activities Tariffs Determination and Price Transfer Directive (DIR-GAS-001-2007), published by the CRE in the Federal Official Gazette on December 28, 2007, with its respective amendments.

1.57 “**Punctual Arrival**” shall refer to the arrival of the Shipper’s vessel at the Arrival Buoy and the sending of the Availability Notice with sufficient time to allow the Shipper’s vessel to moor, load or unload and embark from the jetty on concluding its Delivery Window.

1.58 **“Quantity**" or "**Quantities**" shall refer to the number of units of Gas or LNG expressed in Gigajoules.

1.59 **“Reception Point**" refers to the point where the System's LNG transfer arm connects with the Shipper's vessel.

1.60 **“Regulated Tariff”** shall refer to the tariffs approved by the CRE for the rendering of the service billed to Shippers by ECA.

1.61 **“Regulated Tariff Sheet”** shall refer to the document included in these General Terms and Conditions that contains the list of Regulated Tariffs.

1.62 **"Scheduling Conflict”** means a situation in which ECA decides that: (i) a Shipper has proposed to move one of its Confirmed Delivery Windows onto another Shipper's Confirmed Delivery Window; (ii) two or more Shippers have proposed moving their Confirmed Delivery Windows into the same Delivery Window; or (iii) the change requested to a Confirmed Delivery Window would interfere with another Shipper or would result in a Terminal Limitations Determination.

1.63 **“Scheduling Representative”** shall refer to a person appointed to represent a Shipper in the scheduling matters described in these General Terms and Conditions and other operational issues that may arise from time to time in transfers of LNG at the Terminal.

1.64 **"Scheduling Year”** shall mean a twelve (12) month period commencing on April of a year and ending on March 31 of the next year.

1.65 **"Send-Out Point"** refers to the limit of ECA's installations, with regard to the interconnection between ECA's installations and the transportation pipeline of the Shipper or the party appointed thereby.

1.66 "**Service Agreement"** shall mean the agreement signed by the Shipper and ECA for the Provision of Storage Service through the System.

1.67 **"Service Application"** shall refer to the form attached to these General Terms and Conditions to be completed in full by the Shipper in order to request the Storage Service.

1.68 "**Shipper"** shall mean the entity that has entered into a Service Agreement to use ECA's Storage Services or has requested the Storage Services from ECA, in both cases, pursuant to these General Terms and Conditions and the Applicable Legal Provisions.

1.69 **"Shipper's Information Package"** shall refer to the documents and information to be provided to ECA by each Shipper pursuant to Section 2 of these General Terms and Conditions.

1.70 **"Shipper's Vessel"** shall refer to a vessel(s) identified and approved in accordance with the Service Agreement which is under the control of Shipper or persons designated by Shipper and is used to transport LNG to or from the System.

1.71 **"Specific Service Terms**" shall refer to, as applicable, Exhibits 1 (Specific FBSS Terms), Exhibit 2 (Specific IBSS Terms) and Exhibit 3 (Specific Loading Terms) of these General Terms and Conditions. Said terms contain a description of the availability, applicability and type of service, as well as the particulars that define the specific services offered by ECA in accordance with these General Terms and Conditions and the Applicable Legal Provisions.

1.72 **"Standard Calorific Value"** or "**Standard CV**" shall refer to a gross calorific value equal to 0.03726 GJ/Standard Cubic Meter.

1.73 “**Standard Cubic Meter**” shall refer to the mass in kilograms or the energy that a volume of one cubic meter of natural gas has in Gigajoules in standard conditions; i.e., at a pressure of 101.325 kPa and a temperature of 288.71 K.

1.74 “**Storage**” shall refer to the reception, holding on deposit, regasification or loading LNG and/or delivering Gas when the LNG is held on deposit in fixed installations other than pipelines.

1.75 “**Storage Service”** shall mean the services provided by ECA to the Shippers in the System, including the receipt of LNG at a Receipt Point, the storage and regasification of LNG and the delivery of an equivalent quantity of Natural Gas (less the System Operation Gas) at the Send-Out Point, either on a firm or interruptible base. “Storage Service” shall also include the loading of LNG at the Reception Point where the Shipper has agreed to maintain a Minimum LNG Inventory.

1.76 **"System"** shall mean the Marine Installations and the LNG transfer arms, tanks, vaporizers, pipelines, compressors, regulators, meters and other equipment used in the provision of the Storage Services. Except for the Marine Installations, the System shall not extend upstream of the Receipt Point or downstream of the Send-Out Point.

1.77 **“System Operation Gas”** is the quantity of gas necessary to operate the System, in accordance with the provisions of Clause 16 of these General Terms and Conditions.

1.78 “**Terminal**” shall refer to ECA’s System.

1.79 “**Terminal Limitations Determination**” shall refer to a determination made by ECA, in accordance with these General Terms and Conditions that

(i) the Shipper(s) do not have sufficient rights to use the Terminal under these General Terms and Conditions to schedule a proposed pattern of Delivery Windows and/or send-out of regasified LNG.

(ii) a proposed unloading pattern of the LNG cargoes and send-out of regasified LNG would be outside the operating capacities of the Terminal or would conflict with scheduled maintenance permitted at the Terminal; or

(iii) a proposed loading pattern of LNG would be outside the operating capacities of the Terminal or would conflict with scheduled maintenance permitted at the Terminal.

1.80 **“Unforeseen Circumstance or Event of Force”** shall have the definition provided in Clause 15 of these General Terms and Conditions.

1.81 **“Unscheduled Delivery Window”** means a Delivery Window that is not a Confirmed Delivery Window for any Shipper.

1.82 “**Uniform Hourly Rate**” refers to a 1/24 dispatch rate of the Order for a specific Gas Day.

1.83 **“US“** or “**United States**” shall refer to the United States of America.

1.84 **“United States Pacific Time”** or **“PT”** shall refer to U.S. Pacific Standard Time, as adjusted for daylight saving.

1.85 **"US Dollar**” or “**USD**” shall refer to the legal tender of the United States of America.

1.86 “**Year**” shall mean a calendar year of twelve (12) consecutive months, commencing on the First Day of January and ending on the 31st day of December in the same year.

2. ACCESS TO THE SERVICES, TYPES OF SERVICE, QUALIFYING FOR SERVICE AND CREDIT-WORTHINESS

2.1 Access to the Services.

In accordance with the Applicable Legal Provisions and the conditions to ensure open access, the procedures followed to hold Open Seasons and the contents of the Electronic Bulletin mentioned in these General Services Terms and Conditions, ECA will allow Shippers open and not unjustifiably discriminatory access to the Storage Service in its System, for which the following shall be taken into consideration:

(A) Open and not unjustifiably discriminatory access shall be limited to the Available Capacity;

(B) The Available Capacity referred to in the previous paragraph shall be understood as the capacity not yet contracted by FBSS Shippers.

(C) The provision of new services and the signing of new Service Agreements, both firm and interruptible base, shall not interfere with or affect ECA's capacity to meet its commitments under already existing Service Agreements.

(D) Shippers may only exercise the right to open access by entering into the respective Service Agreements.

(E) Open access shall be subject to Shippers’ performance of the requirements established in Section 2 of these General Terms and Conditions.

2.1.1 Availability of Service

Shippers shall receive the Storage Service in accordance with these General Terms and Conditions, provided they:

(A) Enter into a Service Agreement with ECA,

(B) Have the installations necessary available and interconnected with ECA’s installations at the Send-Out Points specified in the Service Agreement.

(C) Have provided the Financial Guarantees required by ECA, in accordance with the terms of Section 2 of these General Terms and Conditions, and

(D) Have agreed to maintain the Minimum LNG Inventory with regard to the Loading Services.

2.1.2 Denial of Service

ECA shall be entitled to deny the provision of the Storage Service to Shippers when:

(A) They do not have the capacity to deliver LNG or receive Gas;

(B) They have not submitted adequate Financial Guarantees in terms of the provisions contained in Section 2 of these General Terms and Conditions; or

(C) The Storage Service requested cannot be rendered due to technical or safety reasons.

2.1.3 Enforceability of Obligations

The Shipper’s obligations, including the obligation to pay ECA the tariff applicable to the contracted capacity, shall be enforceable from the date established in the Service Agreement. Subject to the provisions of the Unforeseen Circumstances or Force Majeure section, the Shipper’s payment obligation shall remain in force and payment must be made regardless of whether or not the Shipper has delivered LNG for Storage or if the Shipper has the installations necessary to receive the Natural Gas.

2.2 Types of Service

The Storage Service shall be provided according to the Service Agreement signed by the parties in accordance with the forms contained in these General Terms and Conditions. The parties may agree to modify these forms or the Specific Service Terms, subject to Section 17.6 of these General Terms and Conditions.

The Shipper accepts and acknowledges that while the Storage Service is being rendered, conditions may arise that require ECA to remove all or part of the Shipper's LNG from the System in accordance with these General Terms and Conditions.

2.2.1 Firm Base Storage Service (FBSS)

Once ECA has accepted the respective request, the FBSS shall be available to any party that requests said service in the System in conformance with these General Terms and Conditions. The foregoing shall be subject to there being sufficient Available Capacity at such time to meet the request and the signing of a Service Agreement in the manner provided for in these General Terms and Conditions.

The FBSS consists of storing LNG received at the Reception Point up to the Shipper's Maximum Storage Quantity (MSQ) indicated in the Service Agreement. The FBSS shall not be subject to reductions or interruptions unless stipulated otherwise in these General Terms and Conditions and the Service Agreement.

ECA may receive LNG at the Reception Point at any time in accordance with the Service Agreement and subject to an Order issued by the Shipper and party's MSQ. ECA may also deliver Gas to the Send-Out Point at any time, subject to an Order the MDQ and the ASQ.

The ASQ may be increased up to the MSQ in the quantity of LNG that the Shipper delivers for Storage by transfer of LNG in storage. The ASQ may also be reduced by the quantities delivered to the Shipper's Send-Out Point, as well as the transfer of LNG in storage and the System Operation Gas.

ECA may enter into FBSS Agreements with Shippers that meet the requirements for the rendering of the service as established in Section 2 of these General Terms and Conditions, provided that there is Available Capacity in the System.

The Regulated Tariff for the FBSS, approved by the CRE, is established in the Regulated Tariff Sheet, provided in these General Terms and Conditions.

Once the Service Agreement is signed, Shippers shall inform ECA about any quantities they need to deliver, store and/or receive in the System in accordance with the Ordering procedures established in Sections 3 and 4 of these General Terms and Conditions.

2.2.2 Interruptible Base Storage Service (IBSS).

Shippers shall be entitled to request IBSS during the terms and subject to the terms of their respective Service Agreements. However, the IBSS shall be subject to any remaining Available Capacity, after the FBSS Orders have been fulfilled.

ECA is authorized to restrict, reduce or interrupt the rendering of the IBSS when it determines that any deliveries made under same will interfere or restrict ECA's capacity to render the FBSS.

There is a significant likelihood of interruption in the rendering of the IBSS by ECA. Interruptions may occur for a variety of foreseeable and unforeseeable reasons. IBSS Shippers that schedule their Vessels under the IBSS mode shall have no assurance that ECA will be able to receive their Vessels on arrival. ECA may also require the interruptible LNG held in storage to be withdrawn in quantities and time periods that result in an increase or decrease in the withdrawal rates of said LNG in comparison with the originally scheduled withdrawal rate.

Circumstances which may cause the interruption in whole or part of ECA's capacity to receive LNG or deliver Gas at the Send-Out Point under IBSS may include, but are not limited to, changes in the scheduled arrivals or late arrivals or departures of Shipper's FBSS Vessels, each case being subject to these General Terms and Conditions and the Service Agreement. Interruptions in the reception of LNG under the IBSS may occur either prior to the arrival of or during the unloading or loading of a Shipper’s Vessel. Similarly, the interruption of the delivery of Gas under IBSS may occur either prior to the commencement of or during such delivery. ECA does not accept liability for said interruptions and the Shipper shall indemnify ECA, as well as its employees, consultants and agents for any liability in said events.

Under no circumstances shall ECA allow the activities of IBSS Shippers or the provision of the IBSS to interfere with the operations or commercial decisions of FBSS Shippers or the rendering of the FBSS service, unless otherwise stipulated in Sections 3.3(A) and 4.4 of these General Terms and Conditions.

ECA may decline to render the all or part of the IBSS (i) if any Shipper that requests the service cannot demonstrate to have the capacity to withdraw their MDQ according to their Order, (ii) if the IBSS in question may interfere with ECA's obligation to render the FBSS and (iii) if ECA issues an OFO.

ECA shall enter into IBSS Agreements with Shippers that meet the requirements to receive the Storage Service established in Section 2 of these General Terms and Conditions provided that there is capacity in the System after ECA meets its FBSS commitments and prior IBSS commitments.

The Regulated IBSS Tariff, approved by the CRE, is established in the Regulated Tariff Sheet included in these General Terms and Conditions.

Once the Service Agreement is signed, Shippers shall inform ECA about any quantities they need to deliver, store and/or receive in the System in accordance with the Ordering procedures established in Sections 3 and 4 of these General Terms and Conditions.

2.2.3 Minimum LNG Inventory and Loading Service

Within thirty (30) days after the CRE approves the revised General Term and Conditions and no later than December 1 prior to each Scheduling Year, during such Scheduling Year, ECA shall notify all Shippers with the FBSS if it requires Shippers to maintain a Minimum LNG Inventory. At their sole discretion, Shippers may decide if they intend to maintain a

Minimum LNG Inventory. Shippers that agree to maintain the Minimum LNG Inventory shall notify ECA of such decision no later than ten (10) business days after receiving the notification from ECA.

ECA shall allocate the Minimum LNG Inventory pro-rata based on the MSQs of the Shippers that agree to maintain the Minimum LNG Inventory using the following formula.

Minimum LNG Inventory = $20{,}000 m^3 \times A/B$.

where A = Shipper's MSQ, and
B = aggregate MSQ of all Shippers that agree to maintain the Minimum LNG Inventory.

In exchange for agreeing to a Minimum LNG Inventory, the Shippers in question shall be entitled to receive the Loading Services. Within five (5) business days after the Shippers notify ECA of their intention to maintain a Minimum LNG Inventory, ECA and said Shippers shall enter into Loading Service Agreements using the form attached to these General Terms and Conditions

The Loading Services terms and conditions are provided in Exhibit 3 to these General Terms and Conditions.

2.2.4 Other Services

ECA may, from time to time, provide other services, such as nitrogen injection. Engaging said services shall not be conditioned to the use of Storage Services. Any other services to be rendered shall be documented in an agreement separate and independent from the Service Agreement. The breach of any obligations under said agreement shall constitute a breach of the Service Agreement. Said other services shall be billed separately and shall not be included in the invoices issued pursuant to the Service Agreement.

2.3 Qualifying for the Storage Service

2.3.1 Shippers that request the Firm or interruptible Base Storage Service from

ECA shall complete the Service Application Form (Service Application) attached to these General Terms and Conditions in full. Shippers shall complete and return the Service Application to ECA to the e-mail address provided in the Information System:

www.energiacostaazul.com.mx

The Shipper shall submit the Service Application and ECA will determine if the service required is available. ECA will not be obligated to render the provide the Firm Base Storage Service if there is no Available Capacity. ECA shall not render the Storage Service until the Shipper in question enters into a Service Agreement. Shippers also shall be required to meet all other provisions of these General Terms and Conditions, including the credit requirements provided in Section 2. Service Agreements for each service offered by ECA shall be substantially as provided in the Service Application Forms

Shippers shall not be entitled to receive the Storage Service under these General Terms and Conditions if in arrears with their payments to ECA for any charge, tariff or fee for the Storage Service. However, with ECA’s prior consent, Shippers shall be entitled to receive or continue to receive the Storage Services if they provide a credit guarantee to ECA's satisfaction to cover payments owed to ECA.

In order to ensure non-discriminatory treatment for all potential Shippers who wish to enter into FBSS Agreements with ECA, ECA shall keep a List of Service Applications on file for one year in accordance with these General Terms and Conditions.

After receiving Service Applications that meet the requirements of these General Terms and Conditions, ECA shall determine whether or not there is Available Capacity in the System and, if so, determine whether it is sufficient to meet its commitments acquired at that time through FBSS Agreements. ECA shall evaluate each Service Application in accordance with the contractual terms and capacity requested and shall allocate the Available Capacity among the Service Applications as provided for in Section 10 of these General Terms and Conditions.

Within the thirty (30) business days from receiving the Service Application, ECA shall inform the Shipper if it can supply the service requested with the system capacity available.

If ECA has the capacity to render the service requested, it will notify the Shipper of the Financial Guarantees required according to Section 2 of these General Terms and Conditions and send the Shipper the Service Agreement for signing.

Within a period of thirty (30) business days following the receipt of the Service Agreement, the Shipper shall:

(A) provide the Financial Guarantees established in Section 2 of these General Terms and Conditions, and

(B) sign the Service Agreement and return it to ECA for signing, together with the applicable Financial Guarantees. In the case of FBSS, the Financial Guarantees shall be those set forth and described in Section 2.4.1 of these General Terms and Conditions; whereas for the IBSS, they shall be those set forth and described in Section 2.4.2 of these General Terms and Conditions.

ECA shall review the Shippers' Financial Guarantees within thirty (30) business days from receiving them. ECA shall sign the Service Agreement if they are acceptable in accordance with the requirements established in this Section. No service shall be rendered without a Service Agreement first being signed.

If the Shipper fails to return the signed Service Agreement or satisfactory Financial Guarantees within thirty (30) business days, it shall be deemed to have rejected the Service Agreement. In the event that the Shipper rejects or is deemed to have rejected the Service Agreement, the respective accepted Service Application shall be removed from the Contractual Year's List of Service Applications.

Without prejudice to the provisions of this Section, ECA shall not be required to contract capacity at tariffs below the Regulated Tariff and/or for terms of less than seven (7) Contractual Years.

the System and deliver it, as well as any third-party claims for damages caused while the product is in ECA's system until delivery.

2.11 Strict Liability

In accordance with the Applicable Legal Provisions, the Shipper shall be liable for claims that cause losses and damages. The liability shall be limited to the payment of any immediate and direct consequential damages of the accident

2.12 Extra-contractual Personal Liability

In accordance with the Applicable Legal Provisions, the parties shall be liable for direct and immediate losses and damages caused by operating illegally or for damage caused to the other.

3. ORDERS AND SCHEDULING OF NATURAL GAS

The Storage Service shall be rendered only after the Shipper has entered into a Service Agreement and has provided ECA with an Order for such service in accordance with this Section 3.

3.1 General Rules

(A) The Orders for Gas to be delivered at the Send-Out Point shall meet the requirements of Section 3.1(C) below, on the understanding that ECA may accept Orders delivered by other means provided that (i) the operating conditions permit them, (ii) other Shippers are not adversely affected, and (iii) the terms and conditions for such delivery have been confirmed as established.

(B) On submitting an Order, the Shipper declares and guarantees to have obtained all the authorizations necessary to receive Gas from the System at the Send-Out Point and that all the contractual agreements necessary are for the pipeline transportation of Natural Gas from the System are current. ECA may depend completely on the information provide with the Order to confirm said Order and schedule the service.

(C) Order Entry Methods

(1) Orders may be submitted through the Information System or other mutually agreeable means.

(2) The Shipper must specify in the Service Agreement the person appointed to provide ECA with the Order information set forth in this Section. The Shipper may advise the change of said appointment in writing at any time. If the Shipper appoints another person to provide this information, ECA shall be entitled to rely fully on the Orders provided previously by the Shipper's representative.

(D) ECA shall be entitled to decline to deliver any Natural Gas not ordered promptly or correctly. ECA shall not be liable to the Shipper or any other party as a direct or indirect consequence of such refusal and the Shipper agrees to indemnify, defend and hold ECA, its respective employees, consultants and agents, harmless from any proceeding, judgment, fine, loss or damage, cost and expense (including sufficient legal fees), derived from or related to such refusal, except to the extent that said proceeding, judgment, fine, loss or damage, cost and expense results from ECA's negligence, bad faith or willful misconduct.

(E) The Shipper shall comply with the requests for reasonable additional information deemed necessary by ECA to render the service described herein or to comply with the reporting or other requirements of the Commission, the port authorities or other authorities with due jurisdiction.

(F) The Shipper shall inform ECA immediately of any changes in quantities requested for withdrawal, regardless of whether or not such notifications are within the times specified herein.

(G) The Shipper shall take the actions necessary in order that the operator of each downstream pipeline of the Send-Out Point or other Send-Out Points assigned in any Order or Order Change confirm said Order or Order Change in writing or through another mutually acceptable system prior to implementation by ECA.

(H) ECA is not obliged to the accept any Order for the withdrawal of Natural Gas if Shipper does not have sufficient Available Stored Quantity to accommodate such request.

3.2 Natural Gas Withdrawal Orders

(A) Content of Order

Natural Gas Withdrawal Orders shall be placed in accordance with the information required by ECA in the terms of this Section 3 in order to coordinate the service with downstream gas pipelines.

The Shipper may place its Orders for any period of Gas Days, provided that the start and end dates of the Orders are within the term of the Shipper's Service Agreement. Said Orders shall be considered as Standing Orders. All types of Orders shall be clearly and separately identified to be able to distinguish service priorities.

(B) Monthly Service

Natural Gas Withdrawal Orders scheduled for the Gas Month shall be submitted by the fifteenth (15th) day of the preceding Month. Natural Gas Withdrawal Orders shall be placed using the form provided by ECA and shall be consistent with the Order deadlines of pipelines interconnected downstream.

(C) Next-Day Service (Prompt Order Cycle and Evening Order Cycle).

The Shipper shall be entitled place Natural Gas Withdrawal Orders in writing for any Gas Day in accordance with the guidelines provided by ECA. Excess Quantities shall be requested in separate Orders. Next-Day Orders shall replace Standing Orders only for the next Gas Day.

(D) Same-Day Orders

The Shipper may place a Same-Day Natural Gas Withdrawal Order pursuant to the ECA guidelines. A Same-Day Order shall specify the effective date, time and daily quantity. The downstream pipelines or other Send-Out Points shall agree the hourly flows for said Gas Day.

Same-Day Orders may be used to request increases or decreases in total scheduled quantities. Same-Day Orders other than those placed during the Same-Day 2 Order Cycle (described below) shall have priority over IBSS volumes already ordered and scheduled. Requests to increase IBSS Orders shall be permitted only if capacity is available and other interruptible storage services are not affected. Said changes shall take effect only when permitted by the system operating conditions, as determined by ECA.

The dates of Same-Day Orders may not be modified and shall replace the Standing Orders only during the Gas Day. The volumes of Same-Day Orders shall represent the total volumes to be delivered before the end of the current Gas Day.

(E) Order Cycles

I. NEXT-DAY SERVICE

PROMPT ORDER CYCLE

11:30 a.m. PST - Shipper sends Orders;
11:45 a.m. PST - ECA receives Orders;
12:00 a.m. PST - ECA confirms reception of Orders;
2:30 p.m. PST - ECA receives confirmations from the transportation systems located after the Send-Out Point;
3:00 p.m. PST - reception by Shipper and from the downstream systems of the confirmations of the scheduled volumes.

[Change - effective April 16, 2015 due to FERC Order No. 809

TIMELY ORDER CYCLE

11:00 a.m. PST - Shipper sends Orders;
11:15 a.m. PST - ECA receives Orders;
11:30 a.m. PST - ECA confirms reception of Orders;
2:30 p.m. PST - ECA receives confirmations from the transportation systems located after the Send-Out Point;
3:00 p.m. PST - Reception by Shipper and from the downstream systems of the confirmations of the scheduled volumes.
7:00 a.m PST – ECA starts gas flow]

EVENING ORDER CYCLE:

4:00 p.m. PST - Shipper sends Orders;
4:15 p.m. PST - ECA receives Orders;
4:30 p.m. PST - ECA confirms reception of Orders;
6:00 p.m. PST - reception of confirmations filled out by ECA from the systems connected downstream;
7:00 p.m. PST - ECA provides the confirmation of the volumes scheduled to the Shippers and operators of the points affected, reports the volumes scheduled and informs the bumped parties. Advance notice to bumped parties shall be provided by telephone, fax or e-mail.

[Change - effective April 16, 2015 due to FERC Order No. 809

EVENING ORDER CYCLE:

4:00 p.m. PST - Shipper sends Orders;
4:15 p.m. PST - ECA receives Orders;
4:30 p.m. PST - ECA confirms reception of Orders;
6:30 p.m. PST - reception of confirmations filled out by ECA from the systems connected downstream;
7:00 p.m. PST - ECA provides the confirmation of the volumes scheduled to the Shippers and operators of the points affected, reports the volumes scheduled and informs the bumped parties. Advance notice to bumped parties shall be provided by telephone, fax or e-mail.

7:00 a.m PST – ECA starts gas flow]

Scheduled quantities resulting from Evening Orders shall take effect at 7:00 a.m. PST on the following Gas Day.

II. SAME-DAY SERVICE

SAME-DAY 1 ORDER CYCLE:

8:00 a.m. PST - Shipper sends Orders;
8:15 a.m. PST - ECA receives Orders;
8:30 a.m. PST - ECA confirms reception of Orders;
11:00 a.m. PST - reception of confirmations filled out by ECA from the systems connected downstream;
12:00 noon PST-ECA provides volumes scheduled to Shippers and operators of the points affected, provides quantities scheduled and notice to bumped parties. Advance notice to bumped parties shall be provided by telephone, fax or e-mail.
The quantities resulting from Same-Day 1 Orders shall take effect at 3:00 p.m. PST on the Gas Day.

[Change - effective April 16, 2015 due to FERC Order No. 809

INTRADAY 1 ORDER CYCLE:

8:00 a.m. PST - Shipper sends Orders;
8:15 a.m. PST - ECA receives Orders;
8:30 a.m. PST - ECA confirms reception of Orders;
10:30 a.m. PST - reception of confirmations filled out by ECA from the systems connected downstream;
11:00 a.m PST - ECA provides volumes scheduled to Shippers and operators of the points affected, provides quantities scheduled and notice to bumped parties. Advance notice to bumped parties shall be provided by telephone, fax or e-mail.
12:00 p.m. (noon) PST – ECA starts gas flow]

SAME-DAY 2 ORDER CYCLE:

3:00 p.m. PST - Shipper sends Orders;
3:15 p.m. PST - ECA receives Orders;
3:30 p.m. PST - ECA confirms reception of Orders;
6:00 p.m. PST - reception of confirmations filled out by ECA from the transportation systems located upstream and downstream.
7:00 p.m. PST - ECA provides the volumes scheduled to Shippers and operators of the points affected.

[Change - effective April 16, 2015 due to FERC Order No. 809

INTRADAY 2 ORDER CYCLE:

12:30 p.m. PST - Shipper sends Orders;
12:45 p.m. PST - ECA receives Orders;
1:00 p.m. PST - ECA confirms reception of Orders;
3:00 p.m. PST - reception of confirmations filled out by ECA from the transportation systems located upstream and downstream.
3:30 p.m. PST - ECA provides volumes scheduled to Shippers and operators of the points affected, provides quantities scheduled and notice to bumped parties. Advance notice to bumped parties shall be provided by telephone, fax or e-mail.
4:00 p.m. PST – ECA starts gas flow]

[Addition - effective April 16, 2015 due to FERC Order No. 809

INTRADAY 3 ORDER CYCLE:

5:00 p.m. PST - Shipper sends Orders;
5:15 p.m. PST - ECA receives Orders;
5:30 p.m. PST - ECA confirms reception of Orders;
7:30 p.m. PST - reception of confirmations filled out by ECA from the transportation systems located upstream and downstream.
8:00 p.m. PST - ECA provides the volumes scheduled to Shippers and operators of the points affected.
8:00 p.m. PST – ECA starts gas flow]

The quantities resulting from Same-Day 2 Orders [correction - Intraday 3 Orders] shall take effect at 7:00 p.m. PST [correction – 8:00 p.m. PST] on the Gas Day.

Firm Same-Day Orders placed in the Same-Day 2 Order [correction - Intraday 3 Order] Cycle may not bump ordered and scheduled IBSS volumes.

At its discretion, ECA shall have the option to accept Orders at late as permitted by its operating conditions and without detriment to other Shippers and after having obtained the confirmation that the satisfactory arrangements with the downstream transportation systems have been made. If subsequent Orders are accepted, ECA shall schedule them after the Orders received before the Order deadline.

(F) Changes in Orders:

To modify an Order, it must be replaced by a new Order. Orders placed for periods between the start and end dates of a Standing Order shall replace said Standing Order for the Gas Day(s) specified only in the new Order, but shall not replace the remainder of said Standing Order.

Said Orders shall be received by ECA in accordance with the scheduling times provided in this Section. If not information of downstream transportation system adjustments is received, ECA shall use the most recent confirmed Order.

(G) Information Reliability:

In order to schedule and allocate an Order, ECA shall may fully rely on the information submitted as part of the Order. The Shipper shall provide ECA with the name and telephone number of the contact person in non-business hours and emergencies by telephone, fax or any other mutually agreed electronic means. Said information shall be updated as often as changes are made. ECA may rely solely on the information provided by the Shipper and shall not be liable to the Shipper said contact information is outdated and communication attempts with the Shipper's contact are unsuccessful.

3.3 Natural Gas Withdrawal Scheduling Procedure in accordance with Exhibits 1 and 2 of these General Terms and Conditions.

(A) ECA shall schedule the quantities of Natural Gas requested for withdrawal by Shippers in the following order:

(1) Firm Base Storage Service pursuant to Exhibit 1 of these General Terms and Conditions (except Same-Day 2 Orders);

(2) Interruptible Base Storage Service of the type specified in Section 1.69(i) (except Same-Day 2 Orders);

(3) Same-Day 2 FBSS Orders;

(4) Same-Day 2 IBSS Orders; and

(5) Interruptible Base Storage Service of the type specified in Section 1.69(ii)

(B) Firm Base quantities requested that exceed ECA's Operational Capacity shall be scheduled on a pro-rata basis based on each Shipper's MSQ.

3.4 Pre-determined Natural Gas Withdrawal Allocations

(A) For all the Natural Gas to be withdrawn by the Shipper, said party shall take all the actions necessary so that the operator of the transportation installations located immediately downstream of ECA's Send-Out Point may provide a pre-determined methodology to be used to allocate said Natural Gas via the Send-Out Point. In the event the parties cannot agree an allocation methodology, the pro-rata method shall be used based on the Orders confirmed. The downstream operator shall provide the allocation. ECA shall accept such allocations provided they are operationally and administratively feasible.

(B) The allocation methodology shall be provided to ECA in writing before the start of the Gas Day on which Gas is to be withdrawn and shall describe the methodology for all Service Agreements in which quantities are scheduled at the Send-Out Point.

(C) If no acceptable methodology is provided, ECA shall allocate the actual quantities delivered among the Shippers based on the proportion of each scheduled quantity to the total quantities of gas scheduled at the Send-Out Point applicable to the total quantity of natural gas actually delivered by ECA.

(D) Changes to the daily allocation methodology may be made on a monthly basis and shall be submitted in writing at least five (5) days in advance of the Gas Month in which changes are made. No retroactive reallocations of any transaction shall be permitted.

(E) ECA shall not be liable to any Shipper as a result of the use of any methodology described in this Section and the Shipper agrees to indemnify, protect, and hold ECA, as well as its respective employees, consultants and agents, harmless from any proceeding, judgment, fine, loss or damage, liability, cost and/or expense (including reasonable legal fees), derived from or related to the use of said methodology, except to the extent that said proceeding, judgment, fine, loss or damage, liability, cost and/or expense is the result of ECA's negligence, bad faith or willful misconduct.

4. ORDERING AND SCHEDULING PROCEDURES TO TRANSFER LNG IN THE SYSTEM

The Storage Service shall be rendered only after the Shipper has entered into a Service Agreement and has provided or has taken all the measures necessary to provide ECA with an Order for such service in accordance with Section 4 of these General Terms and Conditions.

5. OPERATING CONDITIONS

In addition to the operating conditions set forth below, the Shipper shall comply with any detailed operating procedures issued by ECA.

5.1 General

(A) The Shipper shall make all necessary arrangements with other parties at the Reception Point where the Shipper delivers LNG to ECA for storage, at the Reception Point where ECA returns LNG to the Shipper, and at the Send-Out Point where ECA delivers Natural Gas to the Shipper. Such arrangements must be compatible with ECA's System operations.

(B) ECA reserves the right to mix the LNG received and stored with LNG from other sources and to treat and handle it freely, as if it were its own property, but without using it unless permitted to do so by these General Terms and Conditions. The Natural Gas or LNG delivered to Shipper shall be understood as not to consist of the same molecules as originally received from the Shipper

(C) If the Shipper has delivered LNG that meets the requirements of Section 11.1, and provided that said Shipper has complied with its obligation to withdraw Gas or LNG before its quality falls below a non-condition level pursuant to the provisions of Section 5.3(C), ECA shall be required to deliver Natural Gas or LNG that can be sold commercially in accordance with the provisions of Section 11.1.

5.2 Operating Conditions for the Reception of LNG from Shipper's Vessels.

(A) All Shipper's Vessel shall be compatible with the System.

(B) The Shipper’s installations shall have all the governmental authorizations, port licenses and customs clearances required and shall be responsible for paying all the associated tariffs or taxes, charges, fees or other costs.

(C) ECA shall make available or ensure the availability of berthing, unloading and loading facilities in the System, including:

(1) mooring equipment;

(2) sufficient lighting to permit docking maneuvers day or by night to the extent permitted by the port authorities;

(3) transfer arms, pipes and other appropriate facilities to enable the loading of LNG at an estimated rate of 12,000 cubic meters/hour or any other rate agreed by ECA and the Shipper; and

(4) a vapor return line from the Shipper's Vessel to shore facilities with a diameter sufficient to maintain the correct operating pressure in the tanks of the Shipper's Vessel.

(D) LNG shall be transferred in accordance with current Federal, State and Local safety and other laws, regulations and standards.

(E) Shippers shall advise ECA in writing of the estimated arrival date and time at the Arrival Buoy, as well as the estimated quantity of LNG to be transferred and the estimated transfer time. Shippers shall send ECA, either directly or via a third party, the following written designation notices:

(1) an initial notice on the departure of the Shipper's Vessel from the port of origin and shall stipulate an estimated time of arrival;

(2) a second notice 96 (ninety six) hours prior to the estimated time of arrival;

(3) a third notice 72 (seventy two) hours prior to the estimated time of arrival;

(4) a fourth notice 48 (forty eight) hours prior to the estimated time of arrival;

(5) a fifth notice 24 (twenty four) hours prior to the estimated time of arrival; and

(6) a final notice 5 (five) hours prior to the estimated time of arrival, with any changes regarding the estimated transfer time.

(F) The Shipper shall issue the Availability Notice to ECA as soon as its Vessel has received all relevant port clearances and is ready to discharge the cargo on arrival at the berth.

(G) The captain of the Shipper's Vessel shall give written notice to ECA or its representative as soon as the Vessel is berthed alongside the jetty and is ready to transfer its cargo.

5.3 LNG Storage Operating Conditions

(A) Venting

There may be occasions in which Shippers may not be able to withdraw their MinDDQs. In these cases, ECA may have to dispose of the LNG by venting. The Available Stored Quantity of affected the Shipper shall be reduced in proportion to the portion of the LNG vented applicable to the Shipper. Said portion shall be the ratio between the Shipper's MSQ and the total MSQ contracted of all the Shippers with LNG in stock at that time.

(B) Transfers of Stored LNG

(1) Subject to prior notice to ECA, the Shipper may transfer all or a portion to any other Shipper that receives the Storage Service pursuant to the Contract and Exhibit 1 of these General Terms and Conditions provided that the following conditions are met:

(a) Both the assignor and assignee of the Available Stored Quantity shall provide ECA with a written notification of the transfer; and

(b) The transfer does not cause the Available Stored Quantity to exceed the MSQ specified in the respective Service Agreement.

(2) The Shipper may transfer all or a portion of its rights to Available Stored Quantity to any Shipper that receives Storage Service pursuant to the Service Agreement and Exhibit 2 of these General Terms and Conditions, and their Available Stored Quantity rights provided that the following conditions are met:

(a) The Shipper obtains prior approval from ECA for such transfer; and

(b) All the requirements of Section 5.3 (B)(1) of these General Terms and Conditions are met.

(3) ECA shall recognize the transfer for the purposes of calculating Available Stored Quantity one (1) business day after receiving the notification required by Section 5.3(B)(1)(a).

(4) ECA will charge and the Shipper shall pay the Ownership Transfer Fee per GJ at the Standard CV as stated in the Regulated Tariff Sheet with a minimum charge of USD 1,000.00 per transfer.

(C) Non-Merchantable LNG Cycles/Quality

The Shipper shall be responsible for the withdrawal of its LNG from the System before its quality deteriorates to a level that cannot be traded in accordance with Section 11.1 of these General Terms and Conditions. If the Shipper fails to withdraw said LNG, then ECA may, at its entire discretion, withhold the LNG without any claims whatsoever by the Shipper being admissible. In this case, the Shipper shall indemnify ECA and hold it harmless from all costs, damages and liabilities that arise from the Shipper's failure to withdraw and ECA's disposal of said LNG. The aforementioned costs, damages and liabilities shall include the storage charges pursuant to the Exhibit 1 or 2 of these General Terms and Conditions in accordance with the respective Service. ECA shall distribute any net income earned from the sale of LNG, to which it takes title hereunder in accordance with Section 21 of these General Terms and Conditions.

6.2 Natural Gas Withdrawal Operating Conditions

(A) ECA shall not be required to deliver Natural Gas at a rate in excess of the Uniform Hourly Rate of the MDQ specified in Shipper's Service Agreement.

(B) The Shipper shall place its Order every day for each Gas Day for delivery at the Send-Out Point in an amount no less than the MinDDQ for said Gas Day.

5.5 Terms of Service

(A) Each Shipper shall have contractual rights afforded to it by the following service characteristics:

(1) A maximum volume for the purposes of unloading the Shipper's Vessel (MSQ less Shipper's Available Stored Quantity)

(2) Maximum monthly throughput

(3) Maximum Daily Delivery Quantity (MaxDDQ)

(4) Minimum Daily Delivery Quantity (MinDDQ)

(5) Maximum Storage Quantity (MSQ)

(B) If the Shipper exceeds its MSQ at any time, then in addition to any Excess Charge payable by the Shipper, said party shall be required to withdraw the Quantities of Natural Gas necessary pursuant to its MaxDDQ until the ASQ matches the MSQ.

(C) The Shipper shall be required to withdraw Quantities of Natural Gas pursuant to its MinDDQ until such time as its Available Stored

Quantity is reduced to zero (0). Under no circumstances shall be Shipper be entitled to withdraw quantities of Natural Gas above its ASQ.

(D) The Shipper’s ASQ may exceed its MSQ levels subject to prior agreement by ECA.

(E) In the event that the Shipper fails to meet the contractual service parameters described in this Section 5.5, said party shall be subject to the remedies established in Section 8 of these General Terms and Conditions.

6. SUSPENSION, REDUCTION OR MODIFICATION OF THE STORAGE SERVICE

6.1 No liability for ECA

Under no circumstances shall ECA be held legally responsible for the suspension of the service for the following reasons:

(A) Unforeseen Circumstance or Event of Force Majeure.

(B) Failures in Shipper’s facilities or faulty operation of its facilities;

(C) Works necessary for the maintenance, expansion or modification of the System, after notice to the Shippers, when said modifications are required as a result of a Change in the Law;

(D) Shipper’s failure to fulfill their contractual obligations with respect to their Service Agreement and/or to these General Terms and Conditions.

(E) An OFO issued by ECA (unless due to unscheduled System maintenance or repairs), and

(F) Planned maintenance in accordance with Section 4.1 (P).

Except as set forth in Section 15.2, no suspension of Service pursuant to this Section 6.1 shall relieve Shipper of its obligations to pay the applicable Storage Service charges.

10.2 Applicants may submit written Service Applications for Available Capacity at any time.

10.3 If multiple Service Applications are received at the same time, ECA shall evaluate them and grant the Available Capacity to the application with the greatest economic value as determined by ECA. If the different Service Applications have the same economic values, the service shall be offered successively beginning with the earliest application. If the different Service Applications have the same economic values, the service shall be assigned at random.

10.4 If ECA accepts a Service Application, the applicant shall complete and return the Service Agreement in accordance with Section 2 of these General Terms and Conditions.

10.5 Notwithstanding the foregoing, ECA shall not be required to offer or enter into a Service Agreement at a tariff below the Regulated Tariff. ECA may, at its sole discretion, offer or enter into a Service Agreement at a tariff below the Regulated Tariff for the service requested. Before ECA is obliged to offer or enter into a Service Agreement, ECA and the applicant shall agree a tariff below the Regulated Tariff for any application. Any Conventional Tariff agreed shall apply for the entire term of the Service Agreement.

11. QUALITY

11.1 The LNG received for the Storage Service shall be of a quality that once stored and subsequent regasification to Natural Gas, it shall meet the quality level required for commercial sale, which shall require cumulative compliance with the following:

(i) the terms of Official Mexican Standard NOM-001-SECRE-2010 (which replaces and supersedes NOM-001 SECRE-2003) and with any other Official Mexican Standard that in the future modifies or substitutes it in whole or in part, and

(ii) the applicable quality standards of the interconnecting United States' pipeines to which Shippers may have access.

ECA shall not be obliged to receive LNG that does not meet both of these standards.

11.2 The Shipper agrees to indemnify, defend and hold ECA, its respective employees, consultants and agents, harmless from any proceeding, judgment, fine, loss or damage, cost and expense (including reasonable legal fees) that arise from or are related to Shipper's breach of the provisions of this Section 11, except if said proceeding, judgment, fine, loss or damage, cost and expense is the result of negligence, bad faith or willful misconduct by ECA or is the result of ECA's decision to receive LNG from the Shipper in the knowledge that said LNG does not meet the quality requirements.

If the LNG received by ECA from the Shipper does not meet the provisions established in this Section 11, ECA shall the Shipper of the breach and may decline to accept the delivery until the Shipper corrects the deficiency.

11.3 The Terminal shall be equipped with nitrogen injection systems to adjust the quality of the natural gas in order to ensure that the rated natural gas send-out rate meets the requirements of Official Mexican Standard NOM-001-SECRE-2010 “Quality of Natural Gas”, considering the different types of LNG that will be received at the Terminal.

12. METERING

12.1 Metering the Quantity of LNG Received from Shipper's Vessel

Metering the volume of LNG transferred. In international trade, the volume of LNG transferred is metered in the vessel's tanks to ensure greater metering accuracy.

- Vessels shall hold a valid calibration certificate for each LNG tank issued by a qualified certification services company recognized internationally by the LNG industry. Said calibration certificate includes the specific tables to determine the volumes of LNG and vapor present in the tank when metering the LNG level.

The advanced termination shall not release the parties from their prior obligations pending performance at the advanced termination date.

15.3 The party that claims an Unforeseen Circumstance or Event of Force Majeure, whether ECA or the Shipper, shall inform other as soon as possible to explain the details of the occurrence and shall remedy the obstacle to perform with all reasonable diligence. This condition is on the understanding that said requirements or remedies shall not require the settlement of strikes or lockouts by accepting the claims filed against ECA or the Shipper when such conciliation is unsuitable for either party.

16. System Operation Gas

In addition to the venting necessary due to the circumstances described in Section 5.3(A), ECA shall require a certain quantity of System Operation Gas and provision of the Storage Service ("**System Operation Gas**") including, but not limited to (a) System Operation Gas; and (b) quantities of Gas lost and unaccounted for during the maintenance, repair and the calibration of the metering equipment and the meter tolerances (to avoid any doubts, System Operation Gas does not include any regasified LNG returned to the Shipper's Vessel during the transfer of LNG). Therefore, ECA shall be entitled to withhold and use, at no cost or charge from Shipper's Available Stored Quantity, a quantity of gas equal to the result of multiplying said Shipper's Available Stored Quantity by the percentage of gas required to operate the System.

The "**Percentage of Gas Required to Operate the System**" is set forth in the Regulated Tariff Sheet, which ECA shall review every year to reflect the actual amount of gas required to operate the System, as modified or increased from time to time.

17. MISCELLANEOUS PROVISIONS

17.1 Applicable Legal Provisions; Applicable Law

These General Terms and Conditions are issued pursuant to the Applicable Legal Provisions. These General Terms and Conditions are congruent with the aforementioned legal codes, the terms and conditions

REGULATED TARIFF SHEET

ENERGIA COSTA AZUL, S. DE R.L. DE C.V.
LIQUIFIED NATURAL GAS RECEPTION, STORAGE AND REGASIFICATION TERMINAL
PRICE LIST

Published in accordance with the provisions of the Energy Regulation Commission's (CRE) Tariffs Directive.

Service:	**Units**	**Tariff or Charge**
Firm Base (FB)	Pesos/Gjoule/Day	$0.9100
Interruptible Base (IB)	Pesos/Gjoule/Day	$0.9091
Excess Storage Charge (ESC)	Pesos/Gjoule/Day	$0.4095
Excess Storage Withdrawal Charge (ESWC)	Pesos/Gjoule	$3.4502
Interruptible Send-out	Pesos/Gjoule	$3.4467
Gas Reimbursement	On Gas withdrawn	1.25%
Title Transfer	Pesos/Gjoule	$0.1240

Exhibit 1

FIRM BASE STORAGE SERVICE

1. AVAILABILITY

These Specific FBSS Terms are available to any qualified party (hereinafter referred to as the “Shipper”) that requests the Firm Base Storage Service from ECA pursuant to Section 2 of the General Terms and Conditions and once the ECA has reviews and approved the application, has entered into a Firm Base Service Agreement under these Specific FBSS Terms and subject to the Tariffs listed in the Regulated Tariff Sheet. Said Service Agreement shall generally be signed in the terms of the form attached to these General Terms and Conditions, of which these Specific FBSS Terms form part.

If necessary, the Shipper shall coordinate the transportation services with third parties or separately for the Storage Service specified herein.

2. APPLICATION AND TYPE OF SERVICE

2.1 These Specific FBSS Terms shall apply to the Firm Base Storage Service rendered by ECA in accordance with the General Terms and Conditions and the terms of the Service Agreement.

2.2 ECA shall not be obliged to render any Storage Service for which there is no Available Capacity.

2.3 ECA shall reserve the right to render the Storage Service and the withdrawal capacity from storage proportionally and constantly to all Shippers in order to ensure the optimal use of the combined storage and withdrawal capability of the installations on an open access and non-discriminatory basis.

3. TARIFFS

The tariffs and charges for the Firm Base Service in accordance with the Specific FBSS Terms shall be as follows:

3.1 Storage Capacity Charge

The Storage Capacity Charge shall be the result of multiplying the Firm Base Storage Service Tariff stated in the current Regulated Tariff Sheet by the number of Gas Days in the Gas Month for which Storage Service is reserved, and by the Shipper's reserved Maximum Storage Quantity stipulated in the Service Agreement.

The Storage Capacity Charge for billing period m during the Contractual Year shall be calculated as follows:

$$\boxed{SCC_m = FBSST \quad * \quad D_m \quad * \quad MSQ}$$

where:

SCC_m = The Storage Capacity Charge for billing period m (in US$).

FBSST = The Firm Based Storage Service Tariff (in US$/GJ/Gas Day) for billing period m as set forth in the Regulated Tariff Sheet

D_m = Number of Gas Days in billing period m during the Gas Month in which the Storage Service is reserved.

MSQ = Maximum Storage Quantity (GJ) at the Standard CV.

3.1.1 Tariff Adjustments

The Firm Base Storage Service Tariff will be adjusted in accordance with the Prices and Tariffs Directive.

3.2 Additional Charges

The Storage Capacity Charge shall be payable in addition to any other applicable charges, as well as any other charges specified in the General Terms and Conditions, in the Regulated Tariffs Sheets, and any additional charges applicable to the service described in these Specific FBSS Terms, including but not limited to any charges imposed by any Governmental Authority and due to changes in the law that require additional capital investment in the System or changes in the operation of the System, that result in increases in the Firm Base Storage Service Tariff.

3.3 Excess Charge

An Excess Charge shall be applied each Gas Day on which the quantity of LNG stored exceeds a Shipper’s MSQ (excess storage) or when the quantity of Natural Gas withdrawn by a Shipper exceeds the Shipper’s MDQ, as increased pursuant to any IBSS of the type set forth in Section 1.67(ii) obtained by the Shipper (excess storage withdrawal). If a Shipper’s ASQ exceeds its MSQ in relation to the storage of a cargo delivered for re-loading or to maintain the Shipper’s Minimum LNG Inventory, the Shipper shall not be charged the Excess Charges for such surplus. The Excess Charge shall be determined by the sum of the excess storage quantities and the excess withdrawal quantities for each Gas Day of the Gas Month in which an excess is registered.

Subject to the adjustments specified in the following formula, the daily quantity of the excess storage will be the result of the actual quantity of LNG stored in excess of the User's MSQ and the Firm Base Storage Service Tariff stipulated in the Regulated Tariffs Sheet. Subject to the adjustments specified in the following formula, the daily quantity of the excess withdrawal from Storage will be the result of the actual quantity of Natural Gas withdrawn on each Gas Day in excess of the User's MDQ and the Firm Base Storage Service Tariff stipulated in the Regulated Tariffs Sheet.

The formula used to calculate the Excess Charge is as follows:

$$\boxed{ESC_m = \sum ESC_d}$$

And

$$\boxed{ESWC_m = \sum_d (ESC_d)}$$

Where,

$$\boxed{ESC_d = FBSST * ECAF * (LNGS_d - MSQ)}$$

$$\boxed{ESWC_d = FBSST * (1 - ECAF) * SFSW * (NGW_D - MaxDDQ)}$$

When,

$$\boxed{NGW_d > MaxDDQ}$$

$$\boxed{ASQ_d > MSQ}$$

Where,

ESC_m = The Excess Storage Charge for billing period m (in USD).

ESC_d = The Excess Storage Charge of Gas Day d. (is USD).

$ESWC_m$ = The Excess Storage Withdrawal Charge of billing period m. (in USD).

$ESWC_d$ = The Excess Storage Withdrawal Charge of Gas Day d . (In USD).

FBSST = The Firm Base Storage Service Tariff (in US$/GJ) for billing period m as set forth in the Regulated Tariff Sheet

ASQ_d = Available Stored Quantity on the Gas Day d (metered in GJ to the Standard CV).

NGW_d = Natural Gas withdrawn from Storage on the Gas Day d (metered in GJ to the Standard CV).

MaxDDQ = Maximum Daily Delivery Quantity

MSQ = Maximum Storage Quantity

ECAF = Excess Cost Allocation Factor (Storage to Total) as per the Regulated Tariff Sheet.

SFSW = Storage to Storage Withdrawal Ratio as per the Regulated Tariff Sheet.

d = Gas Days in billingperiod m.

3.4 Penalty Charge

In the event that the Shipper uses the Storage Service for a period longer than the term of the Service Agreement, at the discretion of ECA, said Shipper shall forfeit the ownership of the quantity of LNG applicable to said period or pay ECA a penalty on said quantity. The monthly penalty shall be three (3) times the tariff stipulated in the Service Agreement signed by and between ECA and the Shipper.

3.5 Tariff Ranges

Unless the parties agree the application of a Conventional Tariff, all Service tariffs applicable to the Shipper pursuant to this document shall be the Regulated Tariff set forth in the Regulated Tariff Sheet, plus all applicable surcharges and any other charges specified in these Specific FBSS Terms, the Service Agreement or in the General Terms and Conditions. ECA shall not be required to enter into any Storage Service Agreement at tariffs below the Regulated Tariff per GJ.

3.6 System Operation Gas

The Shipper shall reimburse ECA in kind for the use of fuel and for gas lost and not accounted for. If ECA accepts this, the Shipper may use gas provided from other heat sources at a thermally-equivalent base. The monthly System Operation Gas shall be determined in accordance with the General Terms and Conditions.

3.7 Balancing and Other Charges

If balancing or other charges are incurred in accordance with the General Terms and Conditions, then such charges shall also be applicable.

3.8 Fees, Taxes, Levies and Other Charges

Shipper shall pay, and/or reimburse ECA for, as applicable, such fees, taxes, levies and other charges imposed on Shipper's Vessels or the LNG Shipper delivers to the System, as provided in Sections 13 and 14 of the General Terms and Conditions.

3.9 Conventional Rates

Shipper and ECA may agree to a Conventional Rate with respect to the charges identified in this this Section 3. Such Conventional Rate shall be set forth on Exhibit B of the respective Service Agreement. The Regulated Rate shall be available to any Shipper that does not opt for a Conventional Rate. In accordance with regulations set forth by the

Directive of Prices and Rates, and subject to the approval of the CRE, the Regulated Rates payable to ECA may be modified and the Shipper shall remain obligated to pay said adjusted rates, in accordance with the Applicable Legal Provisions. Said changes shall not intend to affect or will affect Service Agreements with Conventional Rates already in force with Shippers.

4. TERMS AND CONDITIONS

The General Terms and Conditions are hereby incorporated by reference in these Specific FBSS Terms.

In the event of conflicts between the General Terms and Conditions and the provisions of these Specific FBSS Terms, the provisions of the General Terms and Conditions shall prevail. In the event of conflicts between the General Terms and Conditions and the Applicable Legal Provisions, the later shall prevail.

5. RESERVE

Pursuant to the Applicable Legal Provisions and subject to prior approval of the CRE, ECA may make changes to the tariffs, charges and other terms of the Regulated Tariff Sheet, to these Specific FBSS Terms and to the other provisions of the General Terms and Conditions, as well as to their application, including the Service Agreement Form. The Regulated Tariff Sheet, these Specific FBSS Terms and the General Terms and Conditions, with their respective modifications, shall apply to all Service Agreements valid from the date the Commission approves the respective modification.

FIRM BASE STORAGE SERVICE
SERVICE AGREEMENT FORMS

CONTRACT NO. ___________

THIS AGREEMENT is signed and takes effect on the _______________ day of, ____________, ________________ by and between:

ENERGÍA COSTA AZUL, S. DE R.L. DE C.V., (hereinafter referred to as "ECA"), a limited liability variable capital company and

____, a ________ company (hereinafter referred to as the “Shipper"), domiciled at _______________________ and with Federal Taxpayer Registration Number ____________________.

In accordance with the covenants and agreements as stipulated herein by both parties, ECA and the Shipper agree the following:

ARTICLE 1 - SERVICE

ECA accepts to receive and store in its System up to the Maximum Storage Quantity contracted on the discharge of the Shipper's Vessels as stipulated as follows. The volume of LNG stored will be withdrawn, regasified and delivered to the Shipper in accordance with the terms and conditions of its Firm Base Service Agreement, as stipulated as follows.

Maximum Storage Quantity: _________ GJ at Standard CV

Maximum Daily Delivery Quantity: _______________________ GJ/Gas Day

Minimum Daily Quantity:

(i) on Gas Days when the LNG Boil-Off is affected by a Shipper’s Vessel delivering LNG to the System: __________GJ/Gas Day

(ii) on Gas Days when the LNG Boil-Off is not affected by a Shipper’s Vessel delivering LNG to the System: ______GJ/Gas Day

Exhibit A to this Agreement stipulates how LNG may be received and delivered. Exhibit A may be amended by written agreement between ECA and the Shipper and shall be inserted into this Agreement to form an integral part hereof.

ARTICLE 2 - TERM

This Agreement shall take effect beginning the date stated above. ECA shall provide the Firm Base Service to the Shipper pursuant to this Agreement from ____________________________________ until _______________________, the date on which this Agreement shall terminate (the “Initial Period”).

ARTICLE 3 - TARIFFS AND CHARGES

The Shipper shall pay ECA the applicable and valid tariffs and charges for the services rendered or agreed in this Agreement, including all applicable surcharges, pursuant to the General Terms and Conditions, the Regulated Tariff Sheet and the Specific FBSS Terms registered by ECA with the Commission, together with their respective modifications, supplements or replacements, applicable to the service described herein. ECA may make modifications to the terms and conditions of the services subject to the prior approval of the CRE and shall notify the Shipper, as well as of the effective date of the changes.

The Shipper and ECA may agree a Conventional Tariff for a specific term of service in accordance with this Agreement. ECA and the Shipper agree not to initiate any proceeding before the CRE to increase or decrease in any Conventional Tariff stipulated in Exhibit B hereto for the Initial Period.

The Regulated Tariffs for the service are:

Firm Base Storage Service Tariff: ____________ USD/GJ

ARTICLE 4 - SYSTEM OPERATION GAS

Pursuant to the Specific Service Terms, in addition to the billing of the tariffs and charges stipulated in Article 3, ECA shall withhold a percentage of the Quantities of Natural Gas delivered to the Shipper in accordance herewith to be used as System Operation Gas.

ARTICLE 5 - GENERAL TERMS AND CONDITIONS

This Agreement and all the service terms specified herein are subject to the provisions of the Regulated Tariff Sheet, the Specific FBSS Terms and ECA's General Terms and Conditions, which may be modified, supplemented, superseded or replaced subsequently in general or solely in terms of the service described herein. Subject to the approval of the CRE, ECA may make modifications to the terms of the Regulated Tariff Sheet, the Specific FBSS Terms and the General Terms and Conditions pursuant to the Applicable Legal Provisions mentioned therein. The Regulated Tariff Sheet, the Specific Service Terms and the General Terms and Conditions, as may be amended from time to time, shall be included in and form an integral part of this Agreement.

ARTICLE 6 - CANCELLATION OF PREVIOUS AGREEMENT

As of the date(s) stated below, this Agreement supersedes, cancels and extinguishes the following Agreement(s) (if any), signed by and between ECA and the Shipper:

ARTICLE 7 - NOTIFICATIONS

Unless specified otherwise, all notifications sent in relation to this Agreement shall be in writing. The legal domiciles of both ECA and the Shipper are as follows:

ECA *[addresses updated and corrected 1/13/2017]*

Payment: ENERGÍA COSTA AZUL, S. DE R.L. DE C.V.
For the attention of: Billing Department
Sempra LNG & Midstream, LLC
488 8th Avenue, HQ-14, San Diego, CA 92101

Orders and Scheduling: ENERGÍA COSTA AZUL, S. DE R.L. DE C.V.
For the attention of: Asset Management Operations
Sempra LNG & Midstream, LLC
488 8th Avenue, HQ-14, San Diego, CA 92101
BUSINESS DAYS, SATURDAYS AND
SUNDAYS 8 a.m. - 12 p.m. PACIFIC TIME
Telephone Number: 619-696-2776
Fax: 619-696-2392

OTHER TIMES
Telephone Number: 619-696-2776
Fax: 619-696-2393

Other: ENERGÍA COSTA AZUL, S. DE R.L. DE C.V.
For the attention of: Asset Managemen Operations
Sempra LNG & Midstream, LLC
488 8th Avenue, HQ-14, San Diego, CA 92101
Telephone Number: 619-696-2776
Fax: 619-696-2393

SHIPPER

Billing: ________________________________
____

Orders and Scheduling: (1) ______________________________
____

Legal Representatives ______________________________
____

(1) Please provide operational address in addition to mailing address.

ARTICLE 8 – Settlement of Disputes

Any disputes that arise between ECA and the Shipper as a result of the provision of the Storage Service may be resolved, at the discretion of the Shipper, by an arbitration procedure conducted subject to the terms and rules of [______] or the procedure established by the CRE.

The arbitration procedure and the jurisdictional body appointed to hear the dispute shall be registered in the Public Registry stipulated in section XVI of Article 3 of the CRE Law. If said registration has not been made, the arbitration procedure shall be as stipulated in Article 9 of the CRE Law and shall be pursuant to the terms of Title Four, Book Five of the Commercial Code, duly substantiated by the CRE.

When, in accordance with the Federal Consumer Protection Law, Shippers are deemed to be consumers, they may resolve their disputes in accordance with the procedures set forth in said Law.

BASED ON THE FOREGOING, the legal representatives or other duly-authorized persons of both ECA and the Shipper have signed several copies of this Agreement.

SHIPPER

By: ______________________________

____
(Please type or print name in capital letters)

Position: ______________________________

Date: _________ ___, ____

Place: __________________________

ENERGÍA COSTA AZUL, S. DE R.L. DE C.V.

By: ______________________________

____
(Please type or print name in capital letters)

Position: ______________________________

Date ________________ _____, _______

Place: __________________________

EXHIBIT A

The Shipper's Vessels authorized to be used are:

Name	Capacity (cubic meters)

EXHIBIT B

Agreement No.

CONVENTIONAL TARIFF AGREEMENT

The Shipper accepts the Conventional Tariff option in accordance with the General Terms and Conditions and Section 3 of the Specific FBSS Terms and declares its wish to ECA to be billed and agrees to pay the charges specified below for the period commencing __________ ___, _____ and continuing until __________ ___, _________. The Shipper is aware that this option is an alternative to the billing of charges under the General Terms and Conditions and the Specific FBSS Terms, as modified and authorized by the Commission. The Shipper also acknowledges that this option constitutes a waiver of its authority and right to use the Regulated Tariffs are available to it under the General Terms and Conditions and the Specific FBSS Terms.

Conventional Tariff Specification:

ENERGÍA COSTA AZUL, S. DE R.L. DE C.V.

By: ________________________________

____
(Please type or print name in capital letters)

SHIPPER

By: ________________________________

____
(Please type or print name in capital letters)

Position: _________________________________

Date __________________ _____, _______

SUPERSEDES EXHIBIT B DATED: _______________

Attachment R

LNG Studies

Attachment R-1

Weathering of stored Liquefied Natural Gas (LNG)

10th International Conference on Thermal Engineering: Theory and Applications
February 26-28, 2017, Muscat, Oman

Weathering of stored Liquefied Natural Gas (LNG)

Calogero Migliore[1,2], Amin Salehi[1], Velisa Vesovic[1]

[1] *Department of Earth Science and Engineering, Imperial College London, London SW7 2AZ, United Kingdom*
[2] *Repsol, S. A., calle de Méndez Álvaro, 44, 28045, Madrid, Spain*

Abstract

A model for predicting the weathering of LNG stored in containment tanks has been recently developed that allows the temperature of vapor to be different to that of LNG. The model is used to analyze the heat transfer between vapor and LNG, by means of an effective thermal conductivity. The simulation results indicate that the temperature of the vapor phase will be higher than that of the LNG, and that increase is a function of the effective thermal conductivity. Thus, demonstrating that the effective thermal conductivity could be used as a proxy to match the results to measurements. This has important implications for weathering models used in industry, which currently assume isothermal conditions within the containment tanks.

Keywords: LNG, boil-off gas, weathering

1. Introduction

The current consensus is that natural gas will continue to play an important part in the global energy mix [1]. Liquefied natural gas (LNG), is seen by an increasing number of producers and consumers as a viable option for transportation of natural gas. As a valuable energy resource LNG is stored on a commercial scale in large, highly insulated storage tanks at its boiling temperature and slight overpressure. The LNG is stored at cryogenic temperatures for significant durations and inevitable heat ingress from the surroundings into the storage tank will lead to vaporization. The more volatile components (methane and nitrogen) will vaporize preferentially, resulting in weathering of LNG. If left unchecked, the weathering can render the remaining LNG unsellable, because of regulatory requirements. Furthermore, the weathering increases the overall tank pressure and in order to avoid over-pressurization some of the generated vapor is removed, as boil-off gas (BOG). The industry is specifically concerned in minimizing the BOG and ensuring that the weathering does not greatly impact on the LNG quality. In particular weathering prediction is used in planning operations, thus ensuring appropriate allocation of LNG cargoes, its compatibility with stored LNG and avoiding catastrophic events involving stratification, sudden vapor release and rollover. There is thus a need for developing models that can predict the weathering phenomena. This is not an easy task, as interplay between a number of simultaneous phenomena, requires a careful consideration of the heat transfer and thermodynamics of the system.

We have recently developed two models of weathering of LNG in storage, containment tanks [2,3]. In an early model [2] we make use of a standard assumption that the vapor phase above the LNG is at the same temperature as the weathering LNG. We will refer to this model as the 'isothermal' model. Most, if not all of the models available so far [4,5 and references there in] make use of this assumption. However, scant industrial evidence suggests that this is not the case in the commercial LNG storage tanks. Hence, in the later model [3], we did not invoke the assumption of thermal equilibrium and have separated the heat flux entering the LNG from the heat flux entering the vapor section of the storage tank. This has important consequences on the dynamics of the heat transfer, as the heat that enters the vapor phase leads to an increase in the vapor temperature, while the heat influx into the liquid phase leads to evaporation of the LNG. If the process of heat transfer from the vapor to the liquid is slow a temperature difference between the two phases will be established and the vapor temperature will be higher than that of the liquid, which remains at its boiling temperature throughout the weathering. We will refer to this model as the 'non-isothermal' model. The conference presentation will present the results from both models, illustrating the importance of treating both the heat transfer and the thermodynamics correctly. It will demonstrate that the use of a more sophisticated heat transfer model leads to a more realistic estimation of the BOG rate that provides industry with the possibility of implementing less conservative practices with additional cost benefits.

In this paper we focus on the, so far unreported, role of using an effective thermal conductivity as a proxy measure of the efficiency of heat transfer between vapor and liquid that allows for 'bridging' between the isothermal and non-isothermal models.

2. Weathering Model

Figure 1 illustrates the schematic of the LNG storage tank with the emphasis on the relevant heat transfer. The heat ingress from the surroundings, through the lateral wall of the storage tank, is split into two components, Q_{Vin}, and Q_{Lin}, that represent heat influx into the vapor and liquid phases, respectively. The constant heat influx from the thermal slab underneath the storage tank will provide an additional source of heat, Q_{slab}. In the non-isothermal model the LNG will also receive heat from the vapor phase, designated Q_{VL} in Fig. 1. The overall heat ingress will lead to the weathering of LNG measured by the rate of vaporization $\dot{B}_L$. In order to maintain the constant pressure BOG will be released and the rate of vapor removal is designated $\dot{B}$.

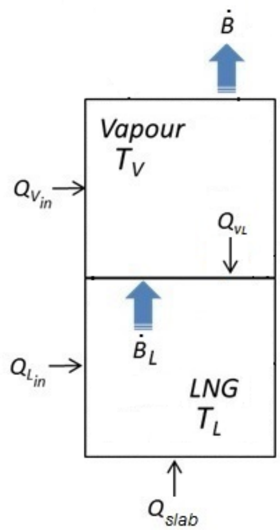

Fig. 1. Schematic of the heat exchange between the surroundings, LNG and vapor

The system is governed by a coupled set of differential energy equations

$$U_V A_V (T_{air} - T_V) - Q_{VL} = \frac{dH_V}{dt} + \dot{B} h_V(T_V) - \dot{B}_L h_V(T_L)$$

$$U_L A_L (T_{air} - T_L) + Q_{VL} + Q_{slab} = \frac{dH_L}{dt} + \dot{B}_L h_V(T_L) \qquad (1)$$

where U is the overall heat transfer coefficient, A is the contact area H and h are the enthalpy and molar enthalpy, respectively, while the subscripts V and L refer to the sections of the tank filled with liquid and vapor, respectively. For the isothermal model Eq. (1) reduces to

$$UA(T_{air} - T) + Q_{slab} = \frac{dH_V}{dt} + \frac{dH_L}{dt} + \dot{B}_L h_V(T) \qquad (2)$$

The right-hand side of Eqs. (1-2) contains only thermodynamic quantities and their evolution with time, and can in principle be obtained from an appropriate thermodynamic model [2,3].

If we take the limiting case that the heat transfer from the vapor phase to LNG is by conduction only, then the thermal conductivity of the vapor phase governs the rate of heat transfer and consequently the temperature of the vapor phase. It is clear that if the thermal conductivity is used as an effective parameter one can simulate, in a simple manner, the effect of convection, if any is present. In the limit of thermal conductivity reaching an infinite value the non-isothermal model will tend to an isothermal one. Furthermore, the effective thermal conductivity offers a straightforward way to match the model prediction to the experimental measurements of the vapor temperature in the real LNG containment tanks, when and if such measurements become available.

3. Results

Here we report on the simulations of weathering behavior of an LNG mixture in order to elucidate the effect of Q_{VL}, by means of effective thermal conductivity acting as a proxy. The commercial mixture in question was termed a 'light LNG' in our previous work [2,3] and it primarily consists of methane, with a small amount of ethane present. The results of weathering behavior are reported for a period of one year and refer to a standard 165,000 m^3 containment tank initially filled with 160,000 m^3 of LNG. We refer the reader to Refs [2,3] for further details of the tank, simulation set-up and the composition of the light LNG.

Figure 2 (a) illustrates that if the heat transfer between the vapor and LNG, Q_{VL}, is by conduction only the vapor temperature will increase by approximately 7.6 K over the period of one year [3]. As we increase the effective thermal conductivity the vapor temperature decreases. For values in excess of 100*k* the temperature increase is of the order of 1 K which approximately corresponds to the temperature increase observed for a case where the heat transfer is by fully-developed natural convection, as reported in Ref [3]. For higher values of *k* the non-isothermal model will tend to an isothermal one and the vapor temperature will tend to the value of the LNG boiling temperature. As far as we are aware no reliable measurements of the vapor temperature in the industrial tanks are available. However, the circumstantial evidence tends to support a conduction case. Until such measurements become available it is not possible to fully validate the model, nor is it possible to use effective thermal conductivity to perform the matching, in case such a matching is necessary.

Figure 2 (b) illustrates the behavior of the BOG rate as a function of weathering duration. We observe that irrespective of the magnitude of the effective thermal conductivity the BOG rate decreases over the analyzed period. As indicated before [3] the observed decrease can be entirely attributed to a decrease in a wetted contact wall area. As LNG weathers, the liquid level drops and the heat transfer from the surroundings decreases. It is interesting to note that over the period of a year the choice of a heat transfer mechanism results in a change of overall BOG of 170 tons which represents approximately 4.4% of the total BOG generated.

Figures 2 (c) and 2(d) illustrate the evolution of vapor-liquid heat transfer and overall heat transfer from the surroundings into LNG, respectively. A comparison at 52 weeks shows that the vapor-liquid heat transfer by conduction has the potential to decrease Q_{VL} by up to 3 times or the cumulative overall heat transfer across the 12-month period by 47%. This decrease could result in a notable impact on the overall rate of LNG heat input, Figure 2 (b), particularly at higher values of *k* and at later times during the weathering process. Similarly, a comparison at 52 weeks reveals that Q_{VL} contributes between 2.4% to 6.9% depending on the value of *k*, to the total heat input to LNG,

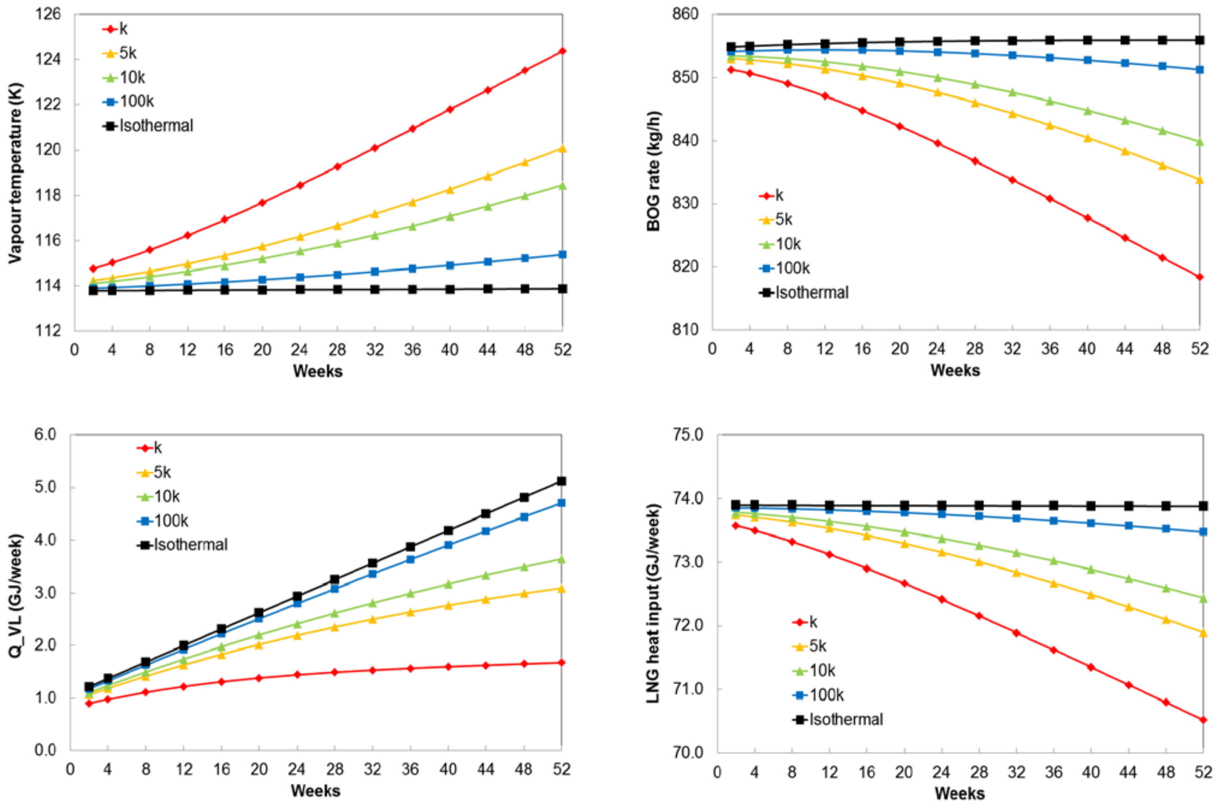

Fig. 2. The effect of using the effective thermal conductivity on: (a) Vapor temperature, T_V; (b) BOG rate; (c) Vapor-liquid heat transfer, Q_{VL}, and (d) Overall LNG heat input as a function of weathering duration.

4. Conclusion

Use is made of a recently developed model that allows for a variation in the temperature of the vapor blanket in contact with weathering LNG, stored in a containment tank. The model is used in a predictive mode to analyze the heat transfer between vapor and LNG by means of effective thermal conductivity. The results indicate the effective thermal conductivity is a good proxy for the heat transfer mechanism. The simulations demonstrate that the vapor temperature increases in line with circumstantial industrial evidence and that BOG decreases, as a function of weathering time.

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Attachment R-2

Problem of Boil - off in LNG Supply Chain

REGULAR PAPERS

Problem of Boil - off in LNG Supply Chain

Đorđe Dobrota, Branko Lalić, Ivan Komar

This paper examines the problem of evaporation of Liquefied Natural Gas (LNG) occurring at different places in the LNG supply chain. Evaporation losses in the LNG supply chain are one of the key factors for LNG safety, technical and economic assessment. LNG is stored and transported in tanks as a cryogenic liquid, i.e. as a liquid at a temperature below its boiling point at near atmospheric pressure. Due to heat entering the cryogenic tank during storage and transportation, a part of the LNG in the tank continuously evaporates creating a gas called Boil-Off Gas (BOG), which changes the quality of LNG over time. The general methods of handling and utilization of the Boil-Off Gas at different points in the LNG supply chain are presented. Attention is given to the issue of LNG energy content transferred during loading and unloading of LNG tankers, as well as to the Boil-Off Gas generated by evaporation of the cargo during maritime transport. The results presented in the paper have been derived from the scientific research project 250 - 2502209 - 2366 „Management of Ship Power Systems under Fault Conditions and Failure" supported by the Ministry of Science, Education and Sports of the Republic of Croatia.

KEY WORDS:
~ Liquefied
~ Natural gas
~ Supply chain
~ Boil-off gas
~ Gas utilization and use
~ LNG energy content

University of Split, Faculty of Maritime Studies, Zrinsko-Frankopanska 38, 21000 Split, Croatia
E-mail: ddobrota@pfst.hr, blalic@pfst.hr, ivan.komar@pfst.hr

1. INTRODUCTION

Owing to the ever increasing share of the natural gas in the world consumption of power sources, international maritime traffic with liquefied natural gas is continuously growing, with even greater expectations for the future.

A large portion of natural gas is located far from large customers. Most of the international trade in natural gas, depending on the distance, takes place by pipelines and LNG ships in liquid form, and rarely in special heat insulated tanks by rail or road transportation. Due to lower investment costs, the transportation of gas by pipelines is preferred up to distances of about 2000 km. After that, the costs grow significantly faster than the costs of transportation of gas in liquid form, with a tendency for change if advances in technology are made. The LNG market has greater flexibility because, in general, the capacity of one exported unit may cover the capacity needed for two or three imported units.

Furthermore, it is clear from the current worldwide liquefied natural gas market that LNG tends to be exported to regions where gas prices are higher (Asia, USA and Europe), and this flexibility does not exist or exists to a lesser extent in transportation by pipelines.

LNG has been steadily increasing its market share in the global gas trade. According to data from the IEA (International Energy Agency) statistical review for 2010, the global LNG market now accounts for about 9% of demand for natural gas or 299 billion m^3.

Liquefied natural gas is stored and transported in tanks as a cryogenic liquid, i.e. as a liquid at a temperature below its boiling point. Just like any liquid, LNG evaporates at temperatures above its boiling point and generates BOG. Boil-off is caused by the heat ingress into the LNG during storage, shipping and loading/unloading operations. The amount of BOG depends on the design and operating conditions of LNG tanks and ships.

The increase in BOG increases the pressure in the LNG tank. In order to maintain the tank pressure within the safe range, BOG should be continuously eliminated. In the LNG supply chain, BOG can be used as fuel, re-liquefied or burned in a gasification unit. Furthermore, the more volatile components (nitrogen and methane) boil-off first, changing LNG composition and quality over time. This phenomenon, known as ageing, is especially important in LNG trade since LNG is sold depending on its energy content, i.e. specification at the port of unloading determined depending on the volume of the LNG transferred, its density and heat value.

This paper deals with the problem of boil-off in the LNG supply chain and its main causes. The general methods of handling and utilization of BOG at different points in the LNG supply chain are presented. Furthermore, the paper presents a calculation method used in the LNG industry to determine LNG energy content transferred during loading and unloading of LNG tankers.

2. FEATURES OF LNG AND ITS SUPPLY CHAIN

Liquefied natural gas is a liquid substance, a mixture of light hydrocarbons primarily composed of methane (CH_4, 85-98% by volume), with smaller quantities of ethane (C_2H_6), propane (C_3H_8), higher hydrocarbons (C4+) and nitrogen as an inert component. The composition of LNG depends on the traits of the natural gas source and the treatment of gas at the liquefaction facility, i.e. the liquefaction pre-treatment and the liquefaction process. It can also vary with storage conditions and customer requirements (Benito, 2009; British Petrol and International Gas Union, 2011).

Namely, LNG producers determine the quality of their LNG based on the composition of field gas and more importantly, market demand.

Liquefied natural gas is a colourless, odourless, non-corrosive and non-toxic liquid, lighter than water. Typical thermo-physical properties of LNG are presented in Table 1.

Table 1.
Thermo-physical properties of LNG.

Parameter	Value
Boiling point	-160°C do -162°C
Molecular weight	16 – 19 g/mol
Density	425 - 485 kg/m^3
Specific heat capacity	2,2 – 3,7 kJ/kg/°C
Viscosity	0,11 – 0,18 mPa•s
Higher heat value	38 - 44 MJ/m^3

LNG may be classified in accordance with several criteria: Density, Heat Value, Wobbe Index, Methane or Nitrogen amount, etc. The parameter most commonly used for its classification is density. Accordingly, we differentiate between heavy, medium or light LNG's. The typical composition and density of three typical LNG qualities are depicted in Table 2.

Table 2.
Classification of LNG by density (Sedlaczek, 2008).

Composition (%)	LNG Light	LNG Medium	LNG Heavy
Methane	98.00	92.00	87.00
Propane	1.40	6.00	9.50
Propane	0.40	1.00	2.50
Butane	0.1	0.00	0.50
Nitrogen	0.10	1.00	0.50
Density (kg/m^3)	427.74	445.69	464.83

The LNG supply chain consists of extraction and production of natural gas, liquefaction, marine transportation of LNG, and LNG storage, re-gasification and delivery of natural gas to consumers.

The extraction of natural gas from the earth's surface is the first step in the supply chain and includes drilling and gas extraction. The gas produced can come from a gas field (non-associated gas) or be produced along with oil (associated gas). The distinction between associated and non-associated gas is important because associated gas must have liquefied petroleum gas (LPG) components (i.e., propane and butane) extracted to meet the heat value specifications of the LNG product. Natural gas derived directly from the gas field is called "raw" gas. Such gas is associated with a number of other compounds and gases that may have an adverse effect on liquefaction and combustion.

The produced natural gas is transported by pipelines from gas fields to a liquefaction facility, located in large areas along the coast. One of the primary purposes of liquefaction plants is to ensure the consistent composition and combustion characteristics by cooling and condensing natural gas to allow its loading onto tankers as LNG and delivery to the end user. Therefore, their design must include several parallel processing modules (trains) for the preparation and liquefaction of natural gas, LNG storage tanks, facilities for loading LNG tankers, general purpose facilities, i.e. sea water pumping stations, electricity generation plants, nitrogen production plants, compressor stations, workshops and system security.

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The technical processes of purification of gas from harmful components to obtain gas acceptable for use and liquefaction are performed in the preparation trains. Therefore the following need to be removed prior to liquefaction: components that would freeze at cryogenic process temperatures during liquefaction (carbon dioxide-CO_2, water and heavy hydrocarbons), components that must be removed to meet the LNG product specifications (hydrogen Sulfide-H_2S), corrosive and erosive components (mercury), inert components (helium and nitrogen) and oil. Typical specifications of gas for liquefaction are less than 1 ppm of water, less than 100 ppm CO_2 and less than 4 ppm H_2S.

Following the removal of most contaminants and heavy hydrocarbons from the feed gas, the natural gas is subjected to the liquefaction process. Natural gas is converted to its liquefied form by the application of refrigeration technology making it possible to cool the gas down to approximately -162°C when it becomes a liquid.

The produced LNG is stored in cryogenic tanks below the boiling point at the pressure of 0.05-0.2 bar until an LNG tanker arrives to transport the product. Upon the arrival of the tanker, LNG from the storage tank is loaded from the loading plant into the LNG tanker, which will transport the gas to the receiving terminal. For safety reasons, storage tanks at loading and receiving terminals in which liquefied gas is stored usually consist of two tanks designed to be fully loaded. The inside of the container in which liquefied gas is stored is usually made of stainless steel resistant to low temperatures. The outer tank is made of pre-stressed concrete and designed to fully contain LNG in case of spillage and be fully loaded in the event of damage to the inner tank. Apart from safety aspects, LNG tanks are also designed to minimise the ingress of heat into the tanks to prevent the boiling (evaporation) of a fraction of the LNG. The usual tank volumes range from 80.000 to 160.000 m^3.

Step three in the LNG supply chain is the transportation of liquefied natural gas to the receiving terminal. Liquefied natural gas is carried by specially designed ships, LNG tankers, in specially insulated tanks inside the hull at near atmospheric pressure, at the temperature of -163°C. In these tanks, the cargo is kept fully refrigerated using insulation and the effect of a small amount of evaporated cargo generated during the voyage. LNG tankers are a combination of classic ship design, special materials and advanced containment systems for handling cryogenic cargo. Today there are four containment systems in use on these vessels. Two of the designs are of the self supporting type, namely Moss spherical tanks and SPB tanks (Self supporting Prismatic type B tank). The other two are of the membrane type and today their patents are owned by Gaz Transport & Technigaz (GTT). Operating pressure in containment tanks ranges between 0.05 and 0.12 bar, at which LNG cargo reaches the equilibrium temperature corresponding to the operating pressure. All LNG tankers have double hulled design, which greatly increases the reliability of cargo containment in the event of grounding and collision.

The majority of existing LNG tankers have the cargo capacity ranging between 120,000 m^3 and 150,000 m^3, with some ships having the storage capacity of up to 264,000 m^3. Due to the required high-capacity, re-liquefaction plants for evaporated cargo are generally not installed into these vessels. Since evaporated cargo provides a source of clean fuel, most LNG tankers have a steam-turbine propulsion system. The reason is high reliability and safe use of evaporated cargo that burned in the boilers. Q-flex type tankers having the capacity of 210,000-216,000 m^3 and Q-max tankers having the capacity of 260,000-270,000 m^3 constructed with re-liquefaction plants are exceptions. These vessels are intended for long distance transportation of liquefied natural gas, for example from Qatar to the United Kingdom or the United States. Loading and unloading rates vary between 12,000 and 14,000 m^3 per hour depending on the size of the LNG tanker. During loading, according to IMO (International Maritime Organization) requirements each tank is filled to 98% of its total volume. The remaining 2% of storage volume is required to prevent any entry of the liquid into ventilation pipeline and from spilling into the surrounding hull structure. Between 98.5 and 99% of the cargo is unloaded. The remaining quantity of LNG remaining on board after unloading, called a "heel", is used during the ship's ballast voyage to keep the tanks cold, as well as fuel for the propulsion system and the ship's energy system.

The receiving terminal (sometimes called a re-gasification facility) is the fourth and last component of the LNG supply chain. Its basic task is to receive and unload liquefied natural gas from LNG tankers, store, vaporise LNG and distribute the gas into the distribution network (Dundović et al., 2009). The receiving terminal is designed to deliver the specified quantity of gas into the distribution pipeline and maintain a reserve quantity of LNG. Therefore, its design must include the following elements: a system for receiving and discharging LNG tankers, storage tanks, a re-gasification plant, a control system to control the LNG boil-off gas, supplying their own consumption (utilities), equipment and facilities support. Since natural gas is odourless, the odourisation of the re-gasified natural gas is required in many regions and countries before its distribution to consumers. An atypical odorant is mercaptan or tetrahydrothiophene (British Petrol and International Gas Union, 2011).

3. BOIL-OFF IN THE LNG SUPPLY CHAIN

Liquefied natural gas is stored and transported in tanks as a cryogenic liquid, i.e. liquid at a temperature below its boiling point. Due to heat leakage into LNG and its cryogenic nature, during storage, shipping and loading/unloading modes LNG continuously evaporates. Inside the tanks, LNG exists in an equilibrium between a thermodynamic liquid and vapour, depending on the given pressure and temperature. Since pressure in the tank is low, the multi-component mixture system acts in keeping with Raoult's law (Figure 1). In Figure 1, p is the total vapour pressure of the vapour phase, p_i^{sat} the saturation pressure of a pure component i in the liquid phase at temperature T, y_i and x_i the fraction of component i in the vapour phase and the liquid phase and K_i the dimensionless equilibrium ratio. Therefore, any heat ingress causes evaporation of the liquid on its surface without any visible bubbles. Namely, to keep the temperature constant and appropriate for tank pressure, LNG will cool itself (auto-refrigeration) by evaporating a small portion of the LNG and generated BOG (Dimopoulos and Frangopoulos, 2008; British Petrol and International Gas Union, 2011).

Vapor

at T, p, y_i

$$y_i \cdot p = p_i^{sat}(T) \cdot x_i$$

$$K_i = \frac{p_i^{sat}(T)}{p} = \frac{y_i}{x_i}$$

LNG

at T, p^{sat}, x_i

Figure 1.
General criteria for the vapour-liquid equilibrium for LNG as multi-component mixture.

The quantity of BOG depends on the design and operating conditions of storage tanks and a ship's cargo tanks. The LNG supply chain with boil-off source is shown in Figure 2.

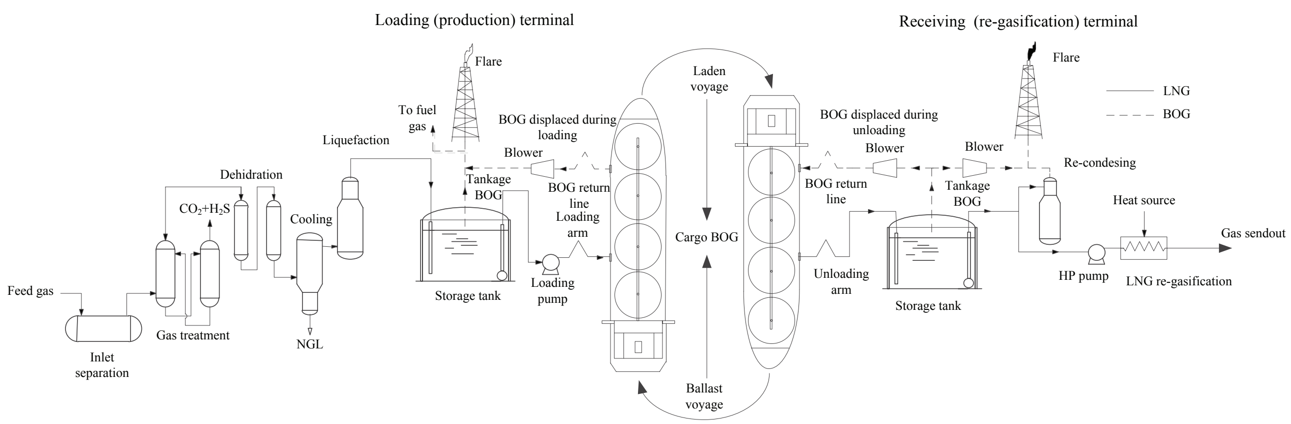

Figure 2.
LNG supply chain and boil-off source.

The increase of BOG in storage and ship's tanks increases the LNG operating tank pressure. In order to maintain the operating tank pressure within the safe range, BOG should be continuously removed. At the loading terminal, BOG is usually used as fuel in the liquefaction plant production process. At receiving terminals, it is either burned or sent to the re-gasification plant using BOG compressors.

During the journey of an LNG tanker, depending on the type of the propulsion system, BOG can be utilized as fuel, re-liquefied or burned in a gasification unit. Since the boiling points of different components of LNG widely vary, from -196ºC to +36ºC, the rates of evaporation of more volatile components, such as Nitrogen and Methane, are higher than those of heavier components, i.e. ethane, propane and other higher hydrocarbons (Sedlaczek, 2008). Therefore, the quality and properties of LNG steadily change over time. This slow but continuous process is called ageing or weathering of LNG (Faruque, Zheng Minghan and Karimi, 2009; Głomski and Michalski, 2011; Benito, 2009; British Petrol and International Gas Union, 2011).

In the LNG supply chain, LNG is sold at the receiving terminal, depending on its energy content typically measured in GJ, GWh or MMBTU. Ship charterers, mostly oil & gas or energy companies, buy LNG cargo at the loading terminal at a certain production cost, i.e. Free On Board (FOB) price and sell LNG at the receiving terminal at a higher Cost-Insurance-Freight (CIF) price which includes the cost of fuel, insurance, port charges and charter rate. Since BOG reduces the quantity of cargo delivered by LNG tankers and increases the heat value of LNG in storage and ship's tanks, the quantity of BOG is a key factor for the technical and economic evaluation of the LNG supply chain.

3.1. Boil-off of LNG in storage tanks during holding mode

The holding mode is referred to as the period between loading/unloading of LNG tankers (Sedlaczek, 2008). At loading and receiving terminals, LNG is stored in cryogenic storage tanks at standard operating pressure ranging from 0 to 0.15 bar above atmospheric pressure. There are two main sources of boil-off gas during storage of LNG in holding mode, namely heat ingress into storage and pipes from the surroundings and changes in the ambient (barometric) pressure.

Heat ingress from the surroundings means that BOG is generated continuously in the tanks. In order to reduce boil-off, storage tanks have multi-layered insulation that minimizes heat leakage. The driving force for heat ingress into an LNG tank is the difference between the outside temperature and tank temperature. Due to the large temperature differences between the medium and the environment, the heat ingress into the LNG through floor, walls and roof of storage tanks (Figure 3) may occur in three ways: by conduction, by convection and by radiation. Storage tanks are typically designed to reduce the ingress of heat from the surroundings and solar heating so that vaporisation is less than 0.05 % of the total tank content per day, although this can vary from 0.02 to 0.1% (British Petrol and International Gas Union, 2011).

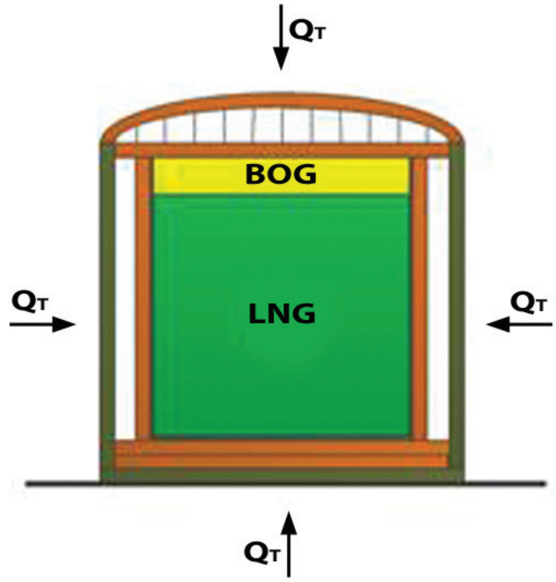

Figure 3.
Heat ingress into storage tank.

At loading and receiving terminals, a typical loading/unloading system consists of loading/unloading arms, circulation pipelines transferring LNG from ships to storage tanks and vice versa, pumps, etc. During the holding mode, a small portion of LNG circulates through the pipelines to maintain their cryogenic temperature. Circulating through the pipeline, LNG absorbs the heat from the surroundings and the heat generated from pumping, turbulent flow, and line friction. The absorbed heat generates additional BOG in storage tanks. This quantity of BOG depends on the length of the pipeline and the power of the pumps (Faruque et al., 2009; Sedlaczek, 2008; British Petrol and International Gas Union, 2011).

In storage tanks, a significant increase in the boil-off rate can cause a drop in atmospheric pressure. As atmospheric pressure drops, tank pressure and bubble point temperature of LNG decrease. To equilibrate with this lower pressure, the temperature of the LNG in the tank has to decrease by approximately 0.1°C for every 0.01 bar drop (Sedlaczek, 2008). This favours greater boil-off because the only way to decrease the temperature in the tank is to release some of the liquid into gas. A drop in atmospheric pressure only has effect if it is rapid, because it is only then that it can cause a significant increase in the boil-off rate from the storage tank.

BOG produced during holding mode in storage tanks is usually called tankage BOG (Faruque et al., 2009). When heat is added into LNG, the vapour pressure inside the tank increases. In order to maintain the tank pressure within the safe range, tankage BOG should be removed by compressors.

At loading terminals, BOG is usually compressed and exported to the plant fuel system. At receiving terminals, BOG is compressed in a re-gasification plant where it can be compressed and exported as gas or liquefied and exported as gas. In case of condensation problems, the vapour is burnt.

3.2. Boil-off during loading/unloading mode

The loading/unloading mode is the period when an LNG tanker is moored to the jetty at loading and receiving terminals and connected to onshore storage tanks with loading/unloading arms and insulated pipelines.

Modern LNG terminals are designed to accept LNG-tankers having the capacity from 87,000 m^3 to 270,000 m^3. Loading or unloading facility is of a size compatible with the standard loading rate of 10,000-12,000 m^3 per hour, allowing LNG tankers to load or unload 125,000-270,000 m^3 within 12-18 hours, depending on the size of the ship (Dundović et al., 2009; Faruque et al., 2009).

BOG generated during loading and unloading of an LNG tanker is typically 8-10 times greater than tankage BOG (Benito, 2009). The reason is mainly the return of vapour from the ship's or storage tanks. The main sources of BOG released during the ship loading/unloading process are presented in Table 3.

LNG tanker is loaded by the terminal's pumps and unloaded by the ship's pumps. During the loading/unloading operations, large quantities of LNG are pumped from the ship in a short time. This causes rapid change of pressure. During the loading process, the loaded LNG displaces an equivalent quantity of vapour in the ship's empty cargo tanks. In order to maintain the cargo tanks at their operating pressure, the displaced vapour from the ship's cargo tanks is returned to the storage tank via the vapour return line. During the cargo unloading process, the vapour pressure of the boil-off gas generated during loading and unloading is of short duration at the high flow rate usually taking 12-18 hours, depending on the terminal's loading/unloading capacity. This flow rate depends on the pressure and temperature differences between the ship's tanks and storage tanks.

LNG tanker cargo tanks are maintained by returning vapour from the storage tanks (displaced by the terminal's blowers) to fill the ullage space in tanks. With this balanced system, under normal circumstances no BOG will be released to the atmosphere from ship or shore.

The energy used by the terminal's and ship's pumps greatly influences the boil-off rate. A typical LNG tanker having the capacity of 130,000 m^3 requires over 3,000 kW of pumping energy. During pumping, due to friction and turbulence, almost all of this energy is converted into heat adsorbed by the LNG. This large amount of heat is sufficient to heat the LNG by as many as 0.5°C. To provide for the new tank conditions, LNG cools itself down by evaporating a small portion of LNG. This process is called auto - refrigeration and can generate approximately 20,000 kg per hour of BOG (Sedlaczek, 2008). Although the circulation pipelines are well insulated, some heat from the surroundings always leaks into LNG. The extent of the heat leak depends on pipeline length. If the pipeline is relatively short (under 1 km), the heat components from LNG pumping and heat leaks into pipelines are relatively small and generate typically around 5% of total BOG. In case of greater lengths, there is a significant increase in the quantity of BOG. For example, if the pipeline is 7 km long, the quantity of BOG generated by these heat components is estimated at 45% of total BOG (British Petrol and International Gas Union, 2011).

Table 3.
Main factors affecting the quantity of BOG released during the ship loading/unloading process.
Source: British Petrol and International Gas Union, (2011).

BOG generated during loading process	BOG generated during unloading process
• Vapour return from ship's tanks. • Heat transferred to LNG by loading pumps. • Heat leak into LNG from pipes and equipment. • Cooling down of the ship's manifold and loading arms. • Cooling down of jetty lines prior to loading if not continuous. • Mixing of loaded LNG with the initial amount of LNG (heel). • Cooling down of ship's tanks if necessary.	• Vapour return to ship's tanks. • Heat transferred to the LNG by the ship's pumps. • Heat leak into the LNG through the pipes and equipment. • Higher ship's operating pressure than the LNG storage tank . • Cooling down the ship's manifold and unloading arms prior to unloading. • Cooling down of jetty lines prior to unloading if not continuous. • Mixing of unloaded LNG with existing stock of different quality.

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If a ship's tanks are warm, they need to be cooled down prior to loading. The cooling down of a ship's tanks may be required prior to loading if an LNG tanker is returned with insufficient heel, after dry-docking, off-hire or during initial commissioning. The cool down is carried out by initial quantities of LNG, which is evaporated when it comes into contact with the warm sides of the tanks. In this case, the loading process takes longer.

During the unloading of an LNG tanker, differences in operating pressures between the ship's and the terminal's storage tanks can also influence the quantity of BOG. The LNG cargo attains an equilibrium temperature dependent on the cargo tank pressure. If operating pressure in the ship's tanks is by 0.01 bar higher than in the storage tank, the temperature of LNG in cargo tanks will be higher by approximately 0.1°C than in the storage tank. To establish a new equilibrium, a small portion of the LNG in the storage tank will be evaporated to cool itself down. For example, if the absolute pressure of an operating cargo tank is 1.060 bar and the absolute pressure of an operating storage tank is 1.050 bar, than at the typical unloading rate of 12,000 m^3 per hour, the difference of 0.01 bar will result in a 3,600 kg per hour boil-off (Sedlaczek, 2008). The mixing of unloaded LNG with existing stock of a different quality at LNG receiving terminals can cause stratifications and rollover processes in storage tanks. Stratification refers to the formation of LNG layers of different densities within LNG storage tanks. Rollover refers to the spontaneous rapid mixing of layers and release of LNG vapours from a storage tank caused by stratification.

During the ageing (weathering) process, the density of LNG gradually increases in the storage tanks. When LNG of different composition (density) is injected into the tank, LNG may stratify. The stratification in the tank is characterized by two homogenous layers of different density and temperature, separated by a buffer zone, called the thick interface layer. The upper layer is composed of the liquid less dense than the bottom layer. In the tank, these two layers may form a steady interface layer, i.e. stable stratification. However, due to the ingress of heat into LNG in the tank, the lower layer can eventually reach a temperature at which its density is reduced to such an extent that the interface becomes unstable. This process is intensified by the movement of heavier components from the lower layer to the top layer and the result is a sudden release of heat in the lower layer and an increase in vaporization. This leads to a spontaneous rapid mixing or rollover. In case of rollover, if LNG in the bottom layer is superheated due to the conditions in the tank's vapour space, the rollover can be accompanied by a transient high rate of vapour production that can be 10 to 30 times greater than the tank's normal gas boil-off rate and over-pressurisation of the tank.

The knowledge of LNG quality at any time before unloading helps the operators of the receiving terminals to take, in advance, actions which will prevent stratification and consequently, the rollover.

3.3. Boil-off during ship's voyage

Most of BOG is generated during transportation of LNG by ships. BOG released during the voyage of an LNG tanker may occur due to the following reasons (Faruque et al., 2009; Głomski and Michalski, 2011; Sedlaczek, 2008; British Petrol and International Gas Union, 2011):

- the ingress of heat into cargo tanks due to the difference between the temperature in the cargo tanks and temperature of the environment,
- due to the cooling of a ship's tanks during ballast voyages, achieved by occasional spraying of LNG in the upper part of the tank,
- due to the sloshing of cargo in partially filled tanks due to the action of waves, causing friction on the inner wall of the tank creating an additional thermal effect.

Therefore, the quantity of BOG during a ship's voyage changes depending on the changes in ambient temperature, sea temperature, sea roughness and cargo tank's contents.

Heat ingress is the main reason for the generation of BOG on ships. In maritime transportation of LNG, the quantity of evaporated cargo is normally presented as loss expressed as a percentage of total volume of liquid cargo during a single day, i.e. as Boil-Off Rate (BOR). This value can be calculated by the expression:

$$BOR = \frac{V_{BOG} \cdot 24}{V_{LNG} \cdot \rho} = \frac{Q \cdot 3600 \cdot 24}{\Delta H \cdot V_{LNG} \cdot \rho} \cdot 100 \qquad (1)$$

where *BOR* is in %/day, V_{BOG} volume of BOG in m^3/s, V_{LNG} volume of LNG in cargo tanks in m^3, ρ density of LNG in kg/m^3, Q heat exchange in *W*, and ΔH latent heat of vaporisation in J/kg.

Typical BOR caused by heat ingress for newer LNG tankers ranges from 0.10 to 0.15% for laden (loaded) voyage and from 0.06 to 0.10 % for ballast voyage (Głomski and Michalski, 2011; Sedlaczek, 2008; International Group of Liquefied Natural Gas Importers, 2011).

Cooling of a ship's tanks during ballast voyages is used to reduce the growing temperatures in cargo tanks. The cooling is achieved by sporadic spraying of LNG into the top part of the tank by pumping LNG from the bottom of the tank. LNG in contact with the warm sides of the tank evaporates and generates BOG.

In rough seas, hull movement causes the sloshing of LNG in the partially filled cargo tanks. Sloshing transfers kinetic energy from the waves into cargo tanks, causing friction and heating effect. This additional heating effect produces BOG.

During a ship's voyage BOG can be utilized as fuel, re-liquefied or burned in a gasification unit. Since BOG mostly consist of methane, it is lighter than air in ambient temperature. This allows the safe handling and utilization of BOG. Therefore, LNG is only liquid gas cargo allowed by IMO to be used as a fuel for ship's propulsion and energy systems (McGuire and White, 2000). Due to the simplicity of burning BOG in boilers and high reliability of steam turbine propulsion systems, a majority of LNG tankers are powered by steam turbines.

The continuous growth of LNG marine transportation caused a rapid increase of the capacity of newly ordered LNG tankers (Dimopoulos and Frangopoulos, 2008). However, since BOG is a part of the valuable LNG product and bunker oil is more efficient, the LNG industry recently crossed over to other propulsion systems, namely dual fuel diesel or diesel-electric propulsion systems together with BOG re-liquefaction plant (Dimopoulos and Frangopoulos, 2008; MAN Diesel A/S-LNG Carriers with ME-GI Engine and High Pressure Gas Supply System, 2009). The reason is the superior efficiency of diesel engines. These systems are installed in LNG tankers intended for long distance transportation of liquefied natural gas. Since fuel oil prices are currently high, operators are considering burning boil-off gas instead of utilising 100 % HFO, DO or gas oil.

On the basis of observations of typical BOR on LNG tankers in exploitation, it is estimated that boil-off gas equals about 80-90 % of the energy needed for the LNG tanker at full power output (MAN Diesel A/S- LNG Carriers with ME-GI Engine and High Pressure Gas Supply System) in laden voyage, and 40-50% in ballast voyage. Therefore, additional fuel oil is required or alternative forced boil-off gas must be generated. Most modern LNG tankers have forcing vaporisers which vaporise additional BOG to allow the ship to run on BOG alone. The use of forcing vaporisers depends on relative fuel economics and charterer preference (MAN Diesel A/S- LNG Carriers with ME-GI Engine and High Pressure Gas Supply System, 2009). It should be noted that during the course of the ship's voyage, the ageing process increases the heat value of BOG. With the passage of time, this fact reduces the need for additional quantity of forced BOG (Sedlaczek, 2008).

For safety reasons, BOG can be released into the atmosphere or burnt in a gas combustion unit (also called thermal oxidizer). The decision on the choice of an appropriate method depends on many primarily safety, economic and legal factors.

4. LNG ENERGY CONTENT

LNG is sold depending on its energy content which is typically measured in GJ, GWh or MMBTU (British Petrol and International Gas Union, 2011; International Group of Liquefied Natural Gas Importers, 2011).

LNG is purchased by the charterer (mostly oil & gas or energy companies) at FOB price at the loading terminal and sold at a higher CIF price at the receiving terminal.

Used LNG cargo and LNG cargo lost due to boil-off reduce the amount of cargo delivered by an LNG tanker to the receiving terminal. Furthermore, ageing decreases the percentage content of the lighter boiling point components (Methane, Nitrogen) and increases the percentage content of the higher boiling point components (heavy components) in the LNG remaining in ship's tanks (Głomski and Michalski, 2011). Therefore, the unloaded LNG has a lower percentage content of nitrogen and methane and higher content of ethane, propane and butane than the loaded LNG.

Since the composition of LNG cargo constantly changes during a ship's voyage, its quality and properties also constantly change.

The establishment and calculation of the quantity of energy of LNG transferred between LNG ships and LNG terminals is performed on both terminals. This procedure is called *"Custody transfer"* and involves the activities and measurements taken both on the LNG tanker and on the terminal jetty. Custody transfer is contractually agreed between the LNG buyer and seller.

The determination of the transferred energy is executed together with the measurement and calculation of some parameters, i.e. liquid volume, liquid density and heat value (British Petrol and International Gas Union, 2011; International Group of Liquefied Natural Gas Importers, 2011).

The transferred energy can be calculated with the following formula:

$$E = (V_{LNG} \cdot \rho_{LNG} \cdot GCV_{LNG}) - E_{GD} \pm E_{GE} \tag{2}$$

where E is total net energy transferred from loading terminal to the LNG tanker or from the LNG tanker to the receiving terminal in kJ, V_{LNG} the volume of LNG loaded or unloaded in m^3, ρ_{LNG} the density of LNG loaded or unloaded in kg/m^3, GCV_{LNG} gross caloric value of the LNG loaded or unloaded in J/kg, E_{GD} net energy of the displaced gas from LNG tank in J, E_{GE} energy of the gas used by LNG tanker as fuel (consumed in the engine room) at the port in J.

The volume of LNG loaded V_{LNG} can be calculated using the following expression:

$$V_{LNG} = C - V_{RH} \tag{3}$$

where C is the loading capacity of the LNG tanker in m^3 and V_{RH} the remaining LNG for cargo tank cooling (heel) during ballast voyage in m^3.

The volume of LNG unloaded V_{LNG} can be obtained using the following expression:

$$V_{LNG} = L_{LNG} - TL_{BOG} - V_H \tag{4}$$

where L_{LNG} is the volume of LNG loaded into the ship in m^3, TL_{BOG} total used or lost LNG (BOG) during laden voyage in m^3 and V_H is minimum of LNG for cargo tank cooling (heel) during laden voyage in m^3.

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The calculation used to determine LNG volume is based on the level, temperature and pressure measurements obtained from the ship's instruments, taking into account the calibration and correction tables to compile a report meeting the CTS (Custody Transfer Survey). Lately, the taking of volume measurements has become automated through the LNG tanker's custody transfer measurement system (Benito, 2009; British Petrol and International Gas Union, 2011; International Group of Liquefied Natural Gas Importers, 2011).

LNG density can also be determined by measuring its average value directly in the LNG tanker's tank by means of densitometers or by calculation from the measured composition of LNG transferred and the temperature of LNG measured in the LNG tanker's tanks.

The calculation is made by means of mathematical model equations of state connecting pressure, temperature and volume, widely used in the LNG industry. The most widely used method is the revised KLOSEK-McKINLEY method according to standard ASTM D 4784-93 and ISO 6976. This method is based on empirical evaluation of molar volume of the mixture in the thermodynamic state of the LNG considered. The density of LNG is calculated as follows:

$$\rho = \frac{M_{mix}}{V_{mix}} = \frac{\sum_{i=1}^{n} x_i \cdot M_i}{\sum_{i=1}^{n} x_i \cdot V_i - \left[k_1 + (k_2 - k_1) \cdot (x_{N2}/0.0425) \right] \cdot x_{CH_4}} \tag{5}$$

where M_{mix} is molecular weight of the mixture in g/mol, V_{mix} molar volume of the mixture in m^3/mol, x_i the molar fraction of component i in mol/mol, M_i molecular weight of component i in g/mol, V_i molar volume of the component i at the temperature of the LNG in m^3/mol, k_1 and k_2 correction factors, x_{N2} molar fraction of nitrogen in mol/mol and x_{CH_4} molar fraction of methane in mol/mol.

The calculation of volume correction factors k_1 and k_2 at a given temperature is derived by interpolation of their two known values and with respect to temperature and molecular weight.

Upper Heat value (UHV) or Gross Caloric Value (GCV) is the thermal energy produced by the complete combustion of a unit of volume or mass of the gas (vaporised LNG) in the air, at the constant absolute pressure of 1.01325 bar and at temperature T_h at which the water formed during the combustion condenses. In the case of volumetric GCV, the unit of volume of gas is considered at the gas volume metering conditions of temperature T_v and pressure p_v. The GCV can be determined by calorimeter measurements or by computation based on the composition of the gas (vaporised LNG) in the reference condition.

There are several standards that can be used to calculate GCV, such as ISO6976, ASTM 3588 GPA2145 etc. Custody transfer should state the standards and reference conditions used, namely the combustion temperature and pressure.

According to the ISO697 standard, GCV_{LNG} is calculated with the following formula (International Group of Liquefied Natural Gas Importers, 2011):

$$GCV_{LNG} = \frac{\sum_{1}^{n} x_i \cdot GCV_i}{\sum_{1}^{n} x_i \cdot M_i} \tag{6}$$

where GCV_{LNG} is mass gross calorific value in J/kg, x_i molar fraction of component i in mol/mol, GCV_i molar gross calorific value of component i in J/mol, M_i molecular mass of component i in g/mol. The physical constants GCV_i and Mi being specified in coherent standards.

The energy of the displaced gas returned from the ship during the loading operation or transferred to the LNG tanker during the unloading operation from storage tank can be determined by the following expression at the reference conditions of 15 °C and 1.01325 bar (British Petrol and International Gas Union, 2011; International Group of Liquefied Natural Gas Importers, 2011):

$$E_{GD} = V_{LNG} \cdot \frac{273.15}{273.15 - T} \cdot \frac{p}{1.01325} GCV_{GAS} \tag{7}$$

where E_{GD} is energy of the gas displaced from the LNG tank in J, V_{LNG} volume of the LNG loaded or unloaded in m^3, p absolute pressure in the tanks in bar, T mean value of the temperatures of the probes not immersed in LNG in °C, GCV_{GAS} gross caloric value of the gas in gaseous state contained in the ship's tanks in J/m^3.

Since the composition of the vapour returned is not the same as that of the LNG delivered from the ship, it is common practice to assume the return gas to be 100% methane in the calculation of the energy of the gas displaced.

The quantity of gas possibly used by the LNG tanker as fuel during loading or unloading operations can be determined by:

$$E_{GE} = V_G \cdot GCV_{GAS} \tag{8}$$

where E_{GE} is the energy of the gas used by the LNG tanker (engine room) in J, V_G the total volume of gas determined by a gas flow meter on board the LNG tanker in m^3.

During loading operations, E_{GE} has positive sign while for unloading operation has negative sign.

According to the IS06976 standard, GCV_{GAS} is calculated with the following formula (International Group of Liquefied Natural Gas Importers, 2011):

$$GCV_{GAS} = \frac{\sum_{1}^{n} y_i \cdot GCV_i}{\sum_{1}^{n} y_i \cdot MV_i} \tag{9}$$

where GCV_{GAS} is the volumetric gross calorific value of the displaced gas in J/m^3, y_i molar fraction of component *i* in the displaced gas mol/mol, GCV_i molar gross calorific value of component *i* in J/mol and MV_i molar volume of component *i* in m^3.

The molar composition of the displaced gas differs from the composition of LNG and is determined either by the analysis of gas, or by calculation.

The molar composition calculation is possible with a general formula for Vapour-Liquid-Equilibria (VLE) calculation based on equilibrium ratio (Riazi, 2005; International Group of Liquefied Natural Gas Importers, 2011):

$$K_i = \frac{x_i}{y_i} \tag{10}$$

where K_i is the dimensionless equilibrium ratio, x_i molar fraction of component *i* in liquid in mol/mol, y_i molar fraction of component *i* in the displaced gas in mol/mol.

The dimensionless equilibrium ratio K_i generally varies with *T, p* and composition of both liquid and vapour phases. Assuming the ideal solution for hydrocarbons, K_i value at various temperatures and pressures has been calculated for n-paraffins from C1 to C10 and is presented graphically for quick estimation. For hydrocarbon systems and reservoir fluids, there are also some empirical correlations for the calculation of K_i values, such as the correlation proposed by Hoffman which is widely used in the industry (Riazi, 2005). For practical calculation of the displaced gas, K_i values are usually limited to the more volatile components, i.e. nitrogen, methane and sometimes ethane.

The energy of the gas consumed as fuel in the engine room during the loading or unloading operations of an LNG tanker with cargo capacity of 145 000 m^3 and a steam turbine propulsion system, typically equals 0.05 -0.06% of the total energy of the transferred LNG (International Group of Liquefied Natural Gas Importers, 2011).

5. CONCLUSION

One of the problems in LNG transportation and storage is the generation of BOG. These vapours are created due to the heat added into the LNG during storage, transportation and loading/unloading operations.

This paper shows the causes of generation and general methods of handling and utilization of BOG at different places of the LNG supply chain.

In the LNG supply chain most BOG is generated by the LNG ships themselves. The used LNG cargo or losses of LNG cargo due to boil-off reduce the amount of cargo delivered by LNG tankers to the receiving terminal while the ageing process steadily changes the composition, quality and properties of LNG cargo during a ship's voyage. Therefore, the quantity and quality of unloaded LNG are the key factors for the economic assessment of the LNG supply chain. Consequently, this paper also describes the mathematical method for the determination and calculation of the LNG energy quantity unloaded from the ship's tanks to storage tanks in the receiving terminal. Future research will focus on simulating and computing boil-off in all parts of the LNG supply chain.

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Attachment R-3

Modelling of Boil-Off Gas in LNG Tanks: A Case Study

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Modelling of Boil-Off Gas in LNG Tanks: A Case Study

Ebenezer Adom, Sheikh Zahidul Islam and Xianda Ji
School Engineering, Robert Gordon University, Aberdeen, United Kingdom
E-mail of corresponding author: e.adom@rgu.ac.uk

***Abstract*— This paper focuses on the effect of pressure and heat leakages on Boil-off Gas (BOG) in Liquefied Natural Gas (LNG) tanks. The Lee-Kesler-Plocker (LKP) and the Starling modified Benedict-Webb-Rubin (BWRS) empirical models were used to simulate the compressibility factor, enthalpy and hence heat leakage at various pressures to determine the factors that affect the BOG in typical LNG tanks of different capacities. Using a case study data the heat leakage of 140,000kl, 160,00kl, 180,000kl and 200,000kl LNG tanks were analyzed using the LKP and BWRS models. The heat leakage of LNG tanks depends on the structure of tanks, and the small tanks lose heat to the environment due to their large surface area to volume ratio. As the operation pressure was dropped to 200mbar, all four of the LNG tanks' BOG levels reached 0.05vol%/day. In order to satisfy the BOG design requirement, the operating pressure of the four large LNG tanks in the case study was maintained above 200mbar. Thus, the operating pressure impacts BOG on LNG tanks, but this effect is limited under the extreme high operation pressure. An attempt was made to determine the relationship between the compositions of LNG and BOG; one been combustible and the other non-combustible gases. The main component of combustible gas was methane, and nitrogen was of non-combustible gases. The relationship between BOG and methane compositions was that, as the methane fraction increases in the LNG, the BOG volume also increases. In general, results showed a direct correlation between BOG and operating pressure. The study also found that larger LNG tanks have less BOG; however as the operation pressure is increased the differences in the quantity of BOG among the four tanks decreased.**

Keywords: Boil-off Gas (BOG), Liquefied Natural Gas (LNG), Lee-Kesler-Plocker (LKP) and Starling modified Benedict-Webb-Rubin (BWRS) model.

1. INTRODUCTION

Natural gas is favored, in many countries, over other fuels such as coal because of its relatively high quality and cleaner burning character which thus reduces pollution to the environment. Liquefied natural gas (LNG) is a better form for the long distance transportation and storage of natural gas. LNG is produced by cooling natural gas with liquid nitrogen to -160^{o}C under the normal pressure. The resultant volume of the LNG will be 1/600 that of the original natural gas. Thus, LNG is the format for natural gas transportation and storage. The LNG industry and trade increased rapidly in recent years. The common characteristic of LNG Storage tanks is the ability to store LNG at the very low temperature of -160^{o}C. LNG storage tanks have double containers, where the inner contains LNG and the outer container contains insulation materials. [1, 2]
Boil-Off Gas (BOG) is the vapour phase in the LNG tanks. As the increase in BOG will leads to an increase in the pressure of the LNG tank as the volume of the gas form is much greater than the liquid form, BOG can be a big problem for LNG tanks storage.

In this study, the heat leakage of LNG tanks would be investigated, because it is the main reason for BOG of LNG tanks. As the heat leakage is determined by the structure of the tanks, the different types of LNG tank should be learned, firstly.

Some parameters also can impact BOG quantity, such as operating pressure, and compositions of LNG. Thus, the thermodynamics character of LNG needed to analysis, it is necessary to choose a suitable model to apply, and to process available computer programs, in order to compute these models. The results of each model are discussed and the general character of BOG would be obtained; thus, some useful suggestions could be given for the use of LNG tanks.

2. LNG MODELS

There are many kinds of model available for LNG modelling, which range from the simplest Gaussian model, through simplified density gas models to computational fluid dynamic codes [3]. The Gaussian model assumes dispersion is dominated by atmospheric turbulence and ignores dense gas effects thus is not considered appropriate for gas density equation. There are several current uses of CFD codes for LNG [4], as CFD directly uses the fundamental equations of fluid flow. Also local geographic feature can be included in CFD by working with a customized grid and boundary conditions. However, the disadvantage of CFD is that there are many additional modeling issues which should be addressed. Thus, CFD code has not been a routine model for LNG.

Equations of state (EOS) are commonly used to analyze the vapor-liquid phases of multi-component fluid mixtures. The Lee-Kesler-Plocker (LKP) equation draws upon the relationship of PVT (Pressure, Volume, and Temperature). It was first proposed for in use for thermodynamic properties by Ploker [5]. The LKP equation is an accurate general method for non-polar substances and mixtures, which can be used in the calculation of density and enthalpy.

In order to calculate the BOG of LNG, the density, and enthalpy are the key parameters, and virial equations are just theoretical expressions, they are developed by LKP model and BWRS model; thus, LKP and BWRS model are suitable methods to compute BOG of LNG. Furthermore, the two models are convenient for computer programming. LKP models are used for calculating the compressibility factor and deriving thermodynamic properties of normal fluids and modified LKP equations for calculation of polar fluids. An acentric factor as the fourth parameter was added to calculate vapor-phase data for each fluid. The accuracy of some equations of state for the prediction of molar volume for different hydrocarbons were reviewed by Ye *et al*. [6] and Solimando *et al.* [7], recently. Ye used the corresponding states LKP model, Peng-Robinson model, and Simonet-Behar-Rauzy equation. He concluded the LKP model to generally produce better results, especially at high pressures.

Solimando analyzed three equations (Simonet-Behar-Rauzy, Lee-Kesler-Prausnits, and Chain of Rotators equations), which are based on more theoretical developments. They concluded that the LKP model had more accurate densities for light hydrocarbons. Using the LKP model only the critical pressure, temperature and ancentric factor are the required input parameter needed to calculate the density and enthalpy of LNG. However, the LKP model does not consider the effect of components of LNG.

2.1 LKP model

According to Robert [6], the LKP equation is given as:

$$Z = Z^{(0)} + \frac{\omega}{\omega^{(r)}}(Z^{(r)} - Z^{(0)}) \tag{1}$$

$$\omega = -\log_{10}(\frac{p}{p_c}) - 1 \quad \text{at} \quad \frac{T}{T_c} = 0.7 \tag{2}$$

Z is compressibility factor, which is obtained using the gas law,

$$Z = \frac{PV}{nRT} \tag{3}$$

Through to improve the factor $z^{(r)}$, and $z^{(0)}$, equation (1) can be written as:

$$Z=(\frac{p_r v_r}{T_r})=1+\frac{B}{v_r}+\frac{C}{v_r^2}+\frac{D}{v_r^5}+\frac{c_4}{T^3 v_r^2}(\beta+\frac{\gamma}{v_r^2})\exp(-\frac{\gamma}{v_r^2}) \tag{4}$$

Where P_r is pressure contract, T_r is temperature contract, is specific heat capacity contract. And *B*, *C*, *D*, C_4, β and γ are the parameter, which could be obtained from table [8].

Assuming in the LNG tank the whole process is isothermal, and the different in enthalpy and entropy is only depended on the initial and final state. Thus, according to LKP equation, the change in enthalpy would be:

$$\frac{\Delta H}{RT_r} = (\frac{\Delta H}{RT_r})^{(0)} + \frac{\omega}{\omega^{(r)}}[(\frac{\Delta H}{RT_r}) - (\frac{\Delta H}{RT_r})^{(0)}] \tag{5}$$

Using equation (3), the density of the true liquid is obtained as:

$$\rho_t = \frac{1}{v_t} = \frac{p_t}{ZRT_t} \tag{6}$$

Thus substitute equation (6) into (4), the function of ρ_t should be:

$$\begin{aligned} f(\rho_r) = T_r\{\rho_r + B\rho_r^2 + C\rho_r^3 + D\rho_r^6(\beta + \gamma\rho_r^2) \\ \exp(-\gamma\rho_r^2)\} - p_r \end{aligned} \tag{7}$$

To derivate the function:

$$\begin{aligned} f'(\rho_r) = T_r\{1 + 2B\rho_r + 3C\rho_r^2 + 6D\rho_r^5 + \\ \frac{c_4}{T_r^3}\rho_r^2[3\beta + \gamma\rho_r^2(5 - 2\beta) - 2\gamma^2\rho_r^4\exp(-\gamma\rho_r^2)\} \end{aligned} \tag{8}$$

Thus,through the Newton-Raphson iterative formula, the data processing was computed.

2.2 BWRS model

The Benedict-Webb-Rubin equation (BWR) is an equation of state used in fluid dynamics, the original model states as [20]:

$$\begin{aligned} P = \rho RT + (B_0RT - A_0 - \frac{C_0}{T^2})\rho^2 + (bRT - a)\rho^3 \\ + \alpha a\rho^6 + \frac{c\rho^3}{T^2}(1 + \gamma\rho^2)\exp(-\gamma\rho^2) \end{aligned} \tag{9}$$

And there is a modification of BWR by Kenneth Starling [9], as:

$$\begin{aligned} P = \rho RT + (B_0RT - A_0 - \frac{C_0}{T^2} + \frac{D_0}{T^3} - \frac{E_0}{T^4})\rho^2 + (bRT - a - \frac{d}{T})\rho^3 \\ + \alpha(a + \frac{d}{T})\rho^6 + \frac{c\rho^3}{T^2}(1 + \gamma\rho^2)\exp(-\gamma\rho^2) \end{aligned} \tag{10}$$

which is BWRS model. ρ is molar density; T is the temperature; and P is the pressure.

In order to calculate [17], it is necessary to assume:

$R_1 = RT$; $R_2 = B_0RT - A_0 - \frac{C_0}{T^2} + \frac{D_0}{T^3} - \frac{E_0}{T^4}$; $R_3 = bRT - a - \frac{d}{T}$; $R_4 = \alpha(a + \frac{d}{T})$; and $R_5 = \frac{c}{T^2}$.

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Thus, the BWRS equation can be written as:

$$P = R_1\rho + R_2\rho^2 + R_3\rho^3 + R_4\rho^6 + R_5\rho^3(1+\gamma\rho^2)\exp(-\gamma\rho^2) \tag{11}$$

It also can be changed to an equivalent equation, which can be iterated.

$$\rho = \left\{\left[P - R_1\rho - R_3\rho^3 - R_4\rho^6 - R_5\rho^3\left(1+\gamma\rho^2\right)/R_2\right]\right\}^{1/2} \tag{12}$$

This equation can be convergence to one direction, thus, to make $f(\rho) = 0$

2.3 Data of LNG Heat Leakage

The temperature of LNG is about -160°C, so heat energy is transferred through the thermal insulation layer into the LNG tanks. This heat transfer causes the LNG to evaporation. It is also the reason for the pressure change in the LNG tank. As the heat leakage is the energy exchange between the inner tank and outside environment, it can be controlled to a certain extent by the structure of LNG tank. [1,2,10,11]

Three assumptions were made for computing the heat leakage of LNG tanks which are as follows:

- All the evaporation of LNG only occurs at the surface of the liquid phase;
- During the process of evaporation, the vapour-liquid phases are equilibrium;
- The temperature and density of LNG is constant during the whole process.

The heat leakage of LNG tanks was calculated by each part: Roof, Side, and Bottom [12]. Table 1 shows the heat leakage results of four kinds of LNG tanks.[13,14]

TABLE 1:
HEAT LEAKAGE OF FOUR TANKS

	140,000 kl	160,000 kl	180,000 kl	200,000 kl
Roof, W	40352	37334 (without deck)	46609	45396
Side, W	51694	53935	49333	49866
Bottom, W	77872	71984	70610	68000
Total, W	169919	168243	166552	163253

2.4 Boil-off Gas of LNG Tank

LNG is stored in vessels with cryogenic tanks in the absence of any means of external refrigeration; thus, there is a little BOG, which means a little volume evaporates. The BOG of LNG has been a key issue for economic and technical reasons. BOG causes the pressure to increase inside the inner LNG tank, which also produces a safety risk. The assessment of the BOG quantity and thermodynamic properties during storage in the tank is of key importance to the whole LNG transport system. The heat leakage leads to the BOG of the tank. [15, 16]

The boil of gas (BOG) is computed using equation

$$BOG = \frac{m \times 3600 \times 24}{V\rho} \tag{13}$$

The rate of gas evaporation could be obtained as:

$$m = \frac{\phi}{\Delta h} \tag{14}$$

Figure1 and Figure 2 show the results of LKP model and BWRS models.

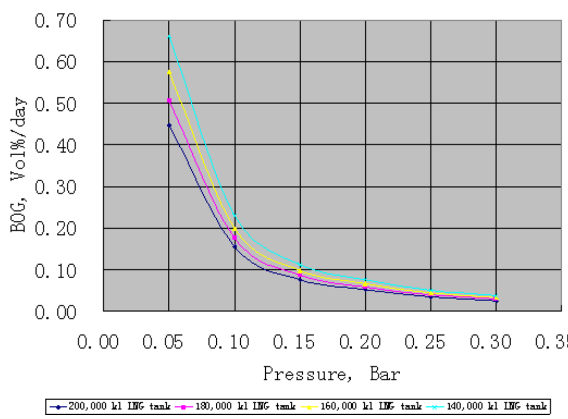

Fig.1: The relationship between operating pressure and BOG

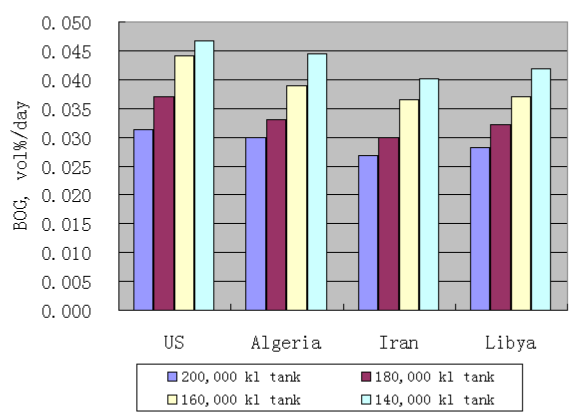

Fig.2: BOG of different sources of LNG [18]

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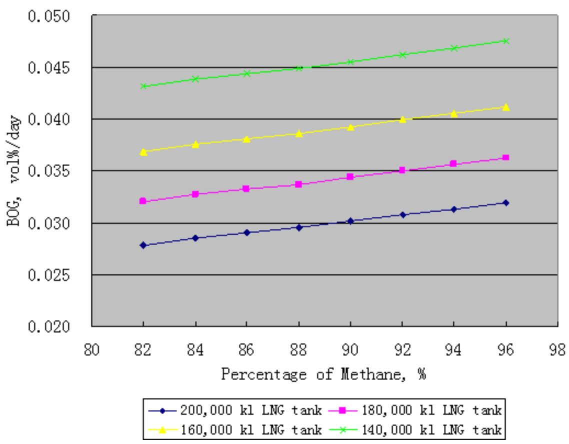

Fig.3: Relationship between BOG and percentage of Methane

The heat leakage of LNG tanks depends on the structure of tanks, and the small tanks lose heat to the environment due to their large surface area to volume ratio.

There are several types of LNG tanks that have the different insulation systems; as such the thermal conductivity of LNG tanks is dependent on the insulation system of the tank in addition to its size. Using case study data the heat leakage of 140,000 kl, 160,000 kl, 180,000 kl and 200,000 kl LNG tanks were calculated to be 169,919 W, 168,243 W, 166,552 W and 163,253 W, respectively.

According to Prasad *et al.* [11], the BOG of normal large LNG tank is about 0.03~0.08 vol%/day, thus, there could be about 60~160 kl of liquid gas evaporating every day from a 200,000 kl LNG tank. The vapour can lead to the pressure of LNG tank increasing; on the other hand, it is useful to know the BOG volume of LNG tank through pressure monitoring.

In the case study, the design pressure of large LNG tanks are between 50~350 mbar [13], and the design BOG is 0.05 vol%/day. However, results using LKP model showed that the BOG levels increase as the operation pressure decreases (Fig.1). When the operation pressure was dropped to 200mbar, all four of the LNG tanks' BOG levels reached 0.05 vol %/day. So, in order to satisfy the BOG design requirement, the operating pressure of the four large LNG tanks in the case study must be maintained above 200 mbar.

3. CONCLUSION

The heat leakage should be the key requirement for BOG in LNG tank; and the size can impact the thermal conductivity of the LNG tank, except the insulation system. The heat leakage of a tank during storage has been analyzed. For different types of tanks, heat transmission through tank roof, sides and bottom has been defined and described in general formula.

The operating pressure and compositions of LNG can impact BOG during storage. As the temperature and volume of LNG tank are constant, the operating pressure can be a monitor for BOG. It analyzed the results from LKP model, the relationship between operating pressure and BOG can be obtained, as Fig.1 shown. These curves can be the reference for LNG tank operating to control the BOG. In addition, the different source of LNG also should be considered during the storage, the results from BWRS model gave the reference for the relationship between compositions of LNG and BOG.

It is necessary to simulate the whole process of the BOG in LNG tanks. The simulation needs be consider the dynamic process of vapour space of the LNG tanks. There are also some other parameters, which can impact BOG, needed to add into the simulation; such as, the changing of environment temperature, and the time for LNG storage.

It is better to find a suitable method to deal with the BOG. There are several ways to manage the BOG, such as re-liquefaction, or torching the BOG [19]. Torching is a easy way to deal with BOG, but it would waste LNG; re-liquefaction can recycle the BOG as LNG, however, the operating costs of re-liquefaction system is expansive. Thus, it is necessary to built a model for choosing the method to manage the BOG of LNG tanks.

NOMENCALTURE

A: Area (m^2)
B, C, D: Parameters of equation of state
Δh: Enthalpy difference (kJ/kg)
h: Heat transfer coefficient(W/(m^2/K))
m: the quantity rate for boil-off gas of tank (kg/s)
n: Number of moles of a substance
P: Pressure (bar)
R: Universal gas constant
r: Thermal resistant(W/(m·K))
T: Temperature (K)
V: Volume (kl)
X: Angle factor between the roof and suspended deck (degree)
Y: Each component of LNG (%)
Z: Compressibility factor
Greek symbols
ρ : Density (kg/m^3)
ω: Acentric facto (Dimensionless)
Φ : Heat leakage of tank (W)
δ : Thickness of insulation layer (mm)
λ : Thermal conductivity of insulation layer (W/(m K))
ε : Emissivity (Dimensionless)
σ : Blackbody radiation constant (W/m^2K^4)

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AUTHORS PROFILE

Dr. Eben Adom is currently a Lecturer in Mechanical Engineering at the Robert Gordon University, Aberdeen. He received his PhD from Heriot-Watt University, Edinburgh in boiling heat transfer in 2007. His current research interest includes the boiling heat transfer, heat pipes, heat exchangers, multiphase flow and thermal systems .

Sheikh Zahidul Islam is a research / teaching assistant at Robert Gordon University, Aberdeen. He received his M.S. degree from the Department of Mechanical Engineering at Kongju National University, Gongju, Korea, in 2005. His areas of interest are heat transfer in fluidized bed/multiphase flow, fouling of heat exchangers, computational fluid dynamics and fuel cell.

Xianda Ji completed his M.Sc. in oil and gas engineering from Robert Gordon University, Aberdeen in 2009. This paper is outcome of his M.Sc. thesis.

Attachment S

Confidentiality Declaration

BEFORE THE PUBLIC UTILITIES
COMMISSION OF THE STATE OF CALIFORNIA

DECLARATION OF DOUGLAS M. SCHNEIDER
REGARDING CONFIDENTIALITY OF CERTAIN DATA/DOCUMENTS
PURSUANT TO D.16-08-024

I, Douglas M. Schneider, do declare as follows:

1. I am the Vice President of System Integrity and Asset Management for San Diego Gas & Electric Company ("SDG&E") and Southern California Gas Company ("SoCalGas"). I have reviewed the confidential attachments to the Rebuttal Testimony of SDG&E and SoCalGas, submitted concurrently herewith ("Confidential Attachments to Rebuttal Testimony"). I am personally familiar with the facts and representations in this Declaration and, if called upon to testify, I could and would testify to the following based upon my personal knowledge and/or belief.

2. I hereby provide this Declaration in accordance with Decision ("D.") 16-08-024 to demonstrate that the confidential information ("Protected Information") provided in the Confidential Attachments to Rebuttal Testimony are within the scope of data protected as confidential under applicable law, and pursuant to California Public Utilities Code ("P.U. Code") § 583 and General Order ("GO") 66-C, as described in Appendix A hereto.

3. In accordance with the legal authority described herein, the Protected Information should be protected from public disclosure.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge.

Executed this 12th day of June, 2017, at Los Angeles, California.

Douglas M. Schneider

Douglas M. Schneider
Vice President - System Integrity
and Asset Management
San Diego Gas & Electric and
Southern California Gas Company

APPENDIX A

SDG&E and SoCalGas Request for Confidentiality on the following Protected Information in the Confidential Attachments to Rebuttal Testimony

Location of Data	Description of Data	Applicable Confidentiality Provisions	Basis for Confidentiality
"Confidential Attachments to Applicants' Rebuttal Testimony.pdf" And the following attachments referenced therein: *Attachment A-C* *Attachment B.1-C** *Attachment B.2-C* *Attachment B.3-C* *Attachment B.4-C†* *Attachment B.5-C** *Attachment B.9-C** **Confidential declarations were previously provided for these submissions.* *† A confidential declaration was provided as part of the submission for the amended response included in this attachment.*	The Confidential Attachments to Applicants' Rebuttal Testimony provides: Attachment A-C: *Columns B & C- Pipeline Stationing; E – Design Factor; H – Wall Thickness; I- Specified Minimum Yield Strength (SMYS); J- Installation Date; L - % SMYS at 640 psig; M - % SMYS at 320 psig* Attachment B.2-C (ORA 19, Q6 and attached response to SED 3, Q2 Attachment): Columns labeled as- *BEGENGSTA; ENDENGSTA; DOTCLASS; DESIGN FACTOR; WT; SMYS; INSTALLDATE; TESTPRESSURE TESTDATE; GRANDFATHERPRESSURE; %SMYS; 192619 (A1); 192619 (A2); 192619 (A3); MAOP_192619_GOV CASE* Attachment B.3-C	The Pipeline and Hazardous Materials Safety Administration ("PHMSA") guidelines in the Federal Register, Vol 81, pg. 40764, published on 6/22/2016 and U.S. Department of Homeland Security Transportation Security Administration ("TSA") guidelines consider the data to be restricted pipeline information. Critical Energy Infrastructure Information ("CEII") under 18 CFR § 388.113(c); Federal Energy Regulatory Commission ("FERC") Orders 630, 643, 649, 662,683, and 702 (defining CEII). Critical Infrastructure Information ("CII") under 6 U.S.C. §§ 131(3), 133(a)(1)(E); 6 CFR §§ 29.2(b), 29.8 (defining CII and restricting its disclosure). Cal. Gov't Code § 6254(e) exempts from mandatory disclosure, plant production data, and similar information relating to utility systems. Pressure information is also exempt from public disclosure per Cal. Gov't Code § 6254(e).	"Wall Thickness" and "Yield Strength" are specific engineering design information about an existing critical infrastructure that could be used to determine the criticality of a gas facility and identify vulnerabilities of the gas delivery network. The values can be used to calculate stress levels of a pipe. Because of the critical nature of these attributes, they have been identified by PHMSA to be restricted attributes available only to government officials in the Federal Register Vol. 81, pg. 40764 published in 6/22/2016. "Pipe Diameter" is a specific engineering design value depicting an attribute of a proposed or existing critical infrastructure that could be used to determine the criticality of a gas facility and identify vulnerabilities of the gas delivery network. The value can be used to identify the volume of gas present in an area and ascertain the relative potential consequences of intentional acts against the gas transportation and distribution network. Because of the critical nature of the attribute, it has been identified by PHMSA to be a restricted pipeline attribute in the Federal Register Vol 81, pg. 40764 published on 6/22/2016. Diameter is also exempt from public disclosure per the CEII and CII regulations for the same security reasons. Operating "pressure" (i.e., MAOP) is a specific engineering design value as well as an operating parameter depicting an attribute of an existing critical infrastructure. This operating parameter could be used to determine the criticality of

	(SED 3, Q2 Attachment): *Same columns as referenced for Attachment B.2-C* Attachment B.4-C (Response to ORA-25, Q1 Attachment dated August 12, 2016): *Columns labeled as- BEGENGSTA; ENDENGSTA; DOTCLASS; DESIGN FACTOR; WT; SMYS; INSTALLDATE; TESTPRESSURE TESTDATE; GRANDFATHERPRESSURE; %SMYS; 192619 (A1); 192619 (A2); 192619 (A3); MAOP_192619_GOVCASE; Joint Factor*		a gas pipe or facility and identify vulnerabilities of the gas delivery network. The release of this operating parameter is detrimental to public safety as it can be used as a means to identify the volume of gas present and potential energy that could be released in an area in order to identify the potential consequences of an intentional act of sabotage. Because of the critical nature of the parameter, it has been identified by PHMSA to be restricted pipeline information as well being an SSI element in the Federal Register Vol 81, pg. 40764 published on 6/22/2016. Pressure information is also exempt from public disclosure per the CEII and CII regulations for the same security reasons