Application of San Diego Gas & Electric Company (U 902 E) for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design.

Application: 19-03-002
Exhibit No.: ________

PREPARED SUPPLEMENTAL TESTIMONY OF

JOSE L. LOPEZ, WILLIAM G. SAXE, BENJAMIN A. MONTOYA AND TALAL H. HANNA

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MAY 2019

SDGE

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PREPARED SUPPLEMENTAL TESTIMONY OF
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TALAL H. HANNA

I. OVERVIEW AND PURPOSE

The purpose of this supplemental testimony is to present San Diego Gas & Electric Company's ("SDG&E") demand charge research studies for distribution, generation, and transmission. These studies are being submitted at the direction of California Public Utilities Commission ("CPUC" or "Commission") Decision ("D.") 17-08-030, issued August 24, 2017, and Resolution E-4951, issued September 14, 2018.

The demand charge research studies are set forth in the following attachments:

- Attachment A - Distribution demand charge study results, sponsored by Jose L. Lopez and William G. Saxe.
- Attachment B - Generation demand charge study results, sponsored by Benjamin A. Montoya.
- Attachment C - Transmission demand charge study results, sponsored by Talal H. Hanna.

II. BACKGROUND

Ordering Paragraphs 33 through 35 of D.17-08-030 required SDG&E to conduct three demand charge studies: one for distribution, one for generation and one for transmission. Resolution E-4951 provided additional guidance on these studies, including the timing and procedural vehicle by which these studies would be submitted to the Commission.

Ordering Paragraph 1 of Resolution E-4951 stated that "SDG&E shall modify the studies presented in AL ["Advice Letter"] 3166-E and file them as supplemental testimony in its GRC Phase 2 proceeding within 60 days of filing its Application." SDG&E filed its 2019 GRC Phase

2 application on March 4, 2019; as such, this supplemental testimony is being timely submitted "within 60 of filing its Application."

As an additional requirement imposed on the transmission demand charge study, Ordering Paragraph 4 of Resolution E-4951 required SDG&E to present both its preferred transmission demand charge study and an alternate transmission study. Pursuant to Ordering Paragraph 34 of D.17-08-030, SDG&E filed its transmission study with the Federal Energy Regulatory Commission ("FERC") on March 4, 2019.

Pursuant to Ordering Paragraph 5 of Resolution E-4951, SDG&E will hold a publicly-noticed workshop within 30 days of submitting this supplemental testimony to discuss the results of its demand charge studies.

III. STUDY DESCRIPTIONS

A. Distribution Demand Charge Study (Attachment A)

This study is presented to describe SDG&E's examination of the allocation of distribution costs between non-coincident demand charges and system peak demand charges. The Commission also directed certain modifications and additional data to serve as the basis for a parallel study that includes use of equal percentage of marginal cost ("EPMC") for distribution and directed SDG&E to ensure the information presented in its GRC Phase 2 testimony is consistent, or explain the justified differences, with the Grid Needs Assessment ("GNA"), reflecting future distribution grid needs, and the Distribution Deferral Opportunity Report ("DDOR"), reflecting which grid needs are potentially deferrable by distributed energy resources ("DER"). Both the GNA and the DDOR reside within the Distribution Resources Planning proceeding (Rulemaking ("R.") 14-08-013). Witness Lopez discusses the allocation of costs and the relationship between the GNA and DDOR. Witness Saxe discusses the basis for a parallel study that includes the use of EPMC for distribution.

B. Generation Demand Charge Study (Attachment B)

This study is presented to describe SDG&E's examination of the appropriate allocation of generation capacity costs between volumetric and peak demand charges and whether a shorter duration peak demand period for assessing coincident peak-related demand charges should be established relative to the adopted time-of-use period. Specifically, Witness Montoya addressees:

1) Generation capacity cost allocation using the Loss of Load Expectation ("LOLE") Methodology;

2) Incorporation of ramping and renewable integration; and

3) A Shorter duration peak demand period for assessing peak-related demand charges.

C. Transmission Demand Charge Study (Attachment C)

This study is presented to describe SDG&E's examination of the allocation of costs between non-coincident and system peak demand charges relating to transmission costs. As directed by the Commission, SDG&E conducted a study to examine the appropriate allocation of transmission costs between non-coincident demand charges and system peak demand charges, as well as the system peaks and relationship to customer class demand. The research plan aimed to determine the percentage of transmission costs driven by capacity or peak needs, using transmission project costs from the most recently filed transmission rate case.

This concludes our prepared supplemental testimony.

IV. WITNESS QUALIFICATIONS

A. Witness Qualifications of Jose L. Lopez

My name is Jose L. Lopez. My business address is 8326 Century Park Court, San Diego, California, 92123. I am employed by SDG&E as Manager, Electric Distribution Planning. I have been employed by SDG&E since 2002. While at SDG&E, I have held various staff and management positions of increasing responsibility in the electric transmission and distribution operations and engineering groups. I earned a Bachelor of Science degree in Electrical Engineering from California Polytechnic San Luis Obispo. I am also a registered Professional Engineer in the state of California in the field of Electrical Engineering.

I have previously testified before this Commission.

B. Witness Qualifications of Talal H. Hanna

My name is Talal H. Hanna. My business address is 8326 Century Park Court, San Diego, California, 92123. I have been employed as a Senior Engineer in the Generation Interconnection & Transmission planning group of SDG&E since 2017. Prior to that, I was employed by Southern California Edison Company for seven years in positions of increasing responsibility in the following departments: Distribution Planning, Generation Interconnection, and Technical Studies & Tariff Support. I received a Bachelor of Science in Electrical Engineering from San Diego State University. I am also a licensed professional Electrical Engineer in the state of California.

I have never testified before this Commission.

Attachment A

Distribution Demand Charge Study Results

SDG&E Demand Charge Research Study – Distribution

Introduction

This study is presented to describe San Diego Gas and Electric Company's ("SDG&E") examination of the allocation of distribution costs between non-coincident demand charges and system peak demand charges. Non-coincident demand represents a customer's maximum demand without regard to when the demand occurred whereas system peak demand (also referred to as "on-peak demand") represents a customer's maximum demand during SDG&E's on-peak period, which, as adopted in Decision ("D.") 17-08-030, is 4 p.m. – 9 p.m. every day of the year for SDG&E's standard, non-grandfathered Time-of-Use ("TOU") periods.

As directed by the California Public Utilities Commission ("CPUC" or "Commission"), this study examines the appropriate allocation of distribution costs driven by on-peak capacity needs, and examines demands by the customer class, circuit, and substation.

The Commission also directed certain modifications and additional data to serve as the basis for a parallel study that includes use of equal percentage of marginal cost ("EPMC") for distribution and directed SDG&E to ensure the information presented in its GRC Phase 2 testimony is consistent, or explain the justified differences, with the Grid Needs Assessment ("GNA"), reflecting future distribution grid needs, and the Distribution Deferral Opportunity Report ("DDOR"), reflecting which grid needs are potentially deferrable by distributed energy resources ("DER").

More specifically, SDG&E's 2016 General Rate Case ("GRC") Phase 2, D.17-08-030, the CPUC directed SDG&E to:

"[C]onduct a study to examine the appropriate allocation of distribution costs between noncoincident demand charges and system peak demand charges to be included in the next San Diego Gas & Electric Company Phase 2 General Rate Case. San Diego Gas & Electric Company must consult with parties to this proceeding in preparing its research plan for the study, and file the research plan as a Tier 2 Advice Letter within 120 days of the effective date of this decision."[1]

SDG&E solicited feedback from various parties in development of its research plan, including:

- Receiving written feedback during initial study scope development;
- Verbal feedback during November 1, 2017 and December 7, 2017 telephonic workshops; and
- Additional written feedback on draft scope document and the near final scope document.

[1] Ordering Paragraph 33.

SDG&E filed Advice Letter ("AL") 3166-E on December 21, 2017, which detailed the Demand Charge Research Plan. On September 13, 2018, the CPUC adopted Resolution E-4951, which approved, with modifications, SDG&E's proposed demand charge research plan, and directed SDG&E to perform parallel studies of its distribution demand charges based on certain modifications described above.

Study 1 – SDG&E's Proposed Approach

Step 1: Examine the breakdown of distribution costs to identify what percentage of distribution costs are driven by capacity.

To perform Step 1, SDG&E utilized the 2017-2019 estimated capital expenditures from the 2019 GRC Phase 1 workpapers of SDG&E Witness Colton[2] and identified capacity-driven projects. This section describes the process by which SDG&E's Distribution Planning organization develops these forecasted capital expenditures. SDG&E's forecasted costs associated with capital electric distribution work are those SDG&E deems necessary to provide safe, reliable, and high-quality service to its customers. SDG&E's capacity-driven projects provide data on distribution facility additions designed by SDG&E to meet peak demand for that portion of the distribution system which serves customers located in a specific area. Forecast methodologies for distribution planning costs, as described in SDG&E's GRC Phase 1, were selected based on future expectations for the underlying cost drivers, and include:

- Forecasts based on historical averages;
- Forecasts based on the 2016 adjusted recorded spending; and
- Forecasts based on zero-based cost estimates for specific projects.

Funding requirements for new or more extensive work elements are forecasted based on historical spending plus incremental expense requirements.

SDG&E's capital electric distribution costs are broken down into the 11 primary cost categories discussed below. SDG&E has presented these cost categories as either: 1) those identified as being driven by capacity needs; and 2) those not identified as being driven by capacity needs.

Cost categories identified as being driven by capacity needs:

- *Capacity/Expansion*: capacity projects needed to correct equipment loadings above 100%, due to an area load growth, or those projects required to increase system capacity where highly loaded equipment (above 90%) will adversely impact operations and reliability.

Cost categories not identified as being driven by capacity needs:

- *Equipment/Tools/Miscellaneous*: purchase of new electric distribution tools and equipment required by field personnel to safely and efficiently inspect, operate and maintain the electric distribution system.

[2] A.17-10-007, Exhibit SDG&E-14-R, Revised Direct Testimony of Alan F. Colton – Electric Distribution – Capital (December 2017) ("Ex. SDG&E-14-R/Ex. 74 (Colton Direct)").

- *Franchise*: projects required to perform municipal overhead to underground conversion work or work in accordance with SDG&E's franchise agreements. The two categories of projects in this category are: 1) those devoted to conversion of overhead distribution systems to underground; and 2) street or highway relocations due to improvements by governmental agencies.
- *Mandated/Compliance*: Projects required in compliance with programs mandated by the CPUC or other regulatory agencies.
- *Materials*: expenditures required to provide distribution transformers necessary to operate and maintain the electric distribution system.
- *New Business*: Connection of new residential and non-residential customers, which includes new services, upgraded services, new distribution systems for commercial and residential developments, system modifications to accommodate new customer load, customer requested relocations, rearrangements, removals, and the conversion of existing overhead lines to underground.
- *Overhead Pools*: Expenditures for project direct labor, contracted invoice amounts, or total project direct costs for engineering capacity studies, reliability analysis, preliminary design work, and other expenditures that cannot be attributed to a single capital project and are thus spread to those applicable projects that are ultimately constructed and placed into service.
- *Reliability/Improvements*: Proactive infrastructure replacement projects in avoidance of reactive repair or replacements, projects required to maintain or improve reliability, and projects that are associated with risk and mitigation efforts.
- *Safety & Risk Management*: Capital investments made to address the mitigation of safety and physical system security risks, including expenditures to reduce wildfire risk.
- *Distributed Energy Resource Integration*: Investments needed to change the distribution grid from its original design of point-source one-way power flows to a grid that can accommodate multi-point two-way power flows, as well as investments to develop the instrumentation, troubleshooting, and safety procedures necessary to the modern DER-enabled grid.
- *Transmission/Federal Energy Regulatory Commission ("FERC") Driven Projects*: Investments made in transmission projects with a distribution component to modify or replace distribution facilities in conjunction with the transmission work to accommodate the new project.

SDG&E's 2017-2019 forecast is developed by analyzing historical 2011-2016 actual expenditures and the underlying cost drivers behind the expenditures to develop an assessment of future requirements. Capacity/Expansion projects typically consist of load transfers, re-conductors, circuit extensions, new circuits, and substations to mitigate the capacity deficiency. SDG&E must construct the distribution system to accommodate the peak load in order to safely and reliably meet all capacity needs. Actual capacity expenditures are linked to customer and load growth, but are not always proportional, and locational variations will exist with respect to available capacity. To develop its forecast for capacity/expansion projects, SDG&E utilized customer growth forecasts, new customer requests, forecasted demand, and distribution substation assessments, which collectively generate the best estimates of future capital requirements for capacity. SDG&E forecasts project loads on each circuit and substation within the system and evaluates these load forecasts against system capabilities to determine whether system modifications are required.

Of the total 2017-2019 forecasted expenditures, 2.8% of SDG&E's distribution capital projects are driven by capacity needs, as presented in Table 1. The numbers presented here are in summary form from Table 2 below.

Table 1: SDG&E Forecasted Distribution Capital Expenditures 2017-2019

SDG&E Electric Distribution Cost Allocation				
	Estimate 2017 ($000)	Estimate 2018 ($000)	Estimate 2019 ($000)	Estimate Total ($000)
Capacity Driven	$13,269	$11,002	$25,176	$49,447
Total Electric Distribution Capital	$445,116	$589,811	$702,749	$1,737,676
Percent Capacity Driven	3.0%	1.9%	3.6%	2.8%

Table 2 below presents a summary of all SDG&E's distribution capital expenditures by cost category.

Table 2: Capital Expenditures Summary of Costs by Category[3]

ELECTRIC DISTRIBUTION Figures Shown in 2016 Dollars						
Categories of Management	Estimated 2017 ($000)	% 2017	Estimated 2018 ($000)	% 2018	Estimated 2019 ($000)	% 2019
Capacity/Expansion	13,269	3.0%	11,002	1.9%	25,176	3.6%
Equipment/Tools/Miscellaneous	4,833	1.1%	2,531	0.4%	3,029	0.4%
Franchise	34,463	7.7%	40,180	6.8%	35,190	5.0%
Mandated	33,169	7.5%	34,377	5.8%	32,662	4.6%
Materials	24,871	5.6%	26,315	4.5%	27,694	3.9%
New Business	55,317	12.4%	57,186	9.7%	60,592	8.6%
OH Pools	85,103	19.1%	120,386	20.4%	162,491	23.1%
Reliability/Improvements	74,863	16.8%	108,418	18.4%	103,448	14.7%
Safety and Risk Management	83,747	18.8%	113,497	19.2%	184,333	26.2%
Distributed Energy Resource (DER) Int.	3,298	0.7%	18,343	3.1%	18,016	2.6%
Transmission/FERC Driven Projects	32,183	7.2%	57,576	9.8%	50,118	7.1%
Totals	**445,116**	**100.0%**	**589,811**	**100.0%**	**702,749**	**100.0%**

As displayed above, 3.6% of SDG&E's estimated 2019 forecasted electric distribution projects are classified as Capacity/Expansion.

[3] Ex. SDG&E-14-R/Ex. 74 (Colton Direct), Table AFC-4, at AFC-16.

Cost Drivers

Resolution 4951-E also required SDG&E to be cognizant of both primary and secondary cost drivers for distribution capital expenditures.[4] Finding of Fact 10 stated that distribution projects may have multiple cost drivers. While SDG&E does not disagree with this statement in theory, SDG&E's proposed capital expenditure projects are defined solely by their primary cost driver. Although there may be secondary benefits that provide capacity attributed to other projects, including reliability/improvements, safety, power quality and regulatory compliance, the main driver for the expenditure is how the project is classified as displayed in Table 2. Any secondary drivers are often negligible and difficult to measure and would not have any bearing on whether SDG&E undertakes the project.

The same principle is true for capacity/expansion-driven projects. While there may be secondary benefits/cost drivers to these capacity projects, including reliability, safety, power quality and regulatory compliance, the main driver for the capacity expenditure is to address the distribution system need to safely and reliably meet the capacity needs of SDG&E's distribution system. Therefore, the project is classified in the capacity category, as the need for capacity is the catalyst for the project.

Step 2: Examination of the demands at the relevant measurement levels (i.e. by customer class, circuit, and substation) during the currently defined on-peak TOU period and non-peak TOU periods. This examination will indicate the circuits and distribution substations whose maximum demands occurs:

1) within the currently defined on-peak TOU period, and

2) outside of the currently defined on-peak TOU period.

With this information, it is possible to calculate the percentage of circuits and substations whose peak occurs within or outside of the on-peak period. Combining the percentage of load occurring in the two categories with the percentage of capacity-driven distribution costs, will inform the appropriate allocation of distribution costs to an on-peak demand charge.

Table 3 below presents SDG&E's 2014-2016 Average Substation and Circuit Effective Demand Factor ("EDF") ratios. EDFs are the estimated ratio of the average class contribution to the peak demand at the circuit and substation level that are used in SDG&E's GRC Phase 2. EDFs are used to allocate distribution costs for circuits and substations to customer classes.

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[4] Resolution 4951-E at 9.

Table 3:
SDG&E 2014-2016 Average Substation and Circuit Effective Demand Factor Ratios

2014-2016 Average	Substation EDF Ratio	Circuit EDF Ratio
Residential	32%	35%
Small Commercial	43%	47%
M/L C&I	66%	71%
Agricultural	32%	34%
Lighting	35%	33%

Step 3: SDG&E examined the circuit and substation peak demands and their relationship to customer classes' demand coincident with the system peak period. To determine the appropriate allocation of the distribution capacity-related costs, SDG&E determined the percentage of circuits and substations that peaked during the system peak period (4-9 p.m.) and non-coincident (all hours) time frames.[5] The percentage of circuits and substations that peak during the on-peak period, and the respective magnitudes, were used to calculate the percentage of capacity-driven distribution costs that should be considered for recovery through a peak demand charge.

Charts 1 and 2 below present SDG&E's 2014-2016 circuit and substation peaks over a 24-hour period. Although a percentage of SDG&E's circuits and substations peak during the on-peak period (4 p.m. – 9 p.m.), many circuits and substations peak outside the on-peak period (all other hours).

[5] Note that SDG&E's on-peak period during this time for standard TOU was 11 a.m. – 6 p.m. SDG&E implemented new TOU periods per D.17-08-030 on December 1, 2017, which moved the standard on-peak period to 4 p.m. –
9 p.m. For purposes of this study, SDG&E's reference to "on-peak" is 4 p.m. – 9 p.m., unless otherwise stated.

Chart 1: SDG&E Circuit Peaks (Time Period)

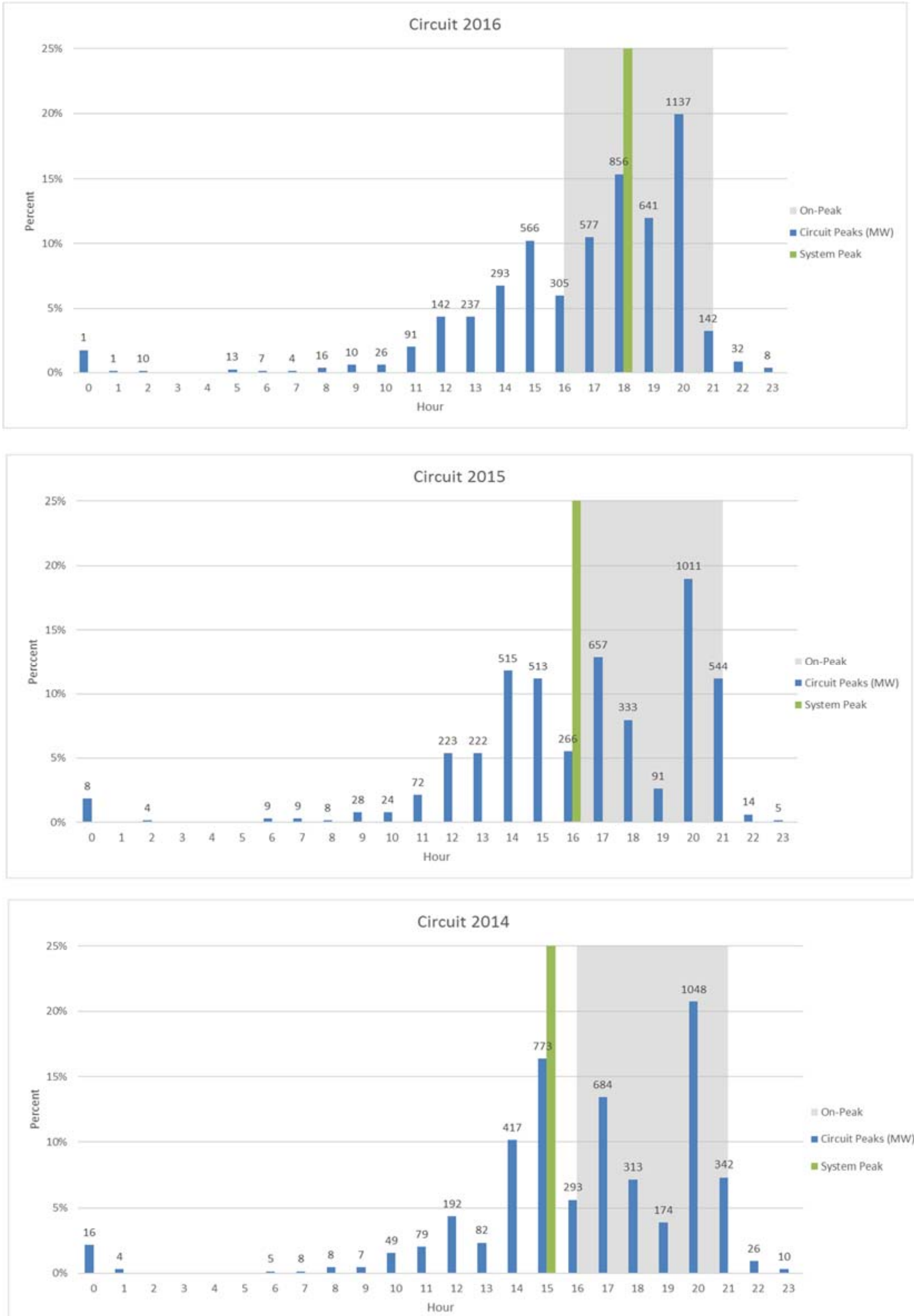
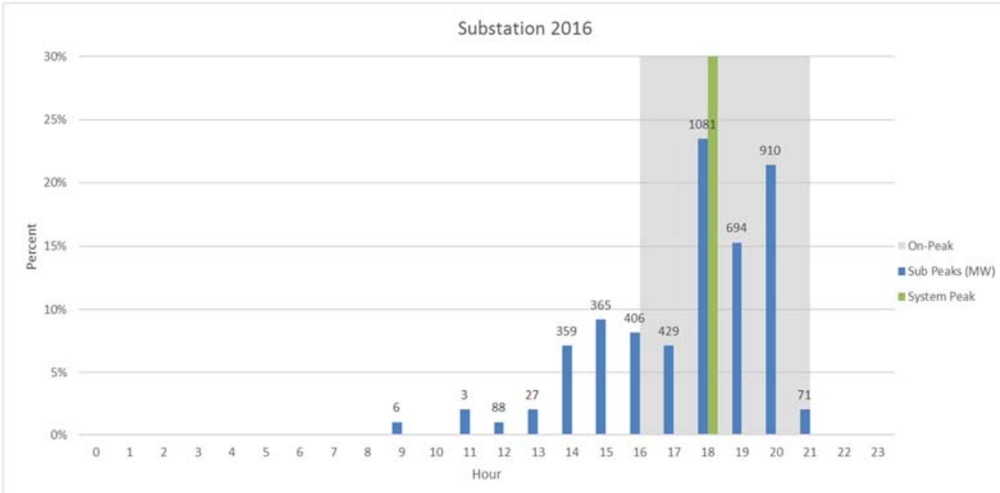
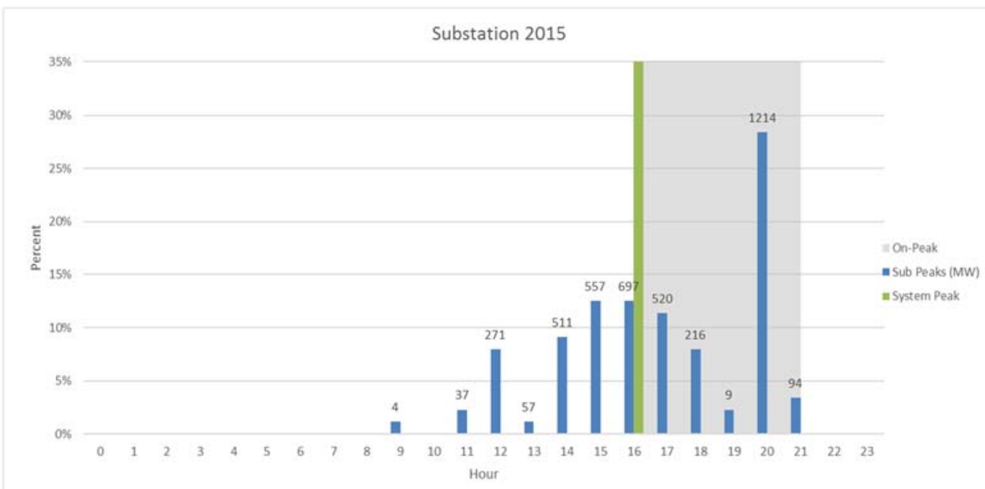
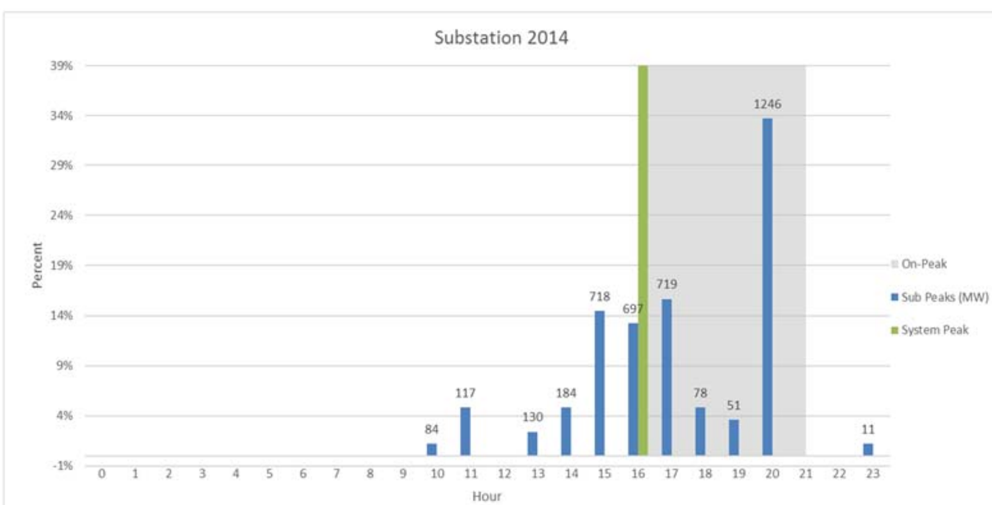


Chart 2: SDG&E Substation Peaks (Time Period)







As displayed in Table 4 below, between 58.2% and 67.0% of SDG&E's circuits peaked during the on-peak period. Table 5 shows that 71.1-76.8% of SDG&E's substations peak during the on-peak period.

Table 4: SDG&E Circuits Peaking During On-Peak TOU Period

		Circuit	
		On-peak (4pm - 9 pm)	All Other Hours
2014	Count (%)	58.2%	41.8%
	Total (MW)	2,854	1,676
2015	Count (%)	59.1%	40.9%
	Total (MW)	2,903	1,652
2016	Count (%)	67.0%	33.0%
	Total (MW)	3,658	1,456

Table 5: SDG&E Substations Peaking During On-Peak TOU Period

		Substation	
		On-peak (4pm - 9 pm)	Off-Peak
2014	Count (%)	71.1%	28.9%
	Total (MW)	2,791	1,245
2015	Count (%)	65.9%	34.1%
	Total (MW)	2,749	1,438
2016	Count (%)	76.8%	23.2%
	Total (MW)	3,590	848

Study 2 – As Modified by Commission

Step 1: As an alternate to its proposed Step 1 for distribution, SDG&E now assumes that 74% of its distribution costs are demand-related.

Specifically, Ordering Paragraph 2 of Resolution E-4951 requires that the study be modified such that:

(a) SDG&E uses the EPMC-based attribution of 74% of distribution costs as demand-related as the starting point, bypassing SDG&E's proposed Step 1 distribution cost analysis and proceeding directly to its Step 2 load analysis and,

(b) SDG&E provides that up to 74% of distribution cost could be subject to recovery in a peak-related demand charge, depending on the outcome of SDG&E's Step 2 load analysis.

See Attachments A1-A3 for this analysis. The results of this analysis show that 57.9% of the total distribution demand-related marginal costs revenues would be assigned to on-peak, as compared to SDG&E current allocation of approximately 61%. Correspondingly, 42.1% of the total distribution demand related marginal cost revenues would be allocated to non-coincident compared to SDG&E's current allocation of approximately 39%.

Additional Requirements

Ordering Paragraph 1 of Resolution E-4951 requires SDG&E to discuss how the data, methodology, and results of its distribution demand charge studies relate to the data, methodology and results of its Grid Needs Assessment ("GNA") and Distribution Deferral Opportunity Reports ("DDOR").

The methodology, and results of the distribution demand charge study are each independent of the methodology, and results of the GNA Report and the DDOR.

The distribution demand charge study uses the effective demand factor ("EDF") methodology to calculate each customer classes' contribution to circuit and substation peaks to determine the appropriate allocation of circuit and substation costs to customer classes and allocation between peak and non-coincident demand charges. The results of this study provide the appropriate allocation of costs between peak and non-coincident demand charges for distribution costs.

The GNA presents a list of elements that have a forecasted deficiency above existing facility or equipment rating within a 5-year range. The GNA is a generated report from the annual distribution planning process. The distribution planning process is an annual review and forecast of all distribution circuit and substation loads intended to identify any capacity deficiencies. The DDOR is a report of investment opportunities to address the GNA.

As described above, the distribution demand charge study, its methodology and results are independent of the GNA and DDOR's methodology, results, and overall reporting objectives. The results of one process are not related to the other.

ATTACHMENT A1

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-002 SUPPLEMENTAL TESTIMONY
SUPPLEMENTAL TESTIMONY - DISTRIBUTION DEMAND CHARGE STUDY

Commission Resolution E-4951 - Alternative Distribution Demand Charge Study Pursuant to Ordering Paragraph ("OP") 2
Distribution Demand-Related Marginal Costs

SDG&E Distribution Demand-Related Marginal Costs

Customer Classes	SDG&E Proposed ($000)[1]						
	Feeder & Local Distribution ("FLD")			**Substation**			**Total**
	Secondary	Primary	Total	Secondary	Primary	Total	
Residential	$127,345	$0	$127,345	$43,367	$0	$43,367	$170,712
Small Commercial	$38,561	$381	$38,942	$13,183	$130	$13,313	$52,255
Medium/Large Commercial & Industrial ("M/L C&I")	$99,802	$29,359	$129,162	$34,510	$10,152	$44,662	$173,824
Agricultural	$3,666	$499	$4,165	$1,288	$175	$1,463	$5,628
Lighting	$628	$0	$628	$248	$0	$248	$876
School	$5,087	$619	$5,706	$1,742	$212	$1,954	$7,660
System Total	$275,090	$30,858	$305,948	$94,338	$10,669	$105,007	$410,955
						Total Distribution Marginal Costs	$716,999
						% of Total Distribution Marginal Costs	**57.3%**

Alternative Distribution Demand Charge Study ($000)[2]

	FLD			**Substation**			**Total**
	Secondary	Primary	Total	Secondary	Primary	Total	
Residential	$164,413	$0	$164,413	$55,991	$0	$55,991	$220,404
Small Commercial	$49,786	$491	$50,277	$17,020	$168	$17,188	$67,465
Medium/Large Commercial & Industrial ("M/L C&I")	$128,853	$37,906	$166,759	$44,555	$13,107	$57,663	$224,422
Agricultural	$4,733	$644	$5,378	$1,663	$226	$1,889	$7,267
Lighting	$811	$0	$811	$320	$0	$320	$1,131
School	$6,568	$799	$7,367	$2,249	$274	$2,523	$9,890
System Total	$355,165	$39,840	$395,005	$121,798	$13,775	$135,574	$530,579
						Total Distribution Marginal Costs	$716,999
						% of Total Distribution Marginal Costs	**74.0%**

Notes:
(1) 2019 GRC Phase 2 (A.19-03-002); SDG&E Chapter 5 Direct Testimony Workpaper of William G. Saxe; "2019 GRC P2 Dist Rev Alloc (Chapter 5 Workpaper)" file.
(2) Commission Resolution E-4591, OP 2a.

ATTACHMENT A2

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-002 SUPPLEMENTAL TESTIMONY
SUPPLEMENTAL TESTIMONY - DISTRIBUTION DEMAND CHARGE STUDY

Commission Resolution E-4951 - Alternative Distribution Demand Charge Study Pursuant to Ordering Paragraph ("OP") 2
Capacity-Related Distribution Demand Marginal Costs

Step 1: Determine Capacity-Related Distribution Demand Costs		SDG&E Distribution Demand Charge Study[2,3]				Alternative Distribution Demand Charge Study[4]
Direct Capacity Costs ($000)		2017	2018	2019	3-Year Average	
	Distribution Capacity/Expansion Costs					
	Feeder & Local Distribution ("FLD" or "Circuit")	$8,253	$5,633	$9,108	$7,665	NA
	Substation	$5,016	$5,369	$16,068	$8,818	NA
	Sub-Total[1]	$13,269	$11,002	$25,176	$16,482	NA
	Transmission-Related (Associated with FLD)	$123	$1,140	$0	$421	NA
	Total	$13,392	$12,142	$25,176	$16,903	NA
Indirect Capacity Costs ($000)						
	Easements					
	FLD Capacity Cost Share of Easement Costs	$18.8	$13.1	$15.5	$15.5	NA
	Substation Capacity Cost Share of Easement Costs	$11.3	$10.4	$27.3	$16.9	NA
	Total	$30.1	$23.6	$42.8	$32.4	NA
	Overhead Pool - FLD Capacity Cost Share of Overhead Costs	$2,023.4	$1,591.5	$2,266.5	$1,958.1	NA
	Overhead Pool - Substation Capacity Cost Share of Overhead Pool Costs	$2,031.5	$3,967.7	$16,012.0	$6,590.3	NA
	Total	$4,054.9	$5,559.2	$18,278.5	$9,297.6	NA
Total Capacity-Related Costs ($000)						
	Feeder & Local Distribution	$10,418.3	$8,377.7	$11,390.0	$10,059.3	NA
	Substation	$7,058.8	$9,347.1	$32,107.4	$15,424.9	NA
	Total	$17,477.0	$17,724.8	$43,497.4	$25,484.1	NA
Total Capacity % of Total Distribution Marginal Costs (%)						
	Feeder & Local Distribution	3.1%	1.8%	2.1%	2.2%	NA
	Substation	14.6%	15.3%	33.1%	22.4%	NA
	Total	**4.5%**	**3.3%**	**6.7%**	4.9%	NA
Distribution Demand-Related Costs to Recover in On-Peak Demand Charges (%)					**4.9%**	**100%**

Notes:
(1) SDG&E Demand Charge Research Study - Distribution.
(2) 2019 GRC Phase 1 (A.17-10-007); Ex. SDGE-14-R/Ex. 74 Direct Testimony of Alan F. Colton, Appendix A.
(3) 2019 GRC Phase 2 (A.19-03-002); SDG&E Chapter 5 Direct Testimony Workpaper of William G. Saxe; "2019 GRC P2 Marg Dist Demand Costs (Chapter 5 Workpaper)" file.
(4) Commission Resolution E-4591, OP 2. As stated in OP 2a, under the alternative demand charge study SDG&E's proposed Step 1 distribution cost analysis to determine its distribution capacity-related demand costs is bypassed and instead 100% of the 74% in distribution demand-related costs could be subject to recovery in an on-peak demand charge depending on the outcome of Step 2 of the alternative distribution demand charge process, as stated in OP 2b.

ATTACHMENT A3

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-002 SUPPLEMENTAL TESTIMONY
SUPPLEMENTAL TESTIMONY - DISTRIBUTION DEMAND CHARGE STUDY

Commission Resolution E-4951 - Alternative Distribution Demand Charge Study Pursuant to Ordering Paragraph ("OP") 2
On-Peak Capacity-Related Distribution Demand Marginal Costs

	SDG&E Distribution Demand Charge Study[1]			Alternative Distribution Demand Charge Study[2]
Forecasted On-Peak Capacity-Related Distribution Demand Costs				
Feeder & Local Distribution ("FLD")	**On-Peak MWs**	**Off-Peak MWs**	**On-Peak MW %**	**On-Peak MW %**
2014	2,854	1,676	63.0%	52.2%
2015	2,903	1,652	63.7%	54.0%
2016	3,658	1,456	71.5%	64.2%
3-Year Average	3,138	1,595	66.3%	56.8%
Substation				
2014	2,791	1,245	69.2%	59.5%
2015	2,749	1,438	65.7%	53.3%
2016	3,590	848	80.9%	70.5%
3-Year Average	3,044	1,177	72.1%	61.1%
Forecasted Total Capacity % of Total Distribution Marginal Costs				
FLD			2.2%	100.0%
Substation			22.4%	100.0%
Forecasted Summer On-Peak Related Marginal Distribution Capacity Cost %				
FLD			1.5%	56.8%
Substation			16.2%	61.1%
M/L C&I Distribution Demand-Related Marginal Cost Revenues				
Total Marginal Distribution Demand Cost Revenues ($000)				
FLD			$129,162	$166,759
Substation			$44,662	$57,663
			$173,824	$224,422
On-Peak Distribution Demand Costs ($000)				
FLD			$1,895	$94,736
Substation			$7,226	$35,230
Total			$9,121	$129,966
Percentage of Total Distribution Demand-Related Marginal Cost Revenues			*5.2%*	*57.9%*
Non-Coincident Distribution Demand Costs ($000)				
FLD			$127,267	$72,023
Substation			$37,436	$22,432
Total			$164,702	$94,455
Percentage of Total Distribution Demand-Related Marginal Cost Revenues			*94.8%*	*42.1%*

Notes:
(1) SDG&E Demand Charge Research Study - Distribution.
(4) Commission Resolution E-4591, OP 2b and p. 11 that requires the modification to SDG&E's Step 2 circuit and substation load analysis, as proposed by The Public Advocates Office, formerly known as the O

Attachment B

Generation Demand Charge Study Results

SDG&E Demand Charge Research Study – Generation

Introduction

This study is presented to describe San Diego Gas and Electric Company's ("SDG&E") examination of the appropriate allocation of generation capacity costs between volumetric and peak demand charges and whether a shorter duration peak demand period for assessing coincident peak-related demand charges should be established relative to the adopted time-of-use period,[1] as directed by the California Public Utilities Commission ("CPUC" or "Commission") in Decision ("D.) 17-08-030 and Resolution E-4951. This study is provided as supplemental testimony to its 2019 General Rate Case ("GRC") Phase 2, Application ("A.") 19-03-002, which was filed on March 4, 2019.

More specifically, in SDG&E's 2016 GRC Phase 2, D.17-08-030, the CPUC directed SDG&E to:

"[C]onduct a study to examine the appropriate allocation of generation capacity costs between volumetric and peak demand charges and whether a shorter duration peak demand period for assessing coincident peak-related demand charges should be established, relative to the adopted time-of-use period, to be included in the next San Diego Gas & Electric Company Phase 2 General Rate Case. San Diego Gas & Electric Company must consult with parties to this proceeding in preparing its research plan for the study and file the research plan as a Tier 2 Advice Letter within 120 days of the effective date of this decision."[2]

Additionally, in Resolution E-4951, the CPUC ordered that SDG&E modify its study to provide information on "how its generation study models ramping and renewables integration, and how it separates generation capacity costs into peak-related and non-peak related components."[3]

SDG&E solicited feedback from various parties in development of its research plan, including:

- Receiving written feedback during initial study scope development;
- Verbal feedback during November 1, 2017 and December 7, 2017 telephonic workshops; and
- Additional written feedback on draft scope document and the near final scope document.

SDG&E filed Advice Letter ("AL") 3166-E on December 21, 2017, which detailed the Demand Charge Research Plan. On September 13, 2018, the CPUC adopted Resolution E-4951, which approved, with modifications, SDG&E's proposed generation demand charge research plan, to

[1] Resolution E-4951, Ordering Paragraph ("OP") 1c.
[2] D. 17-08-030, OP 35.
[3] Resolution E-4951, OP 1b.

be filed as supplemental testimony in its GRC Phase 2 proceeding within 60 days of filing its 2019 GRC Phase 2 application.[4]

This study is divided into three sections:

1) Generation Capacity Cost Allocation using the Loss of Load Expectation ("LOLE") Methodology.

2) Incorporation of Ramping and Renewable Integration.

3) Discussion: Shorter duration peak demand period for assessing peak-related demand charges.

Section 1 – Generation Capacity Cost Allocation using the LOLE Methodology

SDG&E uses a LOLE analysis methodology for the allocation of capacity costs to the peak period. The LOLE analysis provides the expectation of the hours with the highest need for new resources given the variable nature of customer demands due to weather and the variable nature of solar and wind energy production. Also, given the changing mix of generation resources and the changing load profile of customer demand over time, the drivers of generation capacity needs may change. LOLE analysis can reflect these changes in future years and inform SDG&E's allocation of generation capacity costs to peak demand charges. The CPUC stated that "SDG&E's proposal to use a 'Loss of Load Event (LOLE)' methodology to allocate generation capacity costs to the peak period is reasonable."[5]

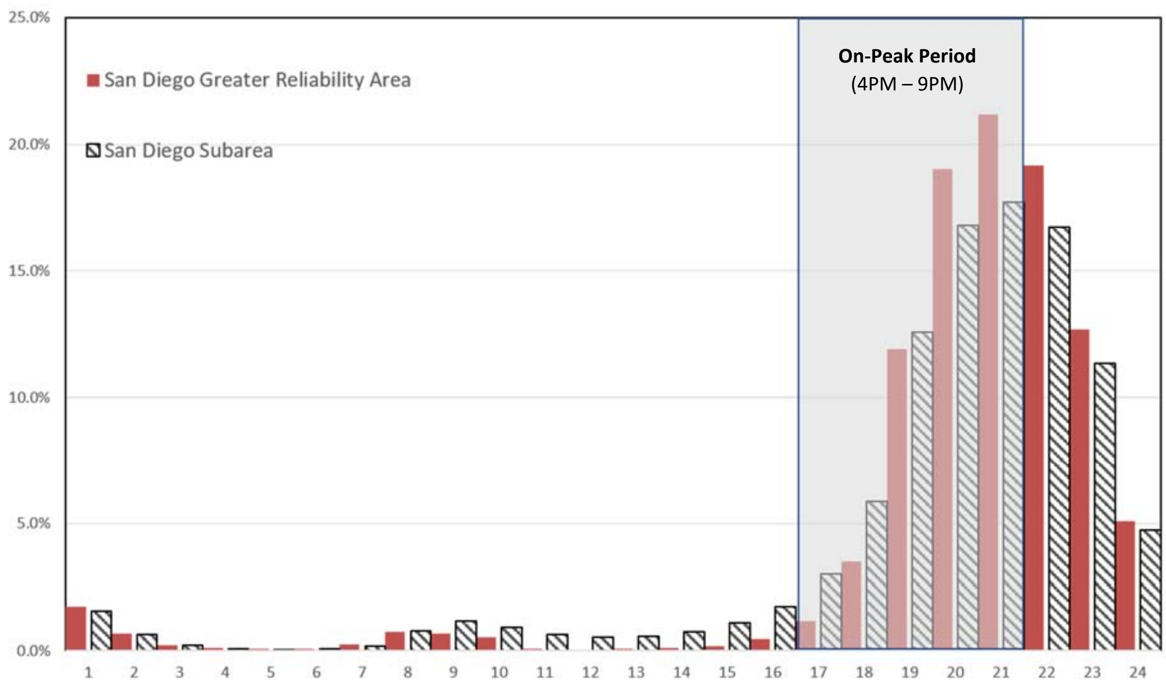
Loss of Load Probability, "LOLP" is the probability of not meeting load in an hour when key system variables are analyzed stochastically, and is the result of the LOLE analysis. SDG&E determined the LOLE for the SDG&E system using the ABB Planning and Risk model ("Planning and Risk model"), a system dispatch model tailored to the SDG&E system.[6] In order to model real world uncertainties, different load and variable renewable production levels are generated by a stochastic process based on historical data. The Planning and Risk model then performs an hourly economic dispatch of generation resources against loads for each hour of the

[4] Resolution E-4951, OP 1. Filing by May 3, 2019 is within the 60-day requirement.
[5] Resolution E-4951, Finding of Fact 17.
[6] The Planning and Risk Model use in SDG&E's Generation Demand Charge Research Study is the same production cost model used by SDG&E to forecast procurement costs in the Energy Resource Recovery Account ("ERRA") proceeding. The focus in this analysis is on local capacity and the needs for local capacity that can be reduced through the use of appropriate consumer price signals in time-of-use ("TOU") periods and demand response availability periods to provide incentives for load modification. The Planning and Risk model accommodates detailed hour-by-hour simulation of the operations of electric systems. It considers a complex set of generation operating constraints to simulate the least-cost operation of the system. The model's unit commitment and dispatch logic is designed to mimic "real world" power system hourly operation, minimizing system production cost, enforcing the constraints specified for the system, generation stations, associated transmission, fuel, etc.

year. By running multiple iterations of the model, a probability distribution of hours with relative expected loss of load can be developed.

Available generation resources in the analysis include generation units (both new renewable and conventional generation) that exist or are expected to be constructed by 2020 in the San Diego Greater Reliability area (both SDG&E service area and Imperial Valley). SDG&E is unique in that local capacity is defined in both the San Diego Greater Reliability area and separately in the San Diego sub-area (excluding generation from Imperial Valley). SDG&E analyzed LOLE for both areas separately and combined. The resulting analysis is not a measure of need for new capacity, but, instead, if there were a need, what hours of the year would experience the highest likelihood of a loss of load. Figure 1 displays SDG&E's LOLE for both areas:

Figure 1: Relative Loss of Load Expectation for the San Diego Local Capacity Areas by Hour Ending



<u>Results</u>

SDG&E summed the LOLE analysis results by TOU period for all hours of the simulation year. This resulted in an allocation of 56% of the unserved energy occurring during the standard TOU on-peak hours of 4 p.m. – 9 p.m. (shaded area in Figure 1) and 44% to all other hours. See Figure 2 below for the allocation of LOLE by TOU period.

Figure 2: LOLE Probability by TOU Period

LOLE % by TOU Period	
Standard TOU Periods	**Allocation**
On-peak : 4pm - 9pm daily	56.0%
Off-peak: All other hours	41.0%
Super off-peak: 12am - 6am non-holiday weekdays and 12am - 2pm weekends/holidays	3.0%
Total	100.0%

These allocation percentages in Figure 2 represent allocation factors that should be applied to capacity costs to represent peak-related and non-peak related cost components per SDG&E's approved Generation Demand Charge Research Plan. SDG&E utilized GRC Phase 1 approved revenue requirements for utility owned generation ("UOG") and conventional PPA demand charges from its Federal Energy Regulatory Commission ("FERC") Form 1, *Electric Utility Annual Report*, which is filed annually and contains comprehensive financial and operating data. Applying these allocation percentages to these capacity charges reported in GRC Phase 1 of the FERC Form 1 for the years 2016 through 2018 results in the allocation of costs shown in Figure 3.

Figure 3: Allocation of FERC Form 1 Capacity Costs (2016-2018)

	2016	2017	2018
UOG Conventional Non-fuel Expense	$214,272,728	$226,814,000	$232,598,000
PPA Conventional Demand Charges	$198,131,460	$180,728,609	$136,445,282
Total Capacity Related Charges	**$412,404,188**	**$407,542,609**	**$369,043,282**
Peak Related % Allocation	56%	56%	56%
Non-peak Related % Allocation	44%	44%	44%
Peak Related Charges	**$230,946,345**	**$228,223,861**	**$206,664,238**
Non-peak Related Charges	**$181,457,843**	**$179,318,748**	**$162,379,044**

Section 2 – Incorporation of Ramping and Renewable Integration

The CPUC also requested that SDG&E provide information on "how its generation study models ramping and renewables integration."[7] SDG&E's LOLE analysis does not yet incorporate ramping and renewable integration characteristics. However, SDG&E recognizes the need to consider accounting for ramping and renewables in its generation studies in the future and is currently participating in Southern California Edison Company's ("SCE") 2021 GRC Phase 2 Working Group established to "discuss how to incorporate a flexible generation capacity component into the revenue allocation process in addition to a peak capacity component."[8]

In the meantime, SDG&E's current LOLE analysis provides a reasonable allocation of SDG&E's existing capacity costs. Currently, all conventional generation capacity owned or contracted by SDG&E contributes to peak reliability. None of SDG&E's current conventional generation portfolio was explicitly acquired to serve ramping, flexibility, or other renewable integration needs. To the extent that all of the conventional generation resources in SDG&E's portfolio have varying degrees of flexibility to serve ramping and renewable integration needs, it can be inferred that when not dispatched to serve peak related needs, conventional generation is available to provide ramping, flexibility, or other renewable integration needs.

SDG&E recognizes that to meet greenhouse gas- ("GHG") related mandates, the need for renewable integration capability is likely to increase in the future. Therefore, SDG&E looks forward to participating in SCE's 2021 GRC Phase 2 Working Group which, at the time of this filing, is in the process of being established. SDG&E expects to be able to better assess the need to integrate modeling of ramping and renewable integration needs once the Working Group is underway.

Section 3 – Discussion: Shorter duration peak demand period for assessing peak-related demand charges

The Commission also directed SDG&E to revise the generation demand charge research plan to address the issue of whether a shorter duration peak demand period for assessing coincident peak-related demand charges should be established, relative to the adopted time-of-use period.[9]

D.17-08-030 recently adopted new TOU periods which were implemented on December 1, 2017, which resulted in a shorter summer on-peak period, previously seven consecutive hours (11 a.m. to 6 p.m.) to five consecutive hours (4 p.m. to 9 p.m.). On-peak generation capacity demand charges are assessed during this standard on-peak TOU period and are intended to

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[7] Resolution E-4951, OP 1b.
[8] A.17-06-030, Revenue Allocation Settlement Agreement at 22, attached as Attachment A to *Amended Motion of [SCE] and Settling Parties for Adoption of Revenue Allocation Settlement Agreement* (July 13, 2018), and approved by D.18-11-027 at 16."
[9] Resolution E-4951, OP 1c.

incentivize customers to modify their behavior and shift usage when SDG&E's peak demand occurs. In compliance with D.17-08-030, SDG&E included in this study the information to examine whether a shorter duration peak demand period of assessing generation capacity peak-related demand charges should be established, relative to SDG&E's recently adopted standard on-peak TOU period of 4 p.m. to 9 p.m.

SDG&E's current rate structure has on-peak demand charges for certain Medium/Large Commercial and Industrial ("M/L C&I") and Agricultural rate schedules based on its generation capacity costs. SDG&E's methodology for assessing these peak demand charges for generation costs is based on a customer's highest 15-minute demand (kW) interval during its on-peak period, from 4 p.m. – 9 p.m., weekdays and weekends for all seasons. Currently, SDG&E recovers 50% of generation capacity costs in an on-peak demand charge for its default M/L C&I rate schedule and 20% of these costs in an on-peak demand charge for its default large Agricultural schedule.[10]

The Commission's decision to require SDG&E to reexamine its on-peak period for on-peak generation demand charges appears to be based on the assumption that a "customer's maximum 15-minute interval demand could occur on a different day than the system maximum demand, which could result in a solar customer being under-credited for the capacity provided by the customer's rooftop solar system."[11] The above could be an accurate assumption if every solar customer has sized their system to meet their maximum demand, and, if the customer did not have their maximum demand concurrent with system peak, they would be providing capacity that is not accounted for. However, the opposite could also be true for solar customers. Those customers could be peaking at the same time as the system peak, at a level that is higher than the individual capacity provided to their home by their individual solar system. SDG&E's standard on-peak period is 4 p.m. – 9 p.m., and, as displayed in Figure 1, the greatest probability for need for SDG&E system capacity occurs after 7:00 p.m., when solar generation potential is minimal, if present at all.

Additionally, SDG&E only recently changed its TOU periods, effective December 1, 2017 per D.17-08-030. Creating a new, shorter, period for assessing on-peak demand charges after only recently instituting new TOU periods and requiring a different on-peak period for on-peak generation demand charges than on-peak volumetric charges is unnecessarily complicated and will likely cause customer confusion and frustration.

Regardless of the volumetric TOU period definition or peak demand charge assessment period definition, the high cost hours will continue to be the high cost hours. For TOU periods to be effective in aligning costs, the TOU definitions should provide a group of high cost hours, which, for SDG&E, as displayed in Figure 1, span more than two hours. TOU periods that follow this guidance will create price signals that provide customers with information about the high cost

[10] The Commission required SDG&E to maintain its allocation of generation capacity costs to an on-peak demand charge in D.17-08-030, at 50.
[11] D.17-08-030, at 49-50.

hours and thereby incent economically efficient behavior that reduces system costs when customers shift their usage to a low-cost time period. TOU periods that fail to follow this guidance will result in high-cost hours in multiple TOU periods, which will result in both muted TOU differentials and less meaningful price signals, including those from on-peak generation demand charges. Creating a shorter, two-hour on-peak period for assessing generation demand charges would not achieve customer behavior shifting to low-cost hours, as the charge is intended to incent, and would result in high-cost hours outside the on-peak period, muting the price signal. Since the definition of TOU periods are intended to provide customers with accurate information regarding the high-cost periods for commodity services and the low-cost periods for commodity services, the on-peak period for generation demand charges and volumetric charges should not be different, as their intent to incentivize customers to shift behavior is the same.

Based on Figure 1 above, which displays SDG&E's most recent LOLP analysis, SDG&E sees its greatest need for capacity during the evening hours, from hours ending 16 to 24, in both the San Diego Greater Reliability Area and San Diego Subarea. When looking at the distribution of this need, over the hours with greatest need (5% LOLP or greater), SDG&E's LOLP shape resembles a normal distribution, and does not show a distribution that would support adoption of a shorter-duration period for assessing on-peak demand charges. SDG&E's methodology for assessing on-peak demand charges based on a customer's highest 15-minute interval demand during the on-peak period is appropriate and should not be modified.

Attachment C

Transmission Demand Charge Study Results

Christopher M. Lyons
Senior Counsel
San Diego Gas & Electric Company
8330 Century Park Court, CP32D
San Diego, CA 92123
Tel: 858-654-1559
Fax: 619-699-5027
clyons@semprautilities.com

March 4, 2019

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20246

Re: SDG&E Demand Charge Research Study – Transmission
<u>Docket No. ER19-221-000</u>

Dear Secretary Bose:

Enclosed for filing, for informational purposes, is San Diego Gas & Electric Company's ("SDG&E") *Demand Charge Research Study – Transmission* ("Study"). This Study is being submitted at the direction of the California Public Utilities Commission ("CPUC"), SDG&E's state regulator. SDG&E is submitting this study for informational purposes and is not proposing any changes to its rates, terms or conditions of service in this or any other docket.

On August 25, 2017, the CPUC issued its *Decision Adopting Revenue Allocation and Rate Decision for San Diego Gas & Electric Company*,[1] a decision concerning certain retail rate design and allocation issues arising in what is referred to as Phase 2 of its General Rate Case ("GRC Phase 2"). In that decision, the CPUC stated:

> SDG&E is directed to conduct a study to examine the appropriate allocation of distribution costs between noncoincident demand charges and system peak demand charges to be included in SDG&E's next GRC Phase 2 proceeding and conduct a study to examine the appropriate allocation of transmission costs between noncoincident demand charges and system peak demand charges to be filed at the FERC prior to SDG&E's next GRC Phase 2.[2]

1 Decision 17-08-030.
2 *Id.*, p. 47.

In accordance with that direction, SDG&E has conducted the Study and has enclosed it with this letter.

Please contact me if you have any questions or concerns.

Respectfully submitted,

/s/ Christopher M. Lyons

Attorney for San Diego Gas & Electric Company

Enclosure

cc: Service List, Docket No. ER19-221-000

SDG&E Demand Charge Research Study – Transmission

Introduction

This study is presented to describe San Diego Gas and Electric Company's ("SDG&E") examination of the allocation of costs between non-coincident and system peak demand charges relating to transmission costs. Non-coincident demand represents a customer's maximum demand without regard to when the demand occurred whereas system peak demand (also referred to as "on-peak demand") represents a customer's maximum demand during SDG&E's on-peak period, which, as adopted in Decision ("D.") 17-08-030, is 4 PM – 9PM every day of the year for SDG&E's standard, non-grandfathered Time-of-Use ("TOU") periods.

As directed by the California Public Utilities Commission ("CPUC"), SDG&E conducted a study to examine the appropriate allocation of transmission costs between non-coincident demand charges and system peak demand charges, as well as the system peaks and relationship to customer class demand. The research plan aimed to determine the percentage of transmission costs driven by capacity or peak needs, using transmission project costs from the most recently filed transmission rate case.

In SDG&E's 2016 General Rate Case ("GRC") Phase 2, D.17-08-030, the CPUC directed SDG&E to:

- "[E]xamine the appropriate allocation of transmission costs between noncoincident demand charges and system peak demand charges to be filed at the Federal Energy Regulatory Commission ["FERC"] prior to the next San Diego Gas & Electric Company Phase General Rate Case. San Diego Gas & Electric Company must consult with parties to this proceeding in preparing its research plan for the study and file the research plan as a Tier 2 Advice Letter within 120 days of the effective date of this decision."[1]

SDG&E solicited feedback from various parties in development of its research plan, including:

- Receiving written feedback during initial study scope development;
- Verbal feedback during November 1, 2017 and December 7, 2017 telephonic workshops; and
- Additional written feedback on draft scope document and the near final scope document.

SDG&E's final research plan proposed a two-step process for the transmission study. SDG&E proposed to: (1) determine the percentage of transmission costs driven by capacity-related or peak needs; and (2) examine customer class load at the system level that occurs: (i) within the

[1] D.17-08-030 Ordering Paragraph ("OP") 34.

currently-defined on-peak TOU period; and (ii) outside of the currently-defined on-peak TOU period.

SDG&E filed Advice Letter ("AL") 3166-E on December 21, 2017, which detailed the Demand Charge Research Plan. On September 13, 2018, the CPUC adopted Resolution E-4951, which approved, with modifications, SDG&E's proposed demand charge research plan, and directed SDG&E to perform parallel studies of its transmission demand charges based on an alternative cost classification methodology as described in the Resolution.[2]

The CPUC required modification of SDG&E's transmission demand charge study to include the following supplemental information:

- How its transmission studies use its load data to separate demand-related transmission costs into peak-related and non-coincident demand charge components[3];
- An alternate transmission demand charge study, filed concurrently with its proposed transmission demand charge study, with the following revised parameters:
    - SDG&E shall use the CAISO's attributed of a fixed percentage of transmission costs as demand-related as the starting point, bypassing SDG&E's proposed Step 1 transmission cost analysis and proceeding directly to its Step 2 load analysis.
    - SDG&E's alternate study shall assume that 50% of transmission cost is demand-related per CAISO's January 11, 2018 "Straw Proposal" in its Transmission Access Charge ["TAC"] Structure stakeholder initiative, subject to any updates to CAISO's TAC proposal as they become available.
    - SDG&E's alternate study shall assume recovery of up to 50% of transmission costs in a peak-related demand charge, depending on the outcome of SDG&E's Step 2 load analysis.[4]

The Planning Process

Through SDG&E's internal transmission assessment and planning processes, and in partnership with the California Independent System Operator's ("CAISO") annual transmission planning process ("TPP"), the transmission system is annually evaluated to identify potential system limitations, as well as opportunities to improve reliability and efficiency. In addition to SDG&E's internal review and approval processes, all capacity driven-projects must be approved by the CAISO through the TPP.

Research Plan

The research plan consisted of the following steps:

Study Step 1: Examination of capacity-related transmission costs

1. Classify the approved transmission projects into categories that describe principle drivers (purpose).

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[2] Resolution E-4951, OPs 1-3.
[3] Resolution E-4951, OP 1.
[4] Id. at OP 3.

2. Collect data related to all transmission projects that have been approved and had a capital spend during the 2012 through 2017 period.
3. Collect data related to all transmission projects that have been approved, as applicable, by the CAISO, SDG&E, and the CPUC and have a projected capital spend during the 2018 through 2022 period.
4. Determine the principle drivers for each project.
5. Allocate project cost among principle drivers (if there is more than one principle driver).
6. Aggregate the capital spend by each category of principle driver.

Study Step 2: Examination of customer class load

1. Collect hourly load data from 2014 through 2016 at the customer class level.
2. Quantify the customer class load at the system level that occurs within the currently-defined on-peak TOU period.
3. Quantify the customer class load at the system level that occurs outside of the currently-defined on-peak TOU period.

Study Step 1

Categorization of Costs

Transmission projects may be driven by one or more of the following:

- *Reliability requirements*: projects required to meet growth in peak demand and maintain a reliable grid under contingency conditions (e.g., the forced outage of one or more transmission lines) that can occur at any time.
- *Policy obligations*: projects intended to connect, deliver, and integrate renewable resources to meet the Renewable Portfolio Standards ("RPS") and Greenhouse Gas ("GHG") reduction goals.
- *Economics*: projects where there is an economic benefit to consumers from reducing the Local Capacity Requirements ("LCR") or minimizing congestion-related costs sufficient to offset the cost of a transmission upgrade.
- *Maintenance*: projects intended to replace aging infrastructure, relocate existing facilities, and/or improve the safety of the grid.

It is important to note that various transmission projects served more than one purpose and therefore fall into more than one principle driver category. For example, the Sunrise Powerlink project had multiple drivers.

Approved Projects Cost Data

SDG&E collected data on 160 transmission projects that have been approved and that have capital spend during the period 2012 through 2022. The total capital spent during the 2012 through 2017 period was approximately $2.95 billion, while the projected capital spend from 2018 through 2022 is approximately $1.5 billion.

Project Classification

In determining the appropriate principle driver categorization for each project, SDG&E assessed the purpose of each project which, typically, is illustrated in the project description or evident from related regulatory filings, detailed summary, and any supporting documentation. SDG&E has described examples of projects that are typically driven by peak demand and those that are not driven by peak demand below.

Typical Peak Demand-Driven Projects

SDG&E classified the following types of projects as peak demand-driven:

- Building a new transmission line;
- Reconductoring an existing line;
- Reconfiguring an existing line;
- Building a new substation;
- Expanding an existing substation;
- Adding/upgrading transformers; and
- Adding Capacitors/Condensers to provide voltage and reactive power support.

Typical Non-Demand-Driven Projects

SDG&E classified the following types of projects as non-peak-driven:

- Participating Transmission Owner ("PTO") generation interconnection facilities;
- Substation and/or facilities relocation;
- Wood to steel pole replacement ("fire hardening");
- Aging infrastructure replacement;
- Supporting public policy requirements or goals (e.g. Renewable Portfolio Standard ("RPS") requirements);
- Building facilities to reduce local capacity requirements ("LCR") or reduce congestion;
- Building facilities necessary for safety; and
- Grid control, visibility, and measurement enhancements.

Study Period & Results

To evaluate the appropriate breakdown of costs associated with growth in peak demand versus other reasons, three spending periods were analyzed to assess the robustness of the conclusions reached. SDG&E analyzed the past five years of data (2012 – 2017), the past two years of data (2015 – 2017), and a five-year forecast (2018 – 2022). SDG&E chose to analyze these periods to gain confidence with the results. The detailed results of each period are presented below:

Period 1: Projects with capital spend during the 2012 through 2017 period (historical data).

- Results indicate approximately 30.6% (Category 1) of capital spend is primarily driven by growth in peak demand and approximately 69.4% (Categories 2-10) is primarily driven by other factors.

Table 1 – SDG&E Transmission Cost Details
Study Period 1: Years 2012 – 2017 ($ thousands)

Category	**Total Spent**	**Percent of Total**
1. Provide reliable service under peak load conditions.	$ 901,740	30.6%
2. Interconnect new generation.	$ 193,720	6.6%
3. Interconnect new load.	$ 75,782	2.6%
4. Improve grid efficiency (e.g., reduce Local Capacity Requirements, reduce congestion-related costs, reduce losses).	$ 104,299	3.5%
5. Support public policy requirements or goals (e.g., Renewable Portfolio Standard (RPS) requirements).	$ 695,593	23.6%
6. Upgrade, repair or replacement of existing facilities (e.g., adding spare transformer, replacing old direct-buried cable).	$ 285,896	9.7%
7. Relocation or removal of facilities (e.g., under-grounding, accommodate third-party customer construction).	$ 234,095	7.9%
8. Customer and/or employee safety (e.g., fire-hardening).	$ 341,139	11.6%
9. Grid visibility, control and measurement.	$ 75,361	2.6%
10. Provide reliable service under conditions not driven by peak load.	$ 42,418	1.4%
Total	$ 2,950,043	100.0%

Period 2: Projects with capital spend during the 2015 through 2017 period (historical data).

- Results indicate approximately 37.2% (Category 1) of capital spend is primarily driven by growth in peak demand and approximately 62.8% (Category 2-10) is primarily driven by other factors.

Table 2 – SDG&E Transmission Cost Details
Study Period 2: Years 2015 – 2017 ($ thousands)

Category	**Total Spent**	**Percent of Total**
1. Provide reliable service under peak load conditions.	$ 548,714	37.2%
2. Interconnect new generation.	$ 103,500	7.0%
3. Interconnect new load.	$ 32,119	2.2%

4. Improve grid efficiency (e.g., reduce Local Capacity Requirements, reduce congestion-related costs, reduce losses).	$ 56,913	3.9%
5. Support public policy requirements or goals (e.g., Renewable Portfolio Standard (RPS) requirements).	$ 169,719	11.5%
6. Upgrade, repair or replacement of existing facilities (e.g., adding spare transformer, replacing old direct-buried cable).	$ 127,955	8.7%
7. Relocation or removal of facilities (e.g., under-grounding, accommodate third-party customer construction).	$ 169,164	11.5%
8. Customer and/or employee safety (e.g., fire-hardening).	$ 226,748	15.4%
9. Grid visibility, control and measurement.	$ 37,828	2.6%
10. Provide reliable service under conditions not driven by peak load.	$ 3,247	0.2%
Total	$ 1,475,908	100.0%

Period 3: Projects with capital spend during the forecasted 2018 through 2022 period.

- Results indicate approximately 34.9% (Category 1) of capital spend is primarily driven by growth in peak demand and approximately 65.1% (Category 2-10) is primarily driven by other factors.

Table 3 – SDG&E Transmission Cost Details
Study Period 3: Years 2018 – 2022 ($ Thousands)

Category	**Total Spent**	**Percent of Total**
1. Provide reliable service under peak load conditions.	$ 523,129	34.9%
2. Interconnect new generation.	$ 4,927	0.3%
3. Interconnect new load.	$ 5,363	0.4%
4. Improve grid efficiency (e.g., reduce Local Capacity Requirements, reduce congestion-related costs, reduce losses).	$ 1,441	0.1%
5. Support public policy requirements or goals (e.g., Renewable Portfolio Standard (RPS) requirements).	$ 58,237	3.9%
6. Upgrade, repair or replacement of existing facilities (e.g., adding spare transformer, replacing old direct-buried cable).	$ 237,864	15.9%
7. Relocation or removal of facilities (e.g., under-grounding, accommodate third-party customer construction).	$ 29,570	2.0%
8. Customer and/or employee safety (e.g., fire-hardening).	$ 608,573	40.6%
9. Grid visibility, control and measurement.	$ 31,102	2.1%

10. Provide reliable service under conditions not driven by peak load.	$ 187	0.0%
Total	$ 1,500,392	100.0%

As displayed in Table 4, when comparing costs whose principal driver is peak demand-driven versus those that are not peak demand-driven, the results are closely matched, regardless of the period evaluated.

Table 4: Summary of Transmission Demand Charge Study Results

	Percentage of Peak-Driven Costs	Percentage of non-Peak-Driven Costs
Period 1: 2012-2017	30.6%	69.4%
Period 2: 2015-2017	37.2%	62.8%
Period 3: 2018-2022	34.9%	65.1%
Modified Study (Resolution 4951-E)	50%	50%

Study Step 2

Load Data

SDG&E examined its system-level peaks and customer class contributions to those peak demands.:

- The maximum system peak with the applicable dates and times for each year (Figure 1); and
- Each customer class' % share of maximum system peak demand.

None of the system peaks from 2014-2016 fell outside of SDG&E's current on-peak period (4:00 PM – 9:00 PM every day of the year), which was implemented on December 1, 2017. The standard on-peak period for the years presented below (2014-2016) was 11:00 AM – 6:00 PM on summer weekdays and 5:00 PM – 8:00 PM on winter weekdays. SDG&E presents the results of the system peak and each class's peak below:

Figure 1 – SDG&E System Peak (MW) 2014-2016

Year	System Peak (MW)	Date	Time
2014	4,887	9/16/2014	4:00:00 PM
2015	4,701	9/9/2015	4:00:00 PM
2016	4,334	9/26/2016	6:00:00 PM

Figure 2 – Customer Percentage Share at System Peak Demand (2014 – 2016)

Customer Class	2014	2015	2016
Residential	44.27%	43.09%	46.33%
Small Commercial	11.06%	10.84%	9.90%
M/L Commercial & Industrial	43.78%	45.18%	42.71%
Agricultural	0.89%	0.89%	0.90%
Streetlighting	0.00%	0.00%	0.15%

SDG&E also segmented the system-level energy for 2014 - 2016 to determine the percentages for each time of use period. The results in this instance show relative consistency among the years between the split of peak (25%) and non-peak period (75%).

Table 5: System-Level Energy Usage Allocation by Period

YEAR	OFF PEAK	ON PEAK	SUPER OFF	TOTAL
2014	44%	24%	31%	100%
2015	44%	24%	31%	100%
2016	44%	25%	32%	100%

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding. Dated at San Diego, California, this 4th day of March, 2019.

/s/ Jenny Norin

Jenny Norin
Sr. Legal Administrative Assistant
SDG&E
8330 Century Park Court, CP32D
San Diego, CA 92123
858-654-1716