BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application Of Southern California Edison Company (U 338-E) For Authority To Increase Its Authorized Revenues For Electric Service In 2018, Among Other Things, And To Reflect That Increase In Rates.	Application 16-09-001 (Filed September 1, 2016)

DIRECT TESTIMONY OF CURT VOLKMANN

ON BEHALF OF

THE SOLAR ENERGY INDUSTRIES ASSOCIATION AND VOTE SOLAR

May 2, 2017

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1 Introduction

Q. Please state your name and business address.

A. My name is Curt Volkmann. My business address is 290 Vine Avenue, Lake Forest, Illinois.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of the Solar Energy Industries Association ("SEIA") and Vote Solar.

Q. What is SEIA?

A. SEIA is the national trade association of the United States solar industry. Through advocacy and education, SEIA and its 1,000 member companies work to make solar energy a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy. SEIA's members have a strong interest in the adoption and implementation of policies and programs that will accelerate the movement toward a low-carbon economy and stimulate the development and use of zero-carbon, renewable energy technologies such as solar photovoltaic ("PV") generation.

Q. What is Vote Solar?

A. Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence, and fight climate change by making solar a mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local, and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. Vote Solar is not a trade group and does not have corporate members. Vote Solar has approximately 84,000 members nationally and 18,000 in California.

Q. By whom are you employed and in what capacity?

A. I am President and founder of New Energy Advisors, LLC, an independent consulting firm. At New Energy Advisors, I work with environmental and consumer advocates on a variety of clean energy issues and opportunities. In addition to this proceeding, I am currently supporting clients in Arizona, Minnesota, and North Carolina with various regulatory proceedings related to distributed energy resources ("DER").

Q. Please describe your professional background and experience.

A. I have 32 years of experience in the energy and utilities industries. Prior to founding New Energy Advisors, I worked for the Environmental Law & Policy Center ("ELPC") in Chicago as a Senior Clean Energy Specialist. My work at ELPC focused on providing technical advice and expert witness testimony in several renewable energy, energy efficiency, and rate design regulatory proceedings.

Prior to ELPC, I was employed for eighteen years by Accenture, a global management consulting and technology firm. I held several positions at Accenture, including Managing Director in Accenture's Sustainability Services practice, where I oversaw energy-related projects for municipal, commercial and industrial clients across multiple industries. I was also an Executive Director in Accenture's North America Utilities practice, with client account leadership responsibilities for several gas, electric, and water utilities in the US. In this role, I oversaw utility cost reduction and smart grid programs.

Prior to Accenture, I worked for the consulting firm UMS Group, where I led multi-utility benchmarking studies examining global best practices in electric transmission and distribution. Participating utilities were from the US, Canada, Australia, New Zealand, Europe, and Africa.

I also worked for nine years at Pacific Gas and Electric ("PG&E") in various transmission and distribution roles including Distribution Planning

Engineer, where I evaluated the impacts of cogeneration on distribution system protection and the impacts of demand-side management programs on the deferral of distribution substation upgrades.

Q. Please describe your educational background.

A. I graduated from the University of Illinois at Urbana-Champaign with a Bachelors of Science in Electrical Engineering and a concentration in Electrical Power Systems. I also received a Masters of Business Administration from the University of California at Berkeley with a concentration in Finance.

Q. Have you previously testified before the California Public Utilities Commission (the "Commission" or "CPUC")?

A. No. However, I have submitted comments on behalf of Vote Solar in the Commission's proceeding regarding policies, procedures and rules for development of Distribution Resources Plans ("DRP"), Rulemaking 14-08-013. I have also participated in the DRP Integration Capacity Analysis ("ICA") and Locational Net Benefits Analysis ("LNBA") Working Groups on behalf of Vote Solar.

Q. Have you previously testified before other regulatory commissions?

A. Yes. I have testified before:

- The Illinois Commerce Commission in its investigation into:
  - Commonwealth Edison's cost of service in Docket No. 14-0384.
  - Commonwealth Edison's proceeding for approval of its Energy Efficiency and Demand Response Plan in Docket No. 13-0495.
  - Ameren Illinois' proceeding for approval of its Energy Efficiency and Demand Response Plan in Docket No. 13-0498.
- The Michigan Public Service Commission in its investigation into the application of Consumers Energy Company to amend its renewable energy plan in Case No. U-17752.

- The Arizona Corporation Commission in its investigation of the value and cost of distributed generation in Docket No. E-00000J-14-0023.
- The Arkansas Public Service Commission in the matter of net metering and investigation of policies related to renewable distributed electric generation in Dockets 16-027-R and 16-028-U.

I have also submitted technical comments on behalf of my client in the Minnesota Public Utilities Commission investigation into Grid Modernization and Distribution Planning, Docket No. E999/CI-15-556.

2 Purpose of Testimony, Summary of Recommendations

Q. What is the purpose of your testimony in this proceeding?

A. My testimony serves two objectives. First, I will explain why the grid modernization investments proposed by Southern California Edison ("SCE" or "Company") are premature, excessive, and fail to provide net benefits to ratepayers. Second, I will explain how SCE is not taking full advantage of DER and third-party capabilities to minimize costs.

Q. Please summarize your conclusions and recommendations.

A. I conclude that SCE's forecast of residential PV growth is significantly higher than what market analysts expect in California in the 2017-2020 period. I also conclude that SCE is underestimating the positive and exaggerating the negative impacts of DER in its GRC application, resulting in:

- Proposed capital expenditures that are unnecessary at SCE's current and projected levels of DER penetration;
- An overstated need for capacity-related capital expenditures; and
- A proposed grid modernization program that is extremely costly and fails to deliver net benefits to ratepayers.

I recommend that the Commission:

1) Adopt ORA's recommendation[1] and disallow $1.66 billion[2] of SCE's 2018-2020 request to fund its grid modernization program and to only authorize distribution automation expenditures consistent with historical spending.

2) Disallow $875 million of 2018-2020 capacity-related costs[3] in this GRC application. Require SCE to develop new load forecasts using a revised PV Dependability curve based on cleaned-up data[4] and PV system output on circuit peak days, also considering the impacts of demand response ("DR") and energy storage, and to submit a new request for capacity-related projects for the Commission to review as part of this proceeding.

3) Require SCE to develop a new PV Dependability curve consistent with the recommendations of the Track 3, Sub-track 1 Working Group (or other proceeding) and consistent with the other California IOUs, and to use this new curve in all future distribution load forecasts and associated requests for capacity-related capital investments.

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[1] ORA Report on the Results of Operations for Southern California Edison Company General Rate Case Test Year 2018, Exhibit ORA-09, April 7, 2017, pp. 93, 114. ORA's recommendations include only 2018 Test Year amounts for this GRC period.

[2] SCE 02 Volume 10, pp. 60, 61, 73; SCE 02 Volume 10A, pp. 35, 39a, 40a. Includes 2018-2020 costs for Distribution Automation (WCR and DER-focused), Substation Automation (SA-3), Common Substation Platform (CSP), Field Area Network (FAN), Wide Area Network (WAN), Grid Management System (GMS). Excludes $6.2 million in 2018 for the System Modeling Tool (SMT) and DRP External Portal, which SEIA and Vote Solar support.

[3] SCE 02 Volume 03R, Table IV-14, p. 57. Includes 2018-2020 costs for Distribution Circuit Upgrades, New Distribution Circuits, Substation Expansion Projects, 4 kV Capacity Overload Cutovers, Subtransmission Lines Plan, Transmission Substation A-Bank Plan

[4] This includes eliminating from the data set the PV systems with integer-only output values, ignoring intervals with missing values due to CSI meters not recording properly, and eliminating systems with all zeros for the minimum.

4) Authorize SCE to proceed with a DER Management System ("DERMS") implementation and to deploy the minimum technology necessary to satisfy the new DER communication requirements of Rule 21 while fully leveraging the monitoring, communication and control capabilities inherent in most DER technologies.

5) Disallow SCE's 2018-2020 request for $129 million for subtransmission relay replacements, and only authorize expenditures for replacement of distance relays where SCE has conducted sufficient engineering analysis to demonstrate the potential risk of load encroachment over the 2018-2020 GRC period.

3 SCE's proposed grid modernization investments are premature

3.1 Components and costs of SCE's grid modernization program

Q. How has SCE rationalized the need for grid modernization?

A. Among other reasons, SCE cites Public Utilities Code Section 769 and the Commission's DRP proceeding aiming to create a "plug and play distribution grid" where high penetrations of DER can be integrated seamlessly, and to:

1) Modernize the electrical distribution system to accommodate two-way flows of energy services throughout the IOU's networks;
2) Enable customer choice of new technologies and services that reduce emissions and improve reliability in a cost efficient manner; and
3) Support opportunities for DER to realize benefits through the provision of grid services.[5]

[5] SCE 02 Volume 3, p. 3

Q. What are SCE's proposed grid modernization investments?

A. According to SCE-02 Volume 10 of SCE's GRC application, its proposed grid modernization investments include Distribution Automation, Substation Automation, a Common Substation Platform, Field Area Network, Wide Area Network, System Modeling Tool, DRP External Portal, and a Grid Management System. The total capital costs for these proposed investments are $1.9 billion from 2016-2020.[6]

Q. Are there other proposed investments in SCE's GRC Application related to grid modernization?

A. Yes. SCE proposes to make several information technology ("IT") capital investments including a Grid Interconnection Processing Tool, a Grid Analytics Application, Long Term Planning Tools, a Grid Connectivity Model, and Grid Modernization Cybersecurity. Total capital costs for these proposed IT investments are $161 million from 2016-2020.[7]

Additionally, SCE proposes to replace 588 subtransmission relays identified as potentially unreliable under the conditions of load encroachment caused by DER. The capital costs for the relay replacement are $129 million from 2018-2020.[8]

Q. What is the total cost of SCE's proposed grid modernization investments?

A. Including all the categories of expenditures above, the total cost is $2.2 billion from 2016-2020 in nominal dollars. But this is just the tip of the iceberg. SCE has indicated that due to the size of its system, deploying the proposed technology will take 10 years to cover 60% of SCE's total urban

[6] SCE 02 Volume 10A, p. 35

[7] WP SCE 04 Vol. 2, Table III-8, Tables V44-V47. SCE is also proposing to add $44.54 million of incremental O&M in 2018-2020 for IT associated with grid modernization.

[8] SCE 02 Volume 6, p. 37, Table I-15

distribution circuits."[9] The total cost to modernize SCE's grid using its proposed approach could exceed $7.5 billion.[10]

3.2 Other related proceedings

Q. Why are SCE's proposed grid modernization investments premature?

A. There are many unanswered questions regarding grid modernization and appropriate utility investments to enable DER growth. The Commission is addressing many of these questions in other parallel proceedings, yet SCE has jumped the gun. For example:

- DRP Track 1 – Continued work on Demo A (ICA) and Demo B (LNBA) will establish tools for determining optimal DER locations to minimize costs. SCE's methodology in its GRC application for determining optimal DER locations and prioritizing grid modernization investments[11] does not utilize the ICA and is inconsistent with the LNBA.[12]
- DRP Track 2 – The utilities have been ordered to evaluate the relative cost-effectiveness of utility owned vs. third-party owned communications infrastructure for managing DER.[13] In this GRC, SCE proposes a $218 million[14] investment in utility-owned grid and DER communications and

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[9] SCE response to ORA-SCE-203-TCR Question 08 (all non-spreadsheet responses to data requests cited in this testimony are contained in Appendix A)

[10] $7.5 billion cost estimate provided by TURN during the January 24, 2017 CPUC Grid Modernization Investment Framework Workshop

[11] SCE 02 Volume 10, Workpaper "Distribution Automation & Circuit Tie Deployment Plan"

[12] SCE response to ORA-SCE-031-TCR Question 13

[13] Decision 17-02-007, Decision On Track 2 Demonstration Projects, February 16, 2017, p. 28

[14] 2018-2020 costs for the Field Area Network and maintaining the existing NetComm system, nominal dollars, see SCE 02 Vol. 10, p. 73, Figure III-24 and SCE 02 Vol. 10, p. 74, Figure III-25

control infrastructure prior to the completion of its Track 2 demonstration projects.

- DRP Track 3, Sub-track 1 – The DER Growth Scenarios and Distribution Load Forecasting Working Group will develop the methodology and assumptions for DER adoption scenarios, and develop approaches to disaggregate forecasts to the circuit level.[15] As I will explain later, there are fundamental differences in the way the California IOUs incorporate DER into their load forecasts, which can significantly impact capacity-related capital investment. As much as $875 million of 2018-2020 capital in its GRC application is influenced by SCE's methodology for incorporating DER in load forecasting, and I believe SCE's methodology is fundamentally flawed.
- DRP Track 3, Sub-track 2 – In the Grid Modernization Investments sub-track, the parties will consider what grid modernization functions need to be deployed to support full DER integration. As a result of this sub-track, the Commission will develop guidelines to govern utilities' future requests for funding related to grid modernization.[16] Approval of SCE's proposed grid modernization investments prior to the development of these guidelines may lead to redundancy and stranded costs.

3.3 SCE's DER penetration levels

Q. Has SCE provided a forecast of expected residential PV installations?

A. Yes. SCE explains:

> SCE utilizes a generalized bass diffusion process to model residential customer adoption of solar PV systems. The

[15] Rulemaking 14-08-013, Assigned Commissioner's Ruling Setting Schedule for Submission of Distributed Energy Resource Growth Scenarios and Distribution Load Forecasting, 2/27/17, p. 3

[16] Rulemaking 14-08-013, Assigned Commissioner's Ruling on Track 3 Issues, 8/9/2016, p. 4

> model utilizes the solar PV system costs adjusted for the federal Investment Tax Credit as an explanatory variable. SCE fits the model with the historical customer adoption data (up to the end of 2015) and uses it to predict future customer adoption over the SCE service territory. In addition, SCE takes into consideration of [sic] the impacts from the recent tier rate changes and California's Zero Net Energy (ZNE) mandate … This solar PV forecast is then adapted for allocation down to the circuit level for distribution planning analysis purposes.[17]

Q. Is SCE's forecast consistent with other residential PV forecasts you've seen for California?

A. No. As shown below, the 2016 SEIA/Greentech Media U.S. Solar Market Insight ("SMI") report[18] projects a much lower growth rate for residential PV in California from 2017-2020.

	SCE's Cumulative MW[19]	SCE's Incremental MW	SCE Growth Rate	SMI CA Growth Rate
2015	791			
2016	1,172	381		
2017	1,658	486	28%	(5%)
2018	2,214	556	14%	3%
2019	2,811	597	7%	5%
2020	3,434	623	4%	9%

Residential PV Installation Forecasts

Q. Why does SEIA/Greentech Media expect a slowdown in the residential PV growth rate in California?

A. The SMI report explains:

> Two fundamental changes that began to impact the market in 2016 will continue into 2017: the gradual shift to time-of-use rates in the NEM 2.0 environment, and an evolving

[17] SCE 09 Volume 1, p. 66

[18] U.S. Solar Market Insight 2016 Year in Review ("SMI Report"), p. 52, available at https://www.greentechmedia.com/research/subscription/u.s.-solar-market-insight

[19] SCE 09 Volume 1, p. 67

> and maturing customer landscape that requires a more efficient sales and customer acquisition process to reach customers beyond early adopters … Sales teams are encountering a growing sense of customer fatigue and correspondingly protracted lead-generation and sales timelines. These timelines are not expected to decrease in the NEM 2.0 environment in 2017 as the sales conversation becomes more complex with the introduction of TOU rates and the corresponding challenge of modeling potential savings for customers … California is not expected to surpass double-digit growth again until 2022, once residential solar-plus-storage economics substantially improve.[20]

Q. What are the implications of this?

A. SCE is proposing investments to accommodate levels of DER penetration much higher than it is currently experiencing and is projected to experience in this 2018-2020 GRC timeframe.

Q. Please provide examples of this.

Much of SCE's rationale for grid modernization investments is related to potential complications from reverse power flow from DER. SCE's calculations used in its benefit-cost analysis show that 790 of its 4,636 circuits[21] have the potential for reverse power flow in the 2018-2020 GRC period.[22] I will explain later how SCE is significantly overstating the likelihood of reverse power flow in its analysis.

As I mentioned previously, SCE is proposing to replace 588 subtransmission relays identified as potentially unreliable under the

[20] SMI Report, pp. 17-18

[21] SCE 02 Volume 1, p. 2

[22] See cell B4 in the tab "DER Reliability Impact" of the spreadsheet entitled "s7.6 DER Impact on Reliability_Rev1.xlsx" provided in response to SEIA-Vote Solar Question 7.6 (A Notice of Availability, served concurrently with this testimony, provides access to all cited spreadsheets)

conditions of load encroachment caused by DER at a cost of $129 million from 2018-2020.

SCE explains:

> SCE developed a system-level forecast of DER installations through 2020, and allocated these installations, and their associated capacities, across SCE's distribution circuits for each of the years 2015 – 2024 … In parallel with this effort, SCE reviewed all subtransmission circuit relays and identified the relays not designed for, or expected to operate under, the conditions of load encroachment. Combining these studies, SCE then identified which of those vulnerable relays were forecast to experience reversed power flow prior to the end of 2020 based on the latest circuit DER Forecast. Those vulnerable relays are the relays SCE intends to replace with relays capable of operating dependably under the conditions of load encroachment. Relay replacement will be prioritized based on when each relay is expected to encounter load encroachment.[23]

And also:

> Legacy electromechanical and solid state ***distance relays*** must be replaced with intelligent microprocessor relays with load encroachment functionality on the transmission system.[24]

Load encroachment can occur with increased line load, which may be attributable to reverse power flow. The increased load may exceed the relay's settings causing the relay to operate incorrectly.[25] The presence of reverse power flow does not necessarily lead to load encroachment and, as SCE indicates above, load encroachment is an issue specific to one type of relay called a distance relay.

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[23] SCE 02 Volume 6, p. 33

[24] SCE 02 Volume 6, Workpaper "Integrated Distributed Energy Resources & Protection System Upgrades", p. 7 (emphasis added)

[25] Load encroachment and steps to address it are further explained by the paper "Calculating Loadability Limits of Distance Relays", available at http://www.cce.umn.edu/documents/cpe-conferences/mipsycon-papers/2012/calculatingloadabilitylimitsofdistancerelays.pdf

In response to our data request, SCE provided a list of all relays targeted for replacement under this program, including age and relay type. Only 111 of 1,043 relays on the list are distance relays, with another 22 relays labeled as "Both" (meaning distance and overcurrent relaying functionality).[26] We asked SCE for the DER penetration levels and year at which there will be sufficient reverse power flow to potentially cause load encroachment for each relay. In response to a SEIA-Vote Solar data request SCE stated, "SCE cannot accurately predict when this will occur unless a detailed engineering study was performed of each relay."[27]

Additionally, 90% of the relays were missing ages in SCE's response and it's fair to assume that these are among the oldest, as they would pre-date modern asset management practices. Rather than attribute the need for relay replacement to DER, it's more appropriate to replace these relays over time under SCE's Substation Protection and Control Replacements program.

Q. What do you conclude?

A. I conclude that SCE's request for approval to replace 588 relays is premature, as it hasn't conducted the engineering analysis to confirm that the risk of load encroachment is real. The request may also be significantly overstated if there are only 133 distance relays on the list targeted for replacement.

Q. What do you recommend?

A. I recommend that the Commission disallow SCE's 2018-2020 request for $129 million for subtransmission relay replacements, and only authorize expenditures for replacement of distance relays where SCE has conducted sufficient engineering analysis to demonstrate the potential risk of load encroachment over the 2018-2020 GRC period.

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[26] See spreadsheet entitled "SEIA 003 Q3.1.xlsx"

[27] SCE response to SEIA-Vote Solar Question 3.1

3.4 SCE's service territory compared to Hawaii

Q. SCE cites the example of Hawaii, where proliferation of PV and failure to proactively upgrade the grid led to interconnection delays, grid operational issues, and widespread customer frustration.[28] Is SCE's service territory in a similar situation as Hawaii?

A. No. The table below shows that, as of 12/31/2016, the penetration of NEM PV installations in SCE's service territory (measured as a percentage of peak demand) is significantly less than Hawaii.

Company	Peak Demand (MW)	Installed NEM PV (MW)	NEM % of Peak Demand
Hawaiian Electric Co. (Oahu)	1,214[29]	299.2[30]	25%
Maui Electric Company	205.4[31]	80.0[20]	39%
Hawaii Electric Light	188.5[32]	69.6[20]	37%
SCE (12/31/2016)	22,224[33]	1,714.1[34]	7.7%

My understanding is that the interconnection delays and customer frustration in Hawaii were largely caused by the utilities' lack of knowledge of how much PV hosting capacity was actually available across their systems. The ICA and associated transparency of hosting capacity for each circuit location should prevent these issues from occurring for SCE's customers.

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[28] SCE 01, pp. 13-14

[29] https://puc.hawaii.gov/wp-content/uploads/2015/04/2017-HECO-AOS-Report.pdf

[30] https://puc.hawaii.gov/wp-content/uploads/2013/07/2016-HECO-NEM-Status-Report.pdf

[31] https://puc.hawaii.gov/wp-content/uploads/2015/04/2017-MECO-AOS-Report.pdf

[32] https://puc.hawaii.gov/wp-content/uploads/2015/04/2017-HELCO-AOS-Report-.pdf

[33] http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN215745_20170202T125433_FINAL_California_Energy_Demand_Updated_Forecast_20172027.pdf, p. 31

[34] SCE Advice Letter 3544-E (submitted January 10, 2017)

4 SCE's proposed Grid Modernization costs are excessive

Q. Please provide a high level description of SCE's distribution system design.

A. SCE's distribution system is generally designed as a radial system with normally open circuit ties to neighboring circuits. Each circuit is typically configured with switches to sectionalize and isolate circuit segments, as well as to allow for load transfers to neighboring circuits.[35]

Q. Has SCE previously automated its distribution circuits and substations?

A. SCE has been automating its circuits and substations since the late 1990s.[36] Its existing automation scheme is designed with one Remote Controlled Switch ("RCS") installed with 30-70% of the circuit's load downstream ("mid-point switch") to one normally open RCS tied to a neighboring circuit ("circuit-tie switch"). SCE calls this configuration a "1.5 scheme".[37] About three-quarters of SCE's circuits have some level of automation today.[38]

Q. Has SCE's previous automation of its circuits and substations resulted in improved reliability?

A. Yes. As SCE explains (where System Average Interruption Duration Index or "SAIDI" is the average minutes of outage time per customer per year):

> Historical implementation of automation has proven to be effective. In 2009, SCE automated 360 distribution circuits. The average SAIDI for these circuits over the period 2006 – 2008 was 180.3 minutes prior to

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[35] SCE 02 Volume 10, Workpaper "Distribution Automation and Circuit Tie Design Criteria", p. 103

[36] SCE 02 Volume 10, p. 42

[37] SCE 02 Volume 10, Workpaper "Distribution Automation and Circuit Tie Design Criteria", p. 103

[38] SCE 02 Volume 10, p. 35

> automation. After automation, the average SAIDI for these circuits over the period 2010-2012 was 166.5 minutes, a reduction of 8%. In 2010, SCE automated 321 distribution circuits. The average SAIDI for these circuits over the period 2007 – 2009, prior to automation, was 166.7 minutes. After automation, the average SAIDI for these circuits over the period 2011 – 2013 was 149.4 minutes, a reduction of 10%.[39]

Q. What is SCE's proposed advanced automation approach?

A. SCE's proposed advanced automation approach includes:

- Remote Intelligent Switches, which measure and communicate circuit parameters such as voltage and current and can operate automatically;
- Remote Fault Indicators, which detect faults, indicate fault direction, measure and communicate circuit parameters;
- Remote Controlled Switch Retrofits, which involve retrofitting existing switches to measure and communicate circuit parameters;
- Circuit Tie Switches, to increase capabilities to transfer load between circuits
- Associated telemetry, communications, and software.

The approach will typically equip each distribution circuit with up to three mid-point switches and up to three circuit-tie switches, and provide real-time information to operators on system conditions.[40]

Q. What are SCE's expected results from this approach?

A. SCE states:

> The modernized distribution automation system will be able to provide real-time information on the distribution system to allow system operators to quickly take action to mitigate conditions such as those created by higher levels of DER, possible equipment thermal overload issues, or overvoltage conditions. This results in improved reliability by enabling the distribution system to identify fault location, isolate the fault, and restore power automously [sic] at a faster response

[39] *Id.*, pp. 33-34

[40] SCE 02 Volume 10, Workpaper "Distribution Automation and Circuit Tie Design Criteria", p. 107

> rate than can be done today. The information provided by this modern automation system will allow the system operators to determine the instantaneous current, voltage, and power flow at each automated switch. It will allow the operators to know the current and power direction at every remote fault indicator on the circuit and determine the instantaneous load at those locations on the circuit with an accuracy of ±5%.[41]

Q. What would this advanced automation approach cost SCE's ratepayers?

A. SCE has proposed to automate 600 Worst Circuit Rehabilitation ("WCR") circuits and 263 "DER Driven" circuits (863 circuits total) at a nominal cost of $862 million from 2018-2020.[42] That's $1 million per circuit.

If you include the costs for the associated substation automation, common substation platform, field area network, wide area network, and grid management system that SCE says is necessary to realize the full benefits of advanced automation, the 2018-2020 nominal cost is $1.68 billion.[43]

The present value of revenue requirements for SCE's proposed advanced automation in this GRC is $2.8 billion, according to SCE's calculations.[44] If you include conductor upgrades that SCE proposes to further improve reliability, the present value of revenue requirements increases to $3.1 billion.[45] This is for only 863 of SCE's 4,636 circuits. As I previously mentioned, this is just the first installment on a much larger and longer-term investment in grid modernization.

Q. Have other utilities applied this advanced approach to automation?

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[41] *Id*.

[42] SCE 02 Volume 10A, pp. 39a-40a

[43] *Id*., pp. 35, 39a, 40a; SCE 02 Volume 10, pp. 60-61, 73-74

[44] See cell D66 in the tab "2. BCR & PVRR Calcs" of the spreadsheet entitled "SCE reliability technology BCA.xlsx" provided in SCE's response to TURN-SCE-026 Question 55

[45] *Id*., cell D67

A. I am not aware of another utility that has implemented or has proposed to implement this 3 mid-point and 3 circuit-tie switch automation approach. We asked in a data request if SCE could name another utility that has implemented a similar approach and it could not.[46]

Q. Are there other, more cost effective approaches that could deliver similar benefits?

ORA witness Tom Roberts has determined that SCE could achieve 79% of the proposed reduction in SAIDI by implementing its traditional "1.5 scheme"[47] at a fraction of the cost.[48]

Q. What do you recommend?

A. I agree with the recommendation of ORA to disallow $1.66 billion of SCE's 2018-2020 request to fund its grid modernization program and to only authorize distribution automation expenditures consistent with historical spending.[49]

5 SCE's proposed grid modernization investments do not provide net benefits to ratepayers

5.1 Description of SCE's benefit cost analysis (BCA)

Q. Does SCE have an obligation to demonstrate net benefits for ratepayers from its grid modernization investments?

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[46] SCE response to SEIA-Vote Solar Question 1.32

[47] As previously defined, SCE's "1.5 scheme" is its historical approach to automation with one midpoint switch and one circuit tie switch.

[48] ORA Report on the Results of Operations for Southern California Edison Company General Rate Case Test Year 2018, Exhibit ORA-09, April 7, 2017, pp. 106-107

[49] *Id.*, pp. 93, 114

A. Yes. The grid modernization investments proposed by SCE in this rate case are from its Distribution Resources Plan, filed pursuant to Section 769 of the California Public Utilities Code. Section 769 5(d) requires that "Any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation. The commission may approve proposed spending if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable."[50]

Q. Has SCE successfully demonstrated that ratepayers would realize net benefits from its proposed grid modernization benefits?

A. No. While SCE provided a benefit-cost analysis ("BCA") for its proposed grid modernization investments related to Distribution Automation ("DA"), circuit tie switches, Grid Management System ("GMS"), and the enabling foundational investments in the Field Area Network ("FAN"), Wide Area Network ("WAN"), and Common Substation Platform[51], it has not successfully demonstrated that its proposed investments provide net benefits to ratepayers. SCE has only quantified reliability benefits in its BCA and explains:

> Additional benefits lie in the areas of: (1) operability and accuracy of circuit parameter information provided to operators; and (2) realizing DER benefits. While the value of these non-reliability benefits have not yet been quantified, the value of the reliability benefits (which have been quantified) alone demonstrate the importance of the proposed Distribution Automation program and its three mid-point three tie switch design to the ratepayer.[52]

Q. What is SCE's approach to quantifying reliability benefits in the BCA?

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[50] California Public Utilities Code Section 769 5(d)

[51] See the spreadsheet entitled "SCE reliability technology BCA.xlsx"

[52] SCE's response to SEIA-Vote Solar Question 1.31

SCE considers four grid modernization scenarios in its BCA:

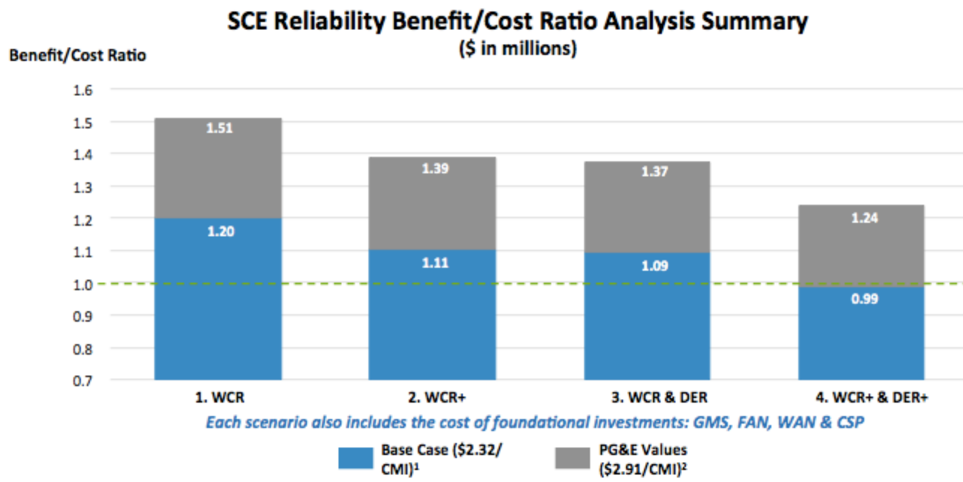
1) Automating 200 of its Worst Circuit Rehabilitation ("WCR") circuits per year (called the WCR scenario);
2) Automating 200 WCR circuits per year plus conductor upgrades (WCR+);
3) Automating 200 WCR circuits per year and 88 circuits per year where SCE expects high penetrations of DER (WCR & DER); and
4) Automating the same circuits as 3) plus conductor upgrades (WCR+ & DER+).

SCE calculates all of the benefits using values for avoided Customer Minutes of Interruption ("CMI") and avoided momentary interruptions. The Company uses an initial value of $2.32 per avoided CMI and $91.05 per avoided momentary interruption in 2016, and escalates the values at a rate of approximately 2% per year through 2046. SCE references a customer interruption cost study conducted by PG&E in 2012 that values avoided outages for customers in PG&E's service territory at $2.91 per CMI and $114.10 per avoided momentary interruption. SCE calculates benefits using these higher PG&E values in its BCA and shows the results using both sets of outage cost estimates.

SCE estimates the avoided momentary interruptions and CMI from its various proposed grid modernization investments due to remote switching, faster fault locating, assisted and automated decision making and "***avoided DER impairment***". Multiplying the estimated avoided outages by the cost per avoided CMI and momentary interruption results in the reliability benefits in the BCA.

Q. How has SCE presented the BCA results?

A. SCE converts the costs of the various programs to a revenue requirement, calculates the present value of costs and benefits from 2018-2045, and calculates the benefit/cost ratio for each grid modernization scenario. The results are shown below (copied from SCE's BCA spreadsheet), with values above 1.0 indicating net benefits for ratepayers. Note that investments beyond the first scenario of automating 200 WCR circuits negatively impact the BCA.



Q. Do you agree with this approach?

A. No. I am skeptical that SCE's outage cost calculations accurately reflect the value of reliability for SCE customers. I also disagree with the concept of "avoided DER impairment".

5.2 <u>Outage costs, reverse power flow, and "avoided DER impairment"</u>

Q. How has SCE determined its customers' outage costs?

A. In response to our data request SCE stated, "The average cost per CMI … was calculated by Nexant, Inc. whom we believe to be the leading expert in this field. Nexant has not made available to SCE all the details and methods of its analysis."[53]

As Nexant explains in one of SCE's workpapers:

[53] SCE's response to SEIA-Vote Solar Question 1.35

> The preferred method for estimating customer interruption costs is a survey that describes several hypothetical interruption scenarios and asks customers to detail the costs that they would experience under those conditions … customer surveys are the preferred method for estimating customer interruption costs because they directly measure the costs that customers experience under a variety of interruption scenarios without relying on the relatively weak assumptions that alternative methods use. The primary drawback of surveys is that they require collecting detailed information from large, representative samples of residential, commercial, and industrial (C&I) customers. As a result, only a few of the largest utilities in the U.S. have conducted customer interruption cost surveys. [54]

SCE has not conducted its own customer interruption cost survey and the $2.32 per CMI and $91.05 per avoided momentary interruption are derived by Nexant using a Lawrence Berkeley National Laboratory ("LBNL") nationwide study and PG&E's 2012 customer interruption cost survey.

Q. Do you agree with this approach?

A. After repeated requests for details of the calculations supporting the $2.32, we had a call with Nexant on April 10, 2017 to discuss the analysis. On the call, Nexant agreed to provide a spreadsheet with additional details of the calculations, which we received on April 19, 2017. This spreadsheet lacked sufficient detail and we had a second call with Nexant on April 24, 2017, during which Nexant agreed to revise the spreadsheet to provide full transparency and clarity of the calculations. We received the second spreadsheet on April 28, 2017 and, although I now understand the mechanics of Nexant's calculations, I have concerns about the underlying data used in the analysis.

Q. What concerns do you have about the data?

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[54] SCE 02 Volume 10, Workpaper "Southern California Edison Customer Interruption Cost Analysis"

A. On the April 24 call, SCE informed me that the underlying outage data Nexant used in the calculation of the $2.32 was available in response to a TURN data request.[55] I reviewed the outage data and discovered a significant outlier. One outage (Chestnut circuit on July 15, 2015) accounts for 10% of the 2015 customer outage costs in the Nexant analysis. The Chestnut outage record shows 2,295 Medium-Large Commercial and Industrial ("C&I") customers and 1,530 Small C&I customers (3,825 customers total) interrupted for 3,035 minutes with an estimated customer outage cost of $100.2 million.[56] The outage record shows zero residential customers impacted.

Q. Is this customer count consistent with SCE's records for the Chestnut circuit?

A. No. The same spreadsheet indicates that the Chestnut circuit has only 4 Small C&I customers and 6 Medium-Large C&I customers.[57]

Q. Are you familiar with this outage?

A. I know there were significant outages in Long Beach starting July 15, 2015 with tens of thousands of customers impacted, and Chestnut was likely one of the circuits affected. I also know the Commission's Safety and Enforcement Division's ("SED") investigation report concluded that the outages primarily affected 3,825 customers[58], which matches SCE's customer count in the outage record.

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[55] See the spreadsheet entitled "TURN-SCE-085 Q.05 Supplemental Attachment.xlsx" provided in SCE's response to TURN-SCE-085 Question 5 Supplemental

[56] *Id.*, see row 62587 in the tab "Sustained Data"

[57] *Id.*, see rows 2267-2268 in the tab "Voltage and Customer Class Data"

[58] See "Investigation Report of Outages During July and August of 2015 in Southern California Edison Company's Long Beach District, June, 2016, p. 3, available at https://assets.documentcloud.org/documents/2995746/Investigation-into-Long-Beach-outages.pdf

Q. Does the SED report indicate that only C&I customers were affected by this outage?

A. No. The report doesn't specifically indicate how many customers by type were affected, but does state, "Although the outages at times extended to tens of thousands of customers, these periods of large outages were transient in nature. However, for a core of around 3,800 business and residential customers, many of whom were elderly or low income, the outages were lengthy, uncomfortable, costly, and potentially dangerous."[59]

Q. What are the implications of Nexant categorizing all 3,825 customers as C&I in its calculations?

A. In the Nexant analysis, outage costs for C&I customers are orders of magnitude greater than for residential customers.[60] By assuming that the 3,825 customers affected by this outage were all non-residential C&I customers, Nexant's calculations significantly overstate the outage costs for this event.

This raises questions about Nexant's methodology and how it has applied the LBNL and PG&E outage cost data to SCE's actual outage history. There may be other errors in the outage records but, since I only learned of the availability of this outage data on April 24 and received the details on Nexant's calculations on April 28, I didn't have time to examine it in detail or submit data requests to SCE for clarification.

To determine the sensitivity of the BCA to this error, I removed the one outlier Chestnut outage record from the data set, applied the same methodology as SCE and Nexant, and calculated an SCE cost per CMI of $2.25 (decreasing from $2.32).

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[59] *Id.*, p. 4

[60] The average cost per CMI is between $29.20-$48.99 for Medium and Large C&I, between $7.48-$12.55 for Small C&I, and between $0.05-$0.08 for residential customers, according to SCE's response to TURN-SCE-052 Question 09.b.

Q. Are you saying $2.25 per CMI is the correct value of outage costs for SCE's customers?

A. No. I'm saying it's a better number than $2.32 because it excludes the erroneous Chestnut outage record. If there are other errors in the outage data similar to the Chestnut outage record, the correct number could be much less than $2.25. Also, as I've stated previously, the data used by Nexant does not reflect SCE's customers' actual outage costs but is derived from the LBNL nationwide study and PG&E's 2012 customer interruption cost survey.

Q. Why else do you disagree with SCE's BCA approach?

A. I disagree with the concept of "avoided DER impairment". SCE describes this as "avoided CMI increase resulting from DER adoption" in the BCA and attributes a savings of 20 million CMI per year to this phenomenon. At $2.32 per CMI, it is contributing $46.4 million (in 2016 dollars) of benefits per year for 25 years to the BCA.

In response to SEIA-Vote Solar's request for further clarification on the concept of "avoided DER impairment", SCE directed us to a spreadsheet entitled "S-55-9 DER Impact on Reliability.xlsx".[61] The spreadsheet further reveals SCE's definition of "DER impairment" – it is the alleged increased CMI from additional pre-restoration engineering time required to review switching procedures on circuits with reverse power flow from DER. SCE assumes an additional 20 minutes for what they call a "state estimate" analysis for each outage event.

Put simply, SCE assumes a seemingly arbitrary 20-minute delay in restoration per outage event for all circuits with the potential for reverse power flow from DER ("DER impairment"). SCE is implying that the

[61] SCE response to SEIA-Vote Solar Question 5.7

availability of real-time information from its advanced automation will eliminate this delay and result in "avoided DER impairment".

Q. Do you agree with this analysis?

A. No. I disagree with the logic and the way SCE is calculating the potential for reverse power flow. I believe an arbitrary 20 minutes for a "state estimate" analysis per outage event is exaggerated and unlikely to occur. All grid-tied PV inverters are required to disconnect from the grid during an outage and the need for extended engineering review of switching procedures is minimal. As I will mention later, SCE's implementation of a DERMS will assist with safe reconnection of DER during service restoration and further eliminate the need for manual "state estimate" analyses. The alleged benefits from "avoided DER impairment" should be excluded from the BCA calculations.

Q. How has SCE identified circuits with the potential for reverse power flow?

SCE has identified 790 circuits[62] that could experience reverse power flow by 2020. The Company determined this by comparing each circuit's minimum load with the adjusted output from forecasted PV, 100% of nameplate output from forecasted combined heat and power ("CHP") systems[63], and full nameplate ratings of forecasted energy storage ("ES") systems. If the sum of the adjusted PV, CHP and ES output in 2020 exceeds a circuit's minimum load, SCE identifies the circuit as having reverse power flow.

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[62] See cell B4 in the tab "DER Reliability Impact" of the spreadsheet entitled "s7.6 DER Impact on Reliability_Rev1.xlsx" provided in response to SEIA-Vote Solar Question 7.6

[63] SCE 02 Volume 3R, Book A, Workpaper "DER Driven Circuit Upgrades Methodology", p. 151

Q. Why does SCE include CHP and energy storage in its calculations of reverse power flow?

A. In response to our data request, SCE stated:

> CHP and energy storage systems can contribute to reverse flow when an installer elects to discharge during off-peak and/or minimum load hours. SCE believes that in the absence of discharge/charge restrictions, it is prudent to assume a worst-case scenario to ensure circuitry is not adversely impacted due to the discharging of CHP and/or energy storage.[64]

Q. Do you agree with these assumptions?

A. No. I'm not sure what SCE means by "discharging of CHP", but many CHP systems are sized to match electrical loads at the customer site, with minimal exports to the distribution system. Storage systems will typically be charging, not discharging, during off-peak hours when electricity is cheaper. I believe SCE's inclusion of 100% of CHP nameplate output and 100% of energy storage nameplate capacity, and assuming it's fully discharging at the time of a circuit's minimum load, is counterintuitive and overly conservative.

Q. What are the implications of this?

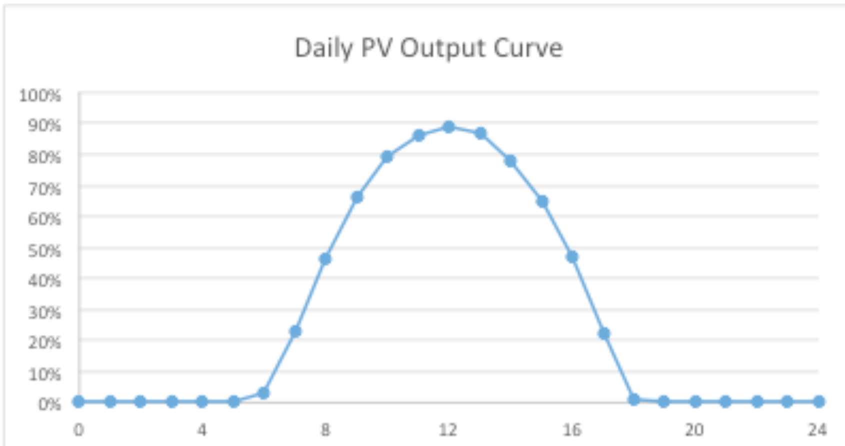
A. Removing the contributions of CHP and energy storage from the calculations decreases the number of circuits with reverse power flow in 2020 from 790 to 715, using SCE's calculations.

Q. How does SCE adjust output from forecasted PV?

A. SCE began with its 2016-2020 forecast of PV and other DER disaggregated to the feeder level. As I explained earlier, SCE's forecast of PV growth is significantly higher than what market analysts expect in California in the 2018-2020 period.

[64] SCE response to SEIA-Vote Solar Question 7.5

SCE applies the PV output curve below to adjust the nameplate rating based on the time of a circuit's minimum load. If, for example, a circuit with 1 MW of PV has a minimum load occurring at 9:00 am, then the adjusted PV used in the reverse power flow analysis is approximately 660 kW.[65]



SCE's PV Output Curve used for Reverse Power Flow Analysis

Q. How does SCE determine a circuit's minimum load?

A. In response to our data request, SCE stated:

> SCE conducted statistical analysis using the percentile method to determine minimum load. This analysis showed the minimum load hour to be midnight for a large number of feeders, as expected. Since the resources and tools necessary to conduct 8760 analyses on every such feeder were not available, SCE assumed that the PV output during daytime minimum load for such feeders to be 50% (typically occurring around 8 AM) to study the impact of PV during early day hours.[66]

Q. What does this mean?

A. It means that for all circuits with minimum load occurring during the nighttime hours, SCE assumes the daytime minimum load occurs "around

[65] SCE 02 Volume 3R, Book A, Workpaper "DER Driven Circuit Upgrades Methodology", pp. 150-151

[66] SCE response to SEIA-Vote Solar Question 7.1.d

8:00 am" and applies a 50% adjustment factor to PV output. SCE makes this adjustment to 3,728 of its circuits.

However, the formula that SCE uses in its spreadsheet not only adjusts the factor to 50% for circuits with nighttime minimum loads, but incorrectly includes circuits with minimum loads between 6:00-8:00 am and 4:00-6:00 pm[67] (341 circuits total). Correcting this formula reduces the number of circuits with reverse power flow from 715 to 698 using SCE's calculations.

Q. Do you agree with SCE's assumption that the daytime minimum occurs at "around 8am" for these circuits?

A. It depends on the type of customers served by each circuit. For circuits with many C&I customers operating seven days a week, the daytime minimum may occur earlier than 8:00 am before employees show up for work and businesses begin to operate.

SCE's analysis is very sensitive to this assumption. SCE's PV Output Curve reflects 46% at 8:00 am, not 50%. By reducing the PV adjustment factor to 46% in SCE's calculations, the number of circuits with reverse power flow further decreases from 698 to 655. If you assume the daytime minimum occurs at 7:00 am, when PV output is at 23% according to SCE's curve, the number of circuits with reverse power flow decreases from 655 to 507, again using SCE's calculations.

Q. Has SCE's "statistical analysis using the percentile method" resulted in circuits with minimum loads occurring during business hours?

Y. SCE's analysis using this method results in 857 circuits with minimum loads occurring between 8:00 am and 5:00 pm, as shown below.

[67] See the formulas in column Q in the tab "Min Load and PV Adj" of the spreadsheet entitled "s7.6 DER Impact on Reliability_Rev1.xlsx" provided in response to SEIA-Vote Solar Question 7.6

Time of minimum load	# of SCE circuits
8:00 am	154
9:00	56
10:00	45
11:00	81
12:00 pm	170
1:00	171
2:00	111
3:00	31
4:00	21
5:00	17

Q. Does this seem correct?

A. I can understand how residential circuits could have minimum loads during daytime hours as these customers are often away from their homes and using minimal amounts of electricity during the day. It's difficult for me to understand how circuits with higher percentages of small, medium and large C&I customers could experience minimum loads during normal business hours.

Q. Do any circuits with significant percentages of C&I customers have minimum loads during business hours according to SCE's method?

A. Yes. 103 of the circuits that SCE has identified with reverse power flow have at least 25% C&I customers and minimum loads between 8:00 am and 5:00 pm. To provide two examples, circuit Pinon has 326 small C&I and 41 medium-large C&I customers (no residential)[68], and SCE says the minimum load occurs at 11:00 am.[69] Circuit Mescal has 1 residential customer, 86

[68] See rows 8465-8466 in the tab "Voltage and Customer Class Data" of the spreadsheet entitled "TURN-SCE-085 Q.05 Supplemental Attachment.xlsx"

[69] See cell D3069 in the tab "Min Load and PV Adj" of the spreadsheet entitled "s7.6 DER Impact on Reliability_Rev1.xlsx"

small C&I and 45 medium-large C&I customers[70] and SCE says the minimum load occurs at 1:00 pm.[71]

We asked SCE to confirm that such a large number of circuits with minimum loads during the day was correct, to which they responded "These values are correct, based on statistical analysis (percentile method) … It is important to note that SCE customer mix and load characteristics are inherently diverse, and that minimum loading on some feeders may occur during the middle of the day."[72] I will be following-up with additional data requests to further clarify this.

Q. What are the implications of this?

A. By beginning with a PV forecast that is significantly higher than what market analysts project, using the "statistical analysis (percentile method)" to set minimum loads during daytime (and high PV production) hours for so many circuits with non-residential customers, including CHP and energy storage, and assuming an 8:00 am daytime minimum for the majority of its circuits, I believe SCE is significantly overstating the number of circuits with reverse power flow by 2020.

Q. What do you recommend?

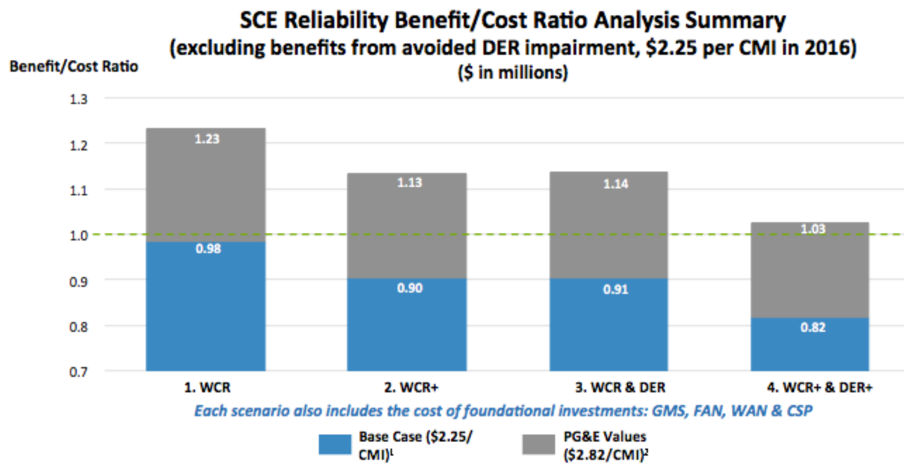
A. Even if SCE had calculated the reverse power flow values correctly, the alleged benefits from "avoided DER impairment" should be excluded from the analysis. This, combined with an updated value for SCE customers' outage costs, significantly changes the BCA. See below for the modified BCA analysis using an initial value of $2.25 per CMI in 2016 and excluding the 20 million CMI savings per year from "avoided DER impairment". The

[70] See rows 7140-7142 in the tab "Voltage and Customer Class Data" of the spreadsheet entitled "TURN-SCE-085 Q.05 Supplemental Attachment.xlsx"

[71] See cell D2592 in the tab "Min Load and PV Adj" of the spreadsheet entitled "s7.6 DER Impact on Reliability_Rev1.xlsx"

[72] SCE response to SEIA-Vote Solar Question 7.3

benefit/cost ratios are all less than 1.0 and none of the grid modernization investment scenarios provide net benefits to ratepayers.



SCE's proposed grid modernization expenditures are premature, excessively costly, and fail to provide net benefits to ratepayers. As I stated previously, I support ORA's recommendation to reject SCE's request to fund its advanced automation program and to only authorize distribution automation expenditures consistent with historical spending.

6 SCE's approach to this GRC does not fully reflect the contributions and capabilities of DER and third-party providers to minimize costs

6.1 PV Dependability

Q. Why do you believe SCE's approach does not fully reflect contributions from DER to minimize costs?

A. I will provide several examples, but the most egregious is SCE's application of what it calls PV Dependability. As SCE explains in response to our data request:

> The PV dependability is used in the distribution planning process to determine how much of the existing and forecast PV would be available to serve load during the

> system peak. SCE applies the dependability curve at two different points of the planning process: adjustment of the recorded load and development of the forecast PV.
>
> To adjust the recorded load, SCE applies the dependability curve to the amount of existing NEM-connected PV based upon the time of the asset peak. For example, if a circuit with 2 MW of CEC AC nameplate of PV connected peaks at 12:30 pm (19.3% on the dependability curve) is 386 kW (2 MW * 19.3%) of the generation would be considered dependable and available to serve load. If that same circuit were to peak at 5 pm (2% on the dependability curve) the amount of generation available to serve load is reduced to 40 kW (2 MW * 2%). This adjusted loading value serves as a starting point for the 10-year forecast.
>
> SCE also uses the dependability curve to adjust its forecast of PV capacity. SCE starts by forecasting the CEC AC nameplate PV capacity at the system level and then disaggregating it to the circuit level. Once the nameplate capacity is forecasted for each circuit, the dependability curve is applied to determine how much capacity will be available to serve load based upon the historic peak of the circuit. For example, if 100 kW of PV is forecast for a circuit in 2020 and that circuit historically peaks at 12:30 pm (19.3% on the dependability curve), 19.3 kW (100 kW * 19.3%) of the generation would be considered dependable and available to serve load and incorporated into the forecast starting in 2020. If that same circuit were to peak at 5 pm (2% on the dependability curve) the amount of generation available to serve load is reduced to 2 kW per year (100 kW * 2%).[73]

Q. Why is this important?

A. SCE incorporates PV Dependability into its peak load forecasts for all of its distribution circuits, B-substations, and A-substations and it is the basis of its Distribution Substation Plan ("DSP") and Transmission Substation Plan ("TSP").[74] Underestimating PV Dependability means overestimating peak loads and overestimating the need for capacity-related capital expenditures.

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[73] SCE response to SEIA-Vote Solar Question 1.13

[74] SCE 02 Volume 03 R, pp. 30-31

As I stated previously, as much as $875 million of 2018-2020 capital in SCE's GRC application is influenced by the PV Dependability values.

Q. How does SCE determine PV Dependability?

A. SCE conducted an initial study in 2012 to determine the maximum and minimum output of a typical SCE customer's PV system. SCE gathered data from 184 PV installations throughout its service territory ranging in size from 1 kW to 1 MW.[75] SCE collected 24-hour, 15-minute interval data for PV output in the months of June-September in 2010 and 2011 ("Study Period") using Customer Solar Initiative ("CSI") meters. SCE concluded that the ***average of the minimum*** recorded values in each 15-minute interval from all 184 PV systems is the dependable amount of load SCE can reasonably expect PV to serve during peak load conditions.[76]

SCE re-evaluated the data in 2015 and discovered some anomalies, specifically zero values when PV should be producing energy. SCE attributed the issue to CSI meters not recording data properly due to communication problems. SCE's solution was to remove PV systems from the dataset that had all zeros recorded for both the maximum and minimum values, but to include systems from the dataset that had recorded values in maximum and all zeros for minimum. This resulted in the elimination of 18 PV systems in the dataset, leaving the output from 166 PV systems as the basis for the 2015 dependability curve peaking at 19.3% at 12:30 pm and declining to 2% at 5:00 pm, as shown below.

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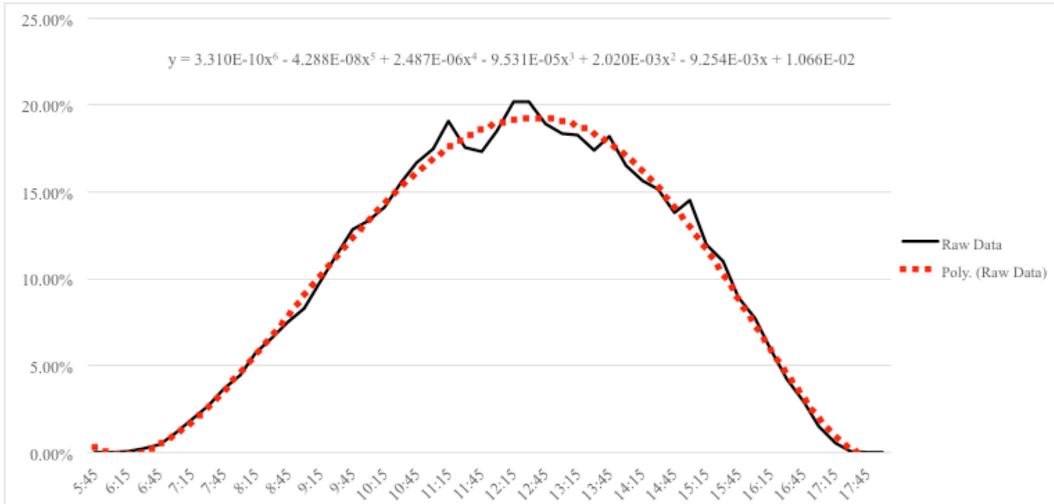
[75] SCE 02 Volume 03 R, Book A, Workpaper "SCE Dependable Photovoltaic Generation Study", p. 22

[76] *Id*., p. 23



SCE's 2015 PV Dependability Curve

Q. Why are the values in this curve so much lower than what SCE uses in its calculations of reverse power flow?

A. In response to our data request, SCE stated:

> As shown in figure 2-5 (on p. 25 of the workpaper "2015 Study Average Max and Min PV Output"[77]), the 2015 study conducted by SCE shows that the PV generation maximum output can be as high as 88.3% or as low as 20.2%. To determine the impact of DER on the system, the minimum potential output must be considered rather than the maximum dependable.[78]

Q. Does this response make sense to you?

A. No. This response contradicts SCE's approach to calculating reverse power flow, which considers maximum PV output during times of circuit minimum loads.

Q. Do you agree with SCE's approach to PV Dependability?

A. No, for two reasons. First, I believe SCE is negatively skewing the results by including systems with all zeros for the minimum. If a CSI meter

[77] SCE 02 Volume 3R, Book A

[78] SCE's response to SEIA-Vote Solar Question 7.1.c

recorded a zero value for any 15-minute interval over the Study Period, SCE sets the interval value to zero for the entire Study Period. Upon review of the data used by SCE in its calculation of PV Dependability, I discovered 13 PV systems with values of zero for 100% of the intervals[79], and another 7 PV systems with values of zero for at least 80% of the intervals.[80] I believe the data is bad, likely from CSI meters not recording properly, and the data should be cleaned up or the systems removed from the analysis.

Q. Why do you think the data is bad?

A. For many of the systems, the underlying PV output data consists of random integers ("1" or "0") for each interval.[81] For other systems, recorded PV output drops to zero at random times, resulting in a minimum output value of zero from the system for all or most intervals.

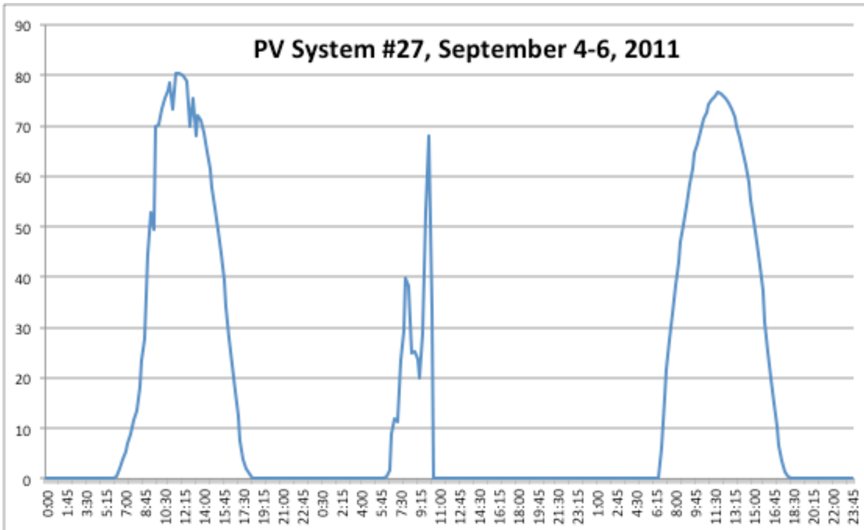
Q. For these other systems, is it possible that the PV output actually dropped to zero and the data is accurate?

A. It's possible but unlikely. For example, the recorded data for system #27 shows normal PV production for every day in the Study Period except for three days in September 2011. As shown below, the recorded PV output on September 5 abruptly drops to zero after 10:30am on September 5.

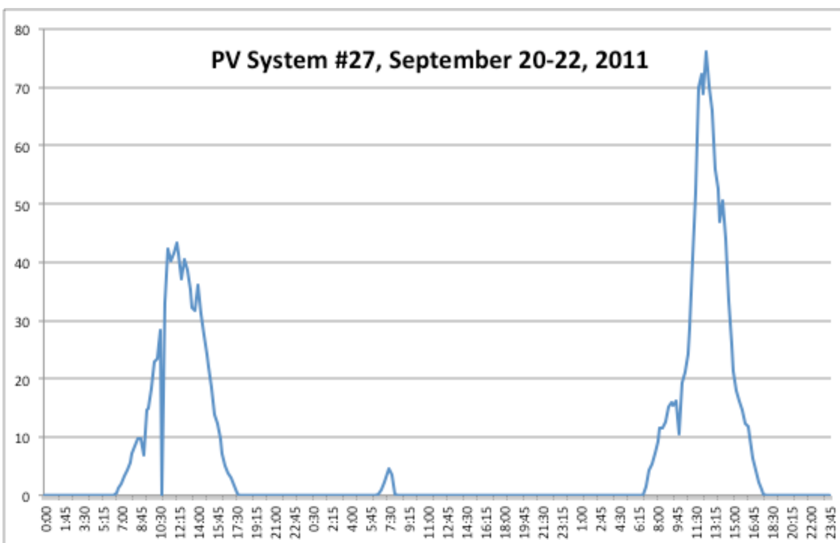
[79] See systems #39, #51, #58, #62, #69, #70, #72, #74, #78, #83, #139, #143, and #159 in the tab "Min Values – 2015" of the spreadsheet entitled "SEIA-Vote Solar-SCE-004 Q4.1_Workpaper PV Dependability Data and Results.xlsx" provided in response to SEIA-Vote Solar Question 4.1

[80] *Id.*, see systems #26, #27, #53, #56, #66, #77, and #174

[81] See for example systems #51, #58, #62, #69, #70, #72, #74, and #78 in the tab "2011 PV Data" of the spreadsheet entitled "TURN-SCE-091 Q2 Supp_PV Dependability Study Data 2010_2011.xlsx" provided in response to TURN Question 91.2



The recorded PV output also drops to zero at the 10:45am interval on September 20 and after 8:00am on September 21. Again, the data shows consistent, normal PV output for every other day in the Study Period. I believe these zero values do not reflect actual PV system output but rather bad data from the CSI meters not recording properly.



Q. **How has SCE reflected this data in its calculations of PV Dependability?**

A. Because of these data anomalies on three days in September and the way SCE calculates minimum output values, system #27 has zero output for all intervals after 8:00am in SCE's calculation of PV Dependability.[82] As I mentioned previously, there are numerous PV systems included in SCE's calculation of PV Dependability with zero values due to bad data.

Q. Why else do you disagree with SCE's approach?

Y. As I mentioned previously, SCE calculates PV Dependability based on the ***average of the minimum*** values at 15-minute intervals for every day in June through September. This approach includes cloudy, low PV output days, which may or may not coincide with circuit or substation peak demand days. As SCE has acknowledged in its response to SEIA-Vote Solar Question 1-13, what matters for distribution load forecasting is dependable PV output on circuit or substation peak load days.

Q. Has SCE calculated PV Dependability on circuit or substation peak load days?

A. No. In response to our data request, SCE indicated that it didn't know the circuits to which each PV system in its study is interconnected, and that "Due to the vintage of the data, obtaining interconnection information would require an extensive manual effort to go through each generator's application to look up and associate the circuit and substation information requested."[83]

Q. Were you able to estimate the PV Dependability on circuit or substation peak load days?

A. Yes. We cleaned up the data by eliminating the systems with random integer-only output values and ignoring missing values for systems such as #27. Since SCE is unable to provide circuit or substation peak day

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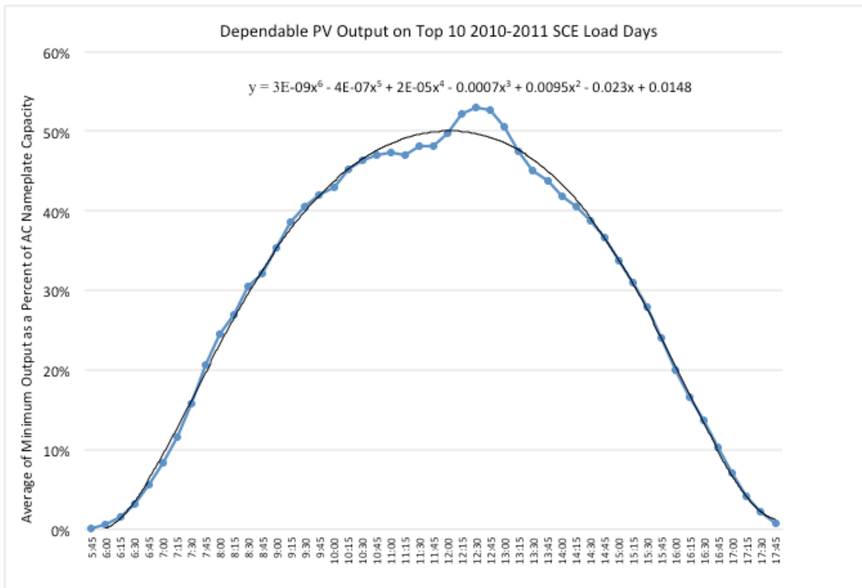
[82] See system #27 in the tab "Min Values – 2015" of the spreadsheet entitled "SEIA-Vote Solar-SCE-004 Q4.1_Workpaper PV Dependability Data and Results.xlsx" provided in response to SEIA-Vote Solar Question 4.1

[83] SCE response to SEIA-Vote Solar Question 4.2.b

information, we used the SCE DLAP top ten load days in 2010 and 2011[84] as a proxy and SCE's same ***average of the minimum*** approach. The resulting PV Dependability curve is shown below, peaking at 50% at 12:00 pm. This is significantly higher than the PV Dependability curve SCE used in its GRC application.



PV Dependability on SCE DLAP peak days and cleaned data

Q. What are the implications of higher PV Dependability values?

A. As I explained previously, PV Dependability directly influences SCE's peak load forecasts for all its distribution circuits, B-substations, and A-substations and is the basis of its DSP and TSP. As much as $875 million of 2018-2020 capital in SCE's GRC application is influenced by the PV Dependability values.

Q. Could SCE reduce its request for capacity-related capital expenditures by considering higher values for PV Dependability?

[84] 2010: July 15-16; August 18-19, 23-26; September 27-28. 2011: July 5-7; August 25-27, 29; September 6-8. Source: CAISO

A. Yes. By considering higher contributions from PV in reducing peak loads, SCE's load forecasts and associated need for capacity-related capital investment will decrease. In an effort to determine how much could be saved, we asked for new capital expenditure estimates at increasing levels of PV Dependability in a data request. SCE responded that it is unable to provide the information.[85]

Q. Do other California IOUs utilize the concept of a PV Dependability curve in their load forecasting?

A. PG&E explained in their most recent GRC application[86]:

> Beginning with the 2012 annual planning cycle and implementation of Integral Analytics' LoadSEER tool, PG&E's distribution load growth projections have incorporated energy efficiency (EE), demand response (DR), and distribution generation (DG) load impacts in the following ways:
>
> - Load impacts from existing interconnected DG, (including solar DG and small DG typically considered to be less than 500 kW), from historic DR, and from historic EE measures are embedded in the historic observed peak loads. This historic data, inclusive of the impacts of DG, DR and EE, is used to determine the level of temperature normalized historic peak demand in the LoadSEER geospatial forecasts used and accounted for in PG&E's distribution planning process …
>
> Incorporating EE, DR and DG into the underlying load growth projections ensures DERs are reflected in the need for capacity additions. Note that PG&E considers DERs to be DG as well as EE and DR.
>
> PG&E uses annual recorded peak demand readings at the feeder and bank level as the historic input to LoadSEER … Bank and feeder peaks can also be adjusted upward by discounting generation to ensure demand does not exceed capacity if the generation output is not available during

[85] SCE response to SEIA-Vote Solar Question 4.3.a

[86] PG&E response GRC-2017-PhI_DR_TURN_035-Q03, January 15, 2016

> peak periods. Adjustments are generally made in the following manner:
>
> - … For Solar generation, the adjustment process only applies to systems with output greater than 500 kW. All solar units less than 500 kW are considered to reduce peak based on historical performance and are not discounted in forecast. Using the date and time of the recorded peak demand and a solar hourly load shape or output (as shown below), the solar adjustment to the peak can be determined.

PG&E's July/August Average PV Gen Profile (Non-Residential)

Hour	% Output of Connected Rating
12:00 am to 04:00	0%
05:00	1%
06:00	10%
07:00	28%
08:00	48%
09:00	64%
10:00	75%
11:00	81%
12:00 (noon)	82%
13:00	78%
14:00	69%
15:00	56%
16:00	38%
17:00	19%
18:00	4%
19:00 – 23:00	0%

Q. How does PG&E's approach compare to SCE's?

A. There are two significant differences. First, PG&E does not adjust or discount the output of PV systems under 500 kW in its load forecast. SCE applies its dependability curve to all NEM-connected PV systems regardless of size.

Second, the PV adjustment factors used by PG&E are significantly higher than what SCE uses (e.g., 82% at noon for PG&E vs. 19% for SCE) and actually look similar to what SCE uses in its calculations of reverse power flow. To say it differently, PG&E attributes significantly more peak load reduction capability to PV than what SCE does.

Q. Is the fact that SCE heavily discounts PV systems < 500 kW significant?

A. As of December 31, 2016, SCE had 210,207 PV systems with nameplate ratings of 500 kW or less with a total capacity of 1,405.3 MW.[87] So yes, this is significant.

Q. What do you recommend?

A. First, it is critically important that the Commission address the issue of PV Dependability in one of its ongoing proceedings. Specifically, I believe it's important for all stakeholders to clearly understand how each IOU calculates and applies PV Dependability in distribution load forecasting, and for the Commission to establish more consistency across the IOUs.

It's logical that these issues be addressed in DRP Track 3, Sub-track 1 by the DER Growth Scenarios and Distribution Load Forecasting Working Group. We intend to raise the issue at the May 3, 2017 Working Group meeting focused on distributed generation.

The Commission should require SCE to develop a new PV Dependability curve consistent with the recommendations of the Track 3, Sub-track 1 Working Group (or as directed through another proceeding) and consistent with the other California IOUs, and to use this new curve in all future distribution load forecasts and associated requests for capacity-related capital investments.

For the purposes of this proceeding, given the flaws in its PV Dependability analysis discussed above, SCE has not demonstrated that its proposed $875 million of capacity-related costs are just and reasonable. Accordingly, absent a further showing by SCE, I recommend that the Commission disallow the $875 million. For SCE to recover any of the requested $875 million it must, at minimum, develop new load forecasts using a revised PV Dependability curve based on cleaned-up data and PV system output on

[87] SCE response to SEIA-Vote Solar Question 6.3.a

circuit peak days, also considering the impacts of DR and storage as discussed below, and submit a new request for capacity-related projects for the Commission to review as part of this proceeding.

6.2 Demand Response and Energy Storage

Q. How else has SCE failed to fully reflect contributions from DER?

A. Even though SCE incorrectly includes storage in its calculations of reverse power flow, the Company has neglected to include the impacts of demand response and energy storage in its load forecasts used for distribution planning.[88]

Q. Why does SCE exclude the impacts of DR in its load forecasts?

A. SCE considers DR to be non-dependable, and explains:

> Demand response events are initiated by CAISO at unpredictable times throughout the year, not guaranteeing that a future demand response event will be called on the peak day for the asset impacted by a past demand response event. When a demand response event is called, the amount of load reduction is unpredictable. Without direct load control, customers can opt out of the demand response event and not participate, continuing to consume load. There also may be scenarios where customers are not consuming load during the demand response event which would not reduce any load on distribution equipment. In addition, customers presently enrolled in a demand response program are not guaranteed to continue participation in the future.
>
> SCE does not presently have the ability to dispatch demand response at a local level to meet distribution needs; demand response events can presently only be dispatched at the wholesale level. New DR programs or contracts need to be developed in order to meet distribution needs and be considered dependable. SCE is researching how demand response can be included in future forecasts. Part of the Distribution Resources Plan

[88] SCE response to SEIA-Vote Solar Questions 1.21, 1.24

> proceeding is focusing on Forecasting and Growth Scenarios. That proceeding analyzes how DER growth is included in the distribution planning forecast including demand response.[89]

Q. Do other California IOUs include DR in their load forecasts?

A. Yes. As PG&E explained in its last GRC:

> To the extent that they are incorporated by PG&E and in the California Energy Commission's adopted California Energy Demand base case peak load forecast, the LoadSEER geospatial forecasts incorporate projected future load impacts due to:
>
> - DG
> - EE
> - Non-event based DR (such as time of use rates and permanent load shifting)
> - Event based DR (such a peak day pricing and SmartRate)[90]

Q. Is it premature for SCE to include the impacts of storage in its load forecasts?

A. No, as SCE is experiencing significant growth of storage resources on its system. The Company explains:

> In addition to accelerated growth in distributed solar, the grid is also seeing dramatic growth in distributed storage. Through SCE's Local Capacity Resources (LCR) solicitation, SCE's first stand-alone storage solicitation and previous solicitations, SCE has procured over 200MW of distribution and customer-connected storage with forecast deployment of 50 MW of customer-connected storage through customer-incentive programs. And this does not include the several ongoing procurement activities that may deploy additional distributed storage, such as SCE's Preferred Resources Pilot, SCE's 2016 stand-alone storage solicitation, and the Aliso Canyon

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[89] SCE response to SEIA-Vote Solar Question 1.22

[90] PG&E response GRC-2017-Phl_DR_TURN_035-Q03, January 15, 2016

energy storage solicitation.[91]

Q. Has SCE explained why it does not include storage in its load forecasts?

A. Yes. In response to our data request, SCE explains that it does not currently include energy storage in its distribution forecast due to the uncertainty of the operation of the energy storage device, and that the DRP Track 3, Sub-Track 1 process is determining how to incorporate the impact of all DERs, including energy storage, into the forecast.[92]

Q. What do you recommend?

A. As is the case with PV Dependability, I believe it is critical for all stakeholders to understand how each IOU incorporates DR and storage in load forecasting, and for the Commission to establish consistency across the IOUs. It's again logical to address this in the DRP Track 3, Sub-track 1 proceeding. According to the preliminary schedule, I understand that the Working Group discussed DR at its April 26 meeting and will discuss storage at its May 3 meeting.[93]

For the purposes of this proceeding, as noted above, I recommend that the Commission disallow $875 million of capacity-related costs, require SCE to develop new load forecasts using a revised PV Dependability curve based on cleaned-up data and PV system output on circuit peak days, also considering the impacts of DR and storage, and develop a new request for capacity-related projects for the Commission to review as part of this proceeding.

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[91] SCE 02 Volume 10, pp. 2-3

[92] SCE response to SEIA-Vote Solar Question 1.24

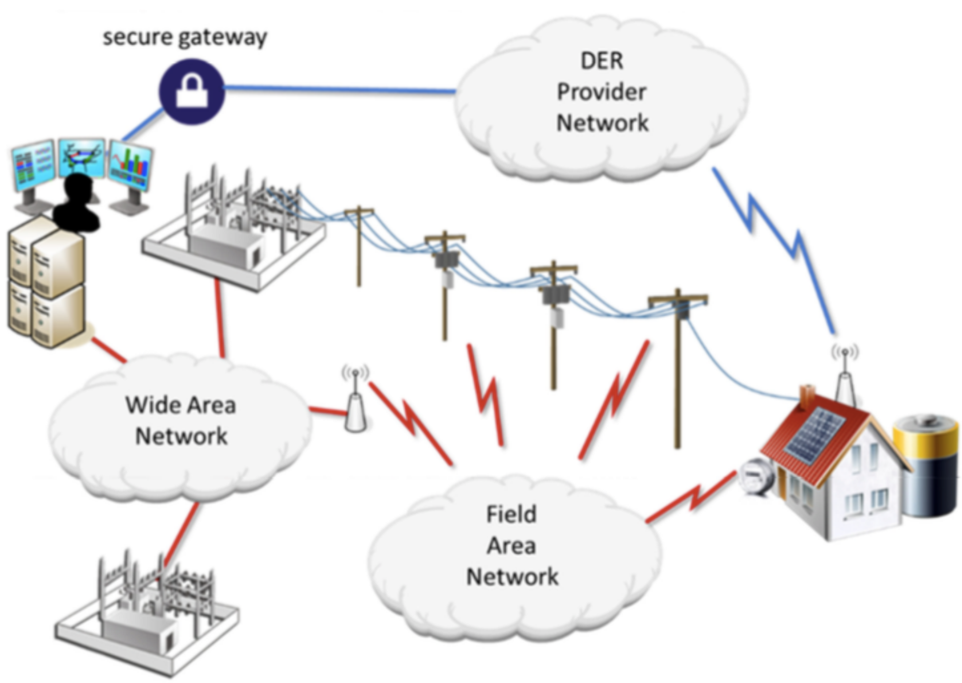
[93] See http://drpwg.org/growth-scenarios/

6.3 Third-party Communication and Control Infrastructure

Q. Does SCE's vision for grid modernization include direct utility dispatch/control of DER, third-party dispatch/control, or both?

A. It's difficult to determine. SCE includes a few diagrams in its GRC application, such as the one below[94], that indicate exclusive third-party interaction with DER.

Figure I-3
Communications Programs



Elsewhere in its application, SCE makes statements such as "System operators now require enhanced operational capabilities and better tools to assess, monitor, analyze and control grid assets and DERs"[95].

In response to our data request related to DR, SCE states:

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[94] From SCE 02 Volume 10, p. 15.

[95] SCE 02 Volume 10, p. 18

> SCE does not have the ability to dispatch demand response programs/resources at a granular distribution level today. This capability would be obtained with the implementation of a GMS, specifically with DERMS functionality. Once a GMS was implemented such that we had the capability of distribution level, location-specific control of demand response, (incorporating it into the planning process) can be realized."[96]

This implies that SCE has approached its grid modernization design with the intent of direct utility control of DER.

Q. How does SCE distinguish between GMS and DERMS?

A. SCE explains that DERMS functionality is a subset of the broader GMS capabilities, and DERMS typically facilitates monitoring and management of DER. DERMS may include the following capabilities:

- DER monitoring, control, optimization
- DER portfolio management
- DER forecasting
- Microgrid management[97]

Q Do you agree that SCE needs DERMS capabilities?

A. Yes. As DER penetrations increase and as DER aggregators become more active in the market, it is important for SCE to establish DERMS capabilities.

Q. Is it important for SCE to rely on third-party communications for control and dispatch of DER?

A. To minimize redundancy and potential stranded costs, it is very important that SCE rely on existing and emerging third-party communications infrastructure as much as possible.

[96] SCE response to SEIA-Vote Solar Question 2.6

[97] SCE 02 Volume 10 p. 110

Utilities have long relied on third parties and their communications networks for control and dispatch of DER. For example, residential DR resources have been dispatched using third party radio networks in Direct Load Control programs for switching on/off air conditioning and water heating for decades. More recently, third parties[98] are providing DR and load aggregation programs, such as with smart thermostats, with control using secure standard protocols over the public internet.

Q. Has the Commission already recognized the importance of considering third-party alternatives?

A. Yes. The Commission has already recognized the importance of considering third-party alternatives for communications/control of DER in its Decision on DRP Track 2 Demonstration Projects. The Decision states:

> Vote Solar is correct that the: "[D]emonstration projects provide an ideal environment to evaluate if third-party dispatched resources can provide reliable, consistent response to utility signals, and if reliance on third-party controlled DER and third-party owned communications infrastructure is more cost effective."
>
> The utilities should provide a clear basis for any reliance on utility-owned assets, and accordingly the utilities are directed to do a side-by-side comparison of the costs and cost-effectiveness of third-party and utility-controlled DER alternatives, and should also explain how the DER portfolio was chosen.[99]

Q. Has SCE taken steps to enable third-party DER communication and control?

A. Yes. SCE's Advice Letter, approved by the Commission on April 7, 2017, describes new requirements in Rule 21 including:

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[98] Companies such as Nest, Ecobee, EnergyHub, Honeywell, Schneider, Tendril and Ecofactor, among others

[99] Decision 17-02-007 Re: Decision On Track 2 Demonstration Projects, February 9, 2017, p. 28

- All inverter-based DER systems shall be capable of communications;
- Initially, the communication requirements shall be between (a) IOUs and individual DER systems, (b) IOUs and facility DER energy management systems, which manage DER systems within a facility, plant and/or microgrid, and (c) IOUs and retail energy providers / aggregators / fleet operators, which manage and operate DER systems as various facilities[100].

Q. What do you recommend?

A. As previously stated, I recommend that the Commission reject SCE's request for approval of its proposed advanced distribution automation program, which includes the FAN, WAN, and GMS. I do, however, recommend that the Commission authorize SCE to proceed with a DERMS implementation and to deploy the minimum technology necessary to satisfy the new DER communication requirements of Rule 21 while fully leveraging the monitoring, communication and control capabilities inherent in most DER technologies.

7 Summary of Conclusions and Recommendations

Q. Please summarize your conclusions and recommendations for the Commission

A. I conclude that SCE's forecast of residential PV growth is significantly higher than what market analysts expect in California in the 2017-2020 period. I also conclude that SCE is exaggerating the negative and underestimating the positive impacts of DER in its GRC application, resulting in:

[100] SCE Advice Letter 3532-E (submitted December 20, 2016), p. 3

- Proposed capital expenditures that are unnecessary at SCE's current and projected levels of DER penetration;
- An overstated need for capacity-related capital expenditures; and
- A proposed grid modernization program that is extremely costly and fails to deliver net benefits to ratepayers.

I recommend that the Commission:

1) Adopt ORA's recommendation to disallow $1.66 billion of SCE's 2018-2020 request to fund its grid modernization program and to only authorize distribution automation expenditures consistent with historical spending.

2) Disallow $875 million of capacity-related costs in this GRC application. If SCE seeks to recover any capacity-related costs, then it must develop new load forecasts using a revised PV Dependability curve based on cleaned-up data and PV system output on circuit peak days, also considering the impacts of DR and storage, and submit a new request for capacity-related projects for the Commission to review as part of this proceeding.

3) Require SCE to develop a new PV Dependability curve consistent with the recommendations of the Track 3, Sub-track 1 Working Group (or other proceeding) and consistent with the other California IOUs, and to use this new curve in all future distribution load forecasts and associated requests for capacity-related capital investments.

4) Authorize SCE to proceed with a DERMS implementation and to deploy the minimum technology necessary to satisfy the new DER communication requirements of Rule 21 while fully leveraging the monitoring, communication and control capabilities inherent in most DER technologies.

5) Disallow SCE's 2018-2020 request for $129 million for subtransmission relay replacements, and only authorize expenditures for replacement of distance relays where SCE has conducted sufficient engineering analysis to demonstrate the potential risk of load encroachment over the 2018-2020 GRC period.

Q. Does this conclude your testimony?

A. Yes.

Appendix A: Southern California Edison Company Responses to Data Requests Cited in Testimony

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET ORA-SCE-203-TCR

To: ORA
Prepared by: Eric Nunnally
Title: Engineering Manager
Dated: 02/28/2017

Question 08:

Originated by: Tom Roberts

Exhibit Reference: SCE-2
SCE Witness: Multiple
Subject: Electric T&D, miscellaneous

Please provide the following:

8. Do the grid modernization investments requested in the current GRC represent all the upgrades SCE anticipates will be required to fully integrate DER into safe and reliable grid operations, including the ability to have DERs and microgrids dispatched through a distribution system operator or DSO? If not, please explain and describe any other investments SCE currently believes will be required.

Response to Question 08:

SCE believes the programs described in the Grid Modernization volume are foundational expenditures, as they are justified on their benefits toward safety and reliability, but would also be necessary in any future scenario for facilitating integration of DERs. These foundational expenditures also provide the basis for the required visibility needed at the T-D interface, associated with the role of the DSO in the interaction with the CAISO. Other technologies may be identified as necessary to "fully integrate DERs" based on future and ongoing DER related research, pilots, and demonstrations. Due to the uncertain future of other DER related applications, including microgrids, we do not believe additional expenditures in these areas are warranted at this time until further clarity is provided as to the opportunities to benefit customers. Due to the size of SCE's system, deploying the required technology will take 10 years to cover 60% of SCE's total urban distribution circuits.

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET ORA-SCE-031-TCR

To: ORA
Prepared by: Eric Nunnally
Title: Project Manager
Dated: 10/14/2016

Question 13:

Originated by: Tom Roberts

Exhibit Reference: SCE-2, volume 10
SCE Witness: R. Ragsdale
Subject: Electric T&D, Grid Modernization, Distribution Automation (DA), scope

SCE is currently developing a LNBA, Demo B, and has proposed to field test this LNBA methodology, Demo C, as part of the DRP proceeding, R.14-08-013. Was the methodology described on pages 62-93 of the workpapers designed to provide consistent results with the LNBA developed through DRP Demo B and C? If not, please explain why SCE is proposing two incompatible methodologies?

Response to Question 13:

The two methodologies mentioned were developed with two separate goals in mind and as a result, may not provide consistent results. The LNBA methodology is intended to calculate avoided cost benefits for customer installed DER at specific locations. The grid modernization prioritization methodology was developed as a means to prioritize deployment of several interrelated technologies including distribution automation, substation automation, and telecom infrastructure across SCE's entire service territory such that full capabilities are realized and the greatest potential for DERs to provide grid benefit is enabled.

They are related in the sense that they both are using location (approximate or specific) of DERs to calculate an estimated benefit. Where they differ is that they are used for different objectives -- the LNBA methodology tabulates benefits that DER can provide to customers in a very specific location vs. priortization methodology is based on grid benefit from DER downstream of a specific grid asset. In future updates to a deployment prioritization methodology, we do expect to incorporate LNBA results where possible. Below are brief descriptions of the two methodologies described here.

The LNBA methodology is being developed as part of DRP Demo B and will supply the benefits of installing DER in a location based on an avoided cost methodology defined in the "Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B" issued on May 2, 2016. Demo B will develop and calculate the LNBA on a set of identified projects within a particular Distribution Planning Area. The objective of Demo C, as established in the DRP's Final Guidance, is to analyze how the LNBA can be validated as a field demonstration. Demo C will demonstrate the ability of a portfolio of DERs to be integrated into both utility planning and operations and support achievement of state policy goals. The LNBA will calculate the following characteristics for a specific location:

- Avoided Transmission and Distribution project costs
- Avoided Generation Capacity
- Avoided Energy
- Avoided Greenhouse Gas
- Avoided Renewables Portfolio Standard
- Avoided Ancillary Services
- Avoided Renewable Integration costs
- Societal (e.g. environmental) impacts if values can be calculated
- Public Safety Impacts if values can be calculated

The Grid Modernization components including FAN, WAN, substation automation, distribution automation, and their related circuit tie upgrades outlined in the Grid Modernization Volume will be deployed in a prioritized manner that leverages a prioritization methodology, favoring locations where DERs can provide the most grid benefit. This is balanced with needs for dispersion of work across the territory, and adequate clustering of activities such that technologies sufficiently support each other. Once the CPUC approves the Locational Net Benefits Methodology (LNBM) in the DRP proceeding, SCE will, where possible, integrate the LNBM into the methodology for prioritizing the Grid Modernization Deployment Plan. Pages 62-93 of the workpapers for our Grid Modernization volume of testimony explain in detail how grid benefit is translated into a score for each grid asset.

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-003

To: SEIA; VOTE SOLAR
Prepared by: Joel Karzen
Title: Project Manager
Dated: 03/03/2017

Question 03.1:

3.1 Please provide a spreadsheet containing the following information for each of the 588 Subtransmission relays SCE intends to replace under its Subtransmission Relay Upgrade Program:

a) Relay age
b) Likelihood of relay failure in the 2018-2020 time period
c) Whether the relay would have been replaced in the 2018-2020 timeframe absent DER
d) Whether the relay is a distance or overcurrent relay
e) Whether the relay is protecting a looped or radial system
f) Current DER penetration
g) DER penetration at which load encroachment or false tipping would occur
h) Year at which SCE expects DER penetration of g) and load encroachment or false tripping to occur
i) Other alternatives considered to mitigate the potential load encroachmentor false tripping (e.g., adjusting relay settings, sourcing reactive power,etc.)

Response to Question 03.1:

a) Please refer to the attachment SEIA 003 Q 3.1.xlsx, populated where data is available.
b) SCE has performed relay failure analysis for specific model types which can be found in SCE's response to TURN-SCE-26, Q55.
c) Please refer to the attachment SEIA 003 Q 3.1.xlsx, yes values are where the relay has been identified to be replaced by another project.
d) Please refer to the attachment SEIA 003 Q 3.1.xlsx.
e) Subtransmission relays are typically networked (looped) off of the low side of an A Bank transformer. In some cases there are lines (with associated relays) that are radially fed off the network; for these, the data is not readily available and would be overly burdensome to obtain.
f) Please refer to the attachment SEIA 003 Q 3.1.xlsx, populated where data is available.
g) SCE cannot accurately predict when this will occur unless a detailed engineering study was performed of each relay on the list. SCE did provide SEIA a list, by substation, when SCE predicts reverse power flow to occur in SEIA-Vote Solar-SCE-001 Q 1.27h.
h) See SCE's response to SEIA-Vote Solar-SCE-003 Q3.1 part g.
i) SCE did consider alternatives to mitigate load encroachment, a more detailed discussion

can be found in TURN-SCE-026, Q 4d.

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-001

To: SEIA; VOTE SOLAR
Prepared by: Eric Nunnally
Title: EMG
Dated: 02/10/2017

Question 01.32:

SCE-02 Volume 10 – Grid Modernization

1.32 Please provide examples of other utilities that have implemented the three mid-point switches and three circuit-tie Distribution Automation (DA) design proposed by SCE, and explain the associated reliability improvements attributable to these DA investments.

Response to Question 01.32:

SCE does not have ready access to examples of other utilities that have implemented a three mid-point, three-tie switch distribution automation design. SCE has conducted its own analysis to determine the attributable reliability benefits specific to its territory. SCE's plans are based on the specific characteristics of its system. SCE's quantification of the reliability benefits of the Distribution Automation program were provided in SCE's response to TURN-SCE-026 Question 55 in a file entitled, "SCE reliability technology BCA.xlsx". This analysis shows a compelling benefit-to-cost ratio for three mid-point switches and three circuit ties. Additional reasoning SCE used as support for the proposed distribution automation design is also provided in response to SEIA-Vote Solar-SCE-001 Question 1.31.

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-001

To: SEIA; VOTE SOLAR
Prepared by: Eric Nunnally
Title: EMG
Dated: 02/10/2017

Question 01.31:

SCE-02 Volume 10 – Grid Modernization

1.31 Please provide all data and analysis supporting SCE's conclusion that providing three mid-point switches and three circuit-ties per circuit provides the optimal tradeoff between ratepayer costs and system reliability

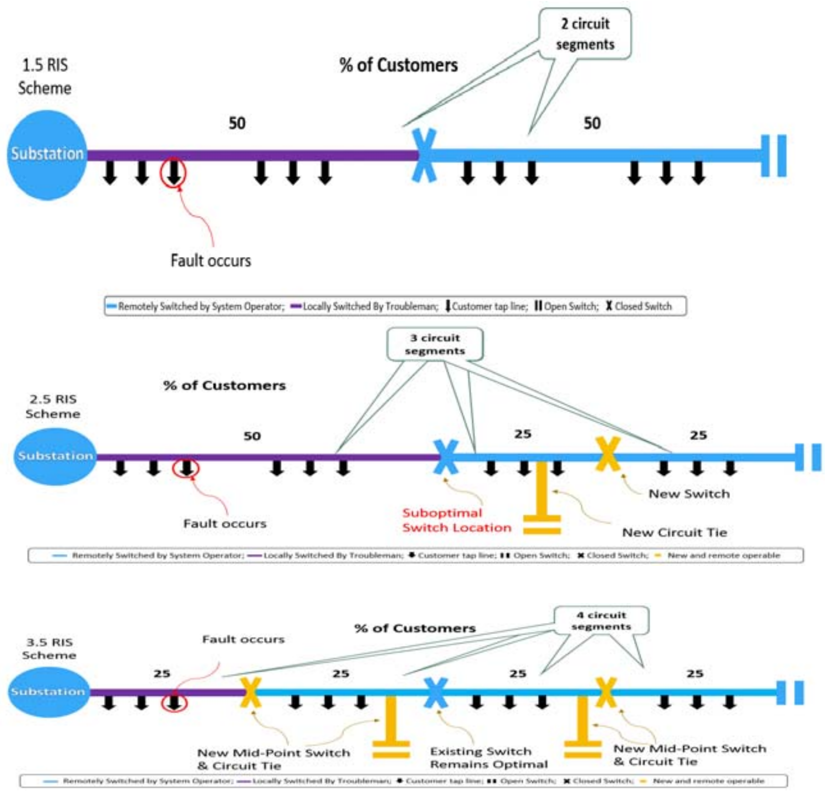
Response to Question 01.31:

The proposed distribution automation standard of three mid-point switches and three circuit-ties per circuit is an ultimate design standard and would not be applied to every circuit initially. The level of appropriate distribution automation would be determined on a circuit-by-circuit basis using the methodology described in workpaper pages 106-109.

The ultimate design standard of three mid-point switches and three tie switches per circuit offers benefits in circuit reliability as well as other benefits. This quantification of the reliability benefits of the Distribution Automation program proposed for years 2018 - 2020 were provided in SCE's response to TURN-SCE-026 Question 55 in a file entitled, "SCE reliability technology BCA.xlsx". Additional benefits lie in the areas of: (1) operability and accuracy of circuit parameter information provided to operators (as described in Workpapers to SCE-2, Vol. 10, pp. 102-114); and (2) realizing DER benefits. While the value of these non-reliability benefits have not yet been quantified, the value of the reliability benefits (which have been quantified) alone demonstrate the importance of the proposed Distribution Automation program and its three mid-point three tie switch design to the ratepayer.

Another consideration given in the development of three mid-point switches and three circuit-ties per circuit as the ultimate design standard was that the existing automation standard is 1 mid-point switch and 1 circuit tie per circuit. The mid-point switch is installed on the circuit such that ~50% of customer load is downstream of its location. Increasing the distribution automation standard to two mid-point switches and two circuit-ties per circuit on a circuit with an existing automation scheme makes it difficult to leverage the existing mid-point automated switch as the balance of load between each automated switch is uneven. The result is either a suboptimal automation design with uneven distribution of customers between mid-point switches, or an inability to leverage the existing mid-point switch to achieve a balanced customer load between mid-point switches.

To explain this challenge the following visuals are provided.



Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-001

To: SEIA; VOTE SOLAR
Prepared by: Eric Nunnally
Title: EMG
Dated: 02/10/2017

Question 01.35:

SCE-02 Volume 10 – Grid Modernization

1.35 Please provide a lower bound and upper bound estimate of the cost per CMI for residential, small C&I, and medium/large C&I customers in SCE's service territory.

Response to Question 01.35:

The lower and upper bound estimates of the cost per CMI for residential, small C&I, and medium/large C&I customers in SCE's service territory are not readily available.

The average cost per CMI provided in SCE-2, Vol. 10, Workpaper pp. 122 - 129, was calculated by Nexant, Inc. whom we believe to be the leading expert in this field. Nexant has not made available to SCE all the details and methods of its analysis.

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET TURN-SCE-052

To: TURN
Prepared by: Roger Lee
Title: Principal Advisor
Dated: 02/15/2017

Question 09.b:

9. Regarding Table 1-1 on p. 124 of the workpapers,

   b. Please provide the values for each field and year, disaggregated by customer class and class size, similar to Table ES-1 on p. xii of the document referenced in Footnote 2 of p. 124 of the workpapers (Sullivan, M.J., J. Schellenberg, and M. Blundell (2015)) or Table 1-2 on p. 6 of the document referenced in Footnote 3 (Sullivan, M.J., J. Schellenberg and others (2012)). Pacific Gas & Electric Company's 2012 Value of Service Study, or any other way SCE breaks it out by customer class and/or class size.

Response to Question 09.b:

Table 1 provides the interruption costs per CMI by customer class, including the two size categories for C&I customers.

Table 1: Interruption Costs per Customer Minute Interrupted by Customer Class

Customer Class	Year	Total # of Interruptions	Avg. # of Customers Affected	Total CMI	CAIDI (Minutes)	Total Estimated Costs (2016$)	Cost per CMI (2016$)	
							Lower Bound	Upper Bound
Medium and Large C&I	2013	23,385	4.6	12,502,256	115.4	$417,459,753	$33.39	$56.02
	2014	24,497	4.7	13,627,899	118.3	$440,323,139	$32.31	$54.21
	2015	26,123	4.1	20,655,836	191.2	$508,394,142	$24.61	$41.29
	Average	**24,668**	**4.5**	**15,595,330**	**141.6**	**$455,392,345**	**$29.20**	**$48.99**
	2013	24,068	21.8	59,791,935	113.9	$452,665,970	$7.57	$12.70
				64,245,53		$498,808,12		

Small C&I	2014	25,143	22.0	7	116.1	0	$7.76	$13.03
	2015	26,949	19.5	67,514,401	128.5	$481,809,714	$7.14	$11.97
	Average	**25,387**	**21.1**	**63,850,624**	**119.5**	**$477,761,268**	**$7.48**	**$12.55**
Residential	2013	23,393	166.6	438,486,858	112.5	$20,727,677	$0.05	$0.08
	2014	24,384	170.7	483,978,104	116.2	$21,777,314	$0.04	$0.08
	2015	26,095	152.4	489,791,586	123.2	$21,695,429	$0.04	$0.07
	Average	**24,624**	**163.2**	**470,752,182**	**117.3**	**$21,400,140**	**$0.05**	**$0.08**
All	2013	24,198	187.2	510,781,049	112.8	$890,853,398	$1.74	$2.93
	2014	25,289	191.1	561,851,540	116.3	$960,908,574	$1.71	$2.87
	2015	27,074	170.2	577,961,823	125.4	$1,011,899,290	$1.75	$2.94
	Average	**25,520**	**182.8**	**550,198,137**	**118.1**	**$954,553,754**	**$1.73**	**$2.91**

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-005

To: SEIA; VOTE SOLAR
Prepared by: Kevin Clampitt
Title: Consultant
Dated: 03/15/2017

Question 5.7:

5.7 Please provide all data and analysis supporting SCE's estimate of 20 million CMI reduction from "Avoided CMI increase resulting from DER adoption" in row 14 of tab "8. CMI Benefits" of the spreadsheet entitled "SCE reliability technology BCA.xlsx".

Response to Question 5.7:

The calculation and assumptions associated with the 20 million CMI increase resulting from DER adoption was provided in our Supplemental Response to TURN-SCE-026 Q55 in attachment titled "S-55-9 DER Impact on Reliability.xlsx."

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-007

To: SEIA; VOTE SOLAR
Prepared by: Talal Hanna
Title: Engineer
Dated: 04/13/2017

Question 7.5:

Please explain why SCE believes CHP and energy storage contribute to reverse flow, as indicated by columns F-G and N-O.

Response to Question 7.5:

CHP and energy storage systems can contribute to reverse flow when an installer elects to discharge during off-peak and/or minimum load hours. SCE believes that in the absence of discharge/charge restrictions, it is prudent to assume a worst-case scenario to ensure circuitry is not adversely impacted due to the discharging of CHP and/or energy storage.

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-007

To: SEIA; VOTE SOLAR
Prepared by: Talal Hanna
Title: Engineer
Dated: 04/13/2017

Question 7.1 a-e:

7.1 All questions in this Data Request relate to the spreadsheet titled "S-55-9 DER Impact on Reliability.xlsx" which SCE provided as a Supplemental Response to TURN-SCE-026 Q55, and the hidden tab labeled 'Min Load and PV Adj'.

1) Columns D and E are labeled 'Hour' and 'Curve'. The values in these two columns reflect the following relationship:

Hour	Curve
0	0.0%
1	0.6%
2	0.048%
3	0.041%
4	0.043%
5	0.045%
6	2.9%
7	23.0%
8	46.5%
9	65.6%
10	79%
11	85.5%
12	88.7%
13	86.8%
14	77.5%
15	64.9%
16	47.1%
17	22.1%
18	1.3%
19	0.048%
20	0.044%
21	0.041%
22	0.041%
23	0.041%
24	50%

a. Please provide the source for this data.

b. SEIA and Vote Solar assume that the values represent PV output % of nameplate at various hours of the day, with Hour 0 equal to midnight, Hour 12 equal to noon, Hour 18 equal to 6pm, etc.
Please confirm that this is correct or clarify what these values represent.

c. If b. is correct, please explain why these values differ from the values in SCE's PV Dependability curve, described in the workpaper titled "SCE Dependable Photovoltaic Generation Study".

d. If b. is correct, please confirm that PV output should be 0.0% for all night time hours and correct the spreadsheet accordingly.

e. If b. is correct, please explain why there are two different values for midnight (0% for Hour 0, 50% for Hour 24), please confirm that the correct PV output value for midnight is 0%, and correct the spreadsheet accordingly.

Response to Question 7.1 a-e:

a) The source of this data is a study performed by SCE in 2012 and re-evaluated in 2015 to determine the PV hourly minimum and maximum output. See WPSCE02V03RBkA page 25 figure 2-5 "2015 Study Average Max and Min PV Output" for additional information.

b) SEIA and Vote Solar's assumption is correct. Hour 0 equals midnight, Hour 12 equal noon, and Hour 18 equal 6pm.

c) As shown in figure 2-5 of the workpaper referenced in part a, the 2015 study conducted by SCE shows that the PV generation maximum output can be as high as 88.3% or as low as 20.2%. To determine the impact of DER on the system, the minimum potential output must be considered rather than the maximum dependable.

d) SCE conducted statistical analysis using the percentile method to determine minimum load. This analysis showed the minimum load hour to be midnight for a large number of feeders, as expected. Since the resources and tools necessary to conduct 8760 analyses on every such feeder were not available, SCE assumed that the PV output during daytime minimum load for such feeders to be 50% (typically occurring around 8 AM) to study the impact of PV during early day hours.

e) Yes, part b is correct. The revised sheet provided in the response to SEIA-Vote Solar-SCE-007, question 7.6, includes a correction for midnight values that were not 0.

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-007

To: SEIA; VOTE SOLAR
Prepared by: Talal Hanna
Title: Engineer
Dated: 04/13/2017

Question 7.3:

If 2) is correct, the data in column D show a large number of circuits with minimum load occurring between the hours of 9am and 6pm. Specifically:

Hour of minimum load	Number of circuits
9 (9am)	56
10 (10am)	45
11 (11am)	81
12 (noon)	170
13 (1pm)	171
14 (2pm)	111
15 (3pm)	31
16 (4pm)	21
17 (5pm)	17
18 (6pm)	8

Please confirm that these values are correct and, if so, please describe the nature of the customer mix and load characteristics of these circuits resulting in minimum loads occurring during the middle of the day. If thevalues are incorrect, please update the spreadsheet accordingly.

Response to Question 7.3:

These values are correct, based on statistical analysis (percentile method). Please see the attachment provided in the supplemental response to TURN-SCE-085, Q5 for circuit customer mix breakdown by type. It is important to note that SCE customer mix and load characteristics are inherently diverse, and that minimum loading on some feeders may occur during the middle of the day.

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-001

To: SEIA; VOTE SOLAR
Prepared by: Christopher Ohlheiser
Title: Engineer
Dated: 02/10/2017

Question 01.13:

1.13 Please explain and provide examples of how SCE applies its estimated PV dependability (i.e., 19.3% at noon, 2% at 5pm) in its load forecasting and distribution planning.t

Response to Question 01.13:

The PV dependability is used in the distribution planning process to determine how much of the existing and forecast PV would be available to serve load during the system peak. SCE applies the dependability curve at two different points of the planning process: adjustment of the recorded load and development of the forecast PV.

To adjust the recorded load, SCE applies the dependability curve to the amount of existing NEM-connected PV based upon the time of the asset peak. For example, if a circuit with 2 MW of CEC AC nameplate of PV connected peaks at 12:30 pm (19.3% on the dependability curve) is 386 kW (2 MW * 19.3%) of the generation would be considered dependable and available to serve load. If that same circuit were to peak at 5 pm (2% on the dependability curve) the amount of generation available to serve load is reduced to 40 kW (2 MW * 2%). This adjusted loading value serves as a starting point for the 10-year forecast.

SCE also uses the dependability curve to adjust its forecast of PV capacity. SCE starts by forecasting the CEC AC nameplate PV capacity at the system level and then disaggregating it to the circuit level. Once the nameplate capacity is forecasted for each circuit, the dependability curve is applied to determine how much capacity will be available to serve load based upon the historic peak of the circuit. For example, if 100 kW of PV is forecast for a circuit in 2020 and that circuit historically peaks at 12:30 pm (19.3% on the dependability curve), 19.3 kW (100 kW * 19.3%) of the generation would be considered dependable and available to serve load and incorporated into the forecast starting in 2020. If that same circuit were to peak at 5 pm (2% on the dependability curve) the amount of generation available to serve load is reduced to 2 kW per year (100 kW * 2%).

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-004

To: VOTE SOLAR; SEIA
Prepared by: Christopher Ohlheiser
Title: Engineering Manager
Dated: 03/14/2017

Question 4.2.b:

4.2 Please provide a spreadsheet containing the following information for each of the 166 PV systems included in SCE's 2015 PV Dependability Study:

b) Substation and circuit to which the PV system is interconnected

Response to Question 4.2.b:

Interconnection data is not readily available. Only the generation output information was required in SCE's 2015 PV Dependability Study and the interconnection information was not included. Due to the vintage of the data, obtaining interconnection information would require an extensive manual effort to go through each generator's application to look up and associate the circuit and substation information requested.

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-004

To: VOTE SOLAR; SEIA
Prepared by: Christopher Ohlheiser
Title: Engineering Manager
Dated: 03/14/2017

Question 4.3.a:

4.3 Using similar PV output profile shapes as shown in Figure 2-5 at p. 25 of the workpaper entitled "SCE Dependable Photovoltaic Generation Study", please provide revised values for Table IV-14 at p. 57 of SCE-02 Volume 03 R, assuming:

a) Peak average minimum PV system output of 25% at 12:15pm

Response to Question 4.3.a:

SCE has not performed this analysis in the past, and did not perform this analysis as part SCE's 2018 GRC application. Gathering this information would require SCE to create a new data set. Since SCE does not utilize the information requested in its distribution planning process or in SCE's 2018 GRC application, SCE is unable to provide the requested information.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase I
Application 15-09-001
Data Response

PG&E Data Request No.:	TURN_035-Q03		
PG&E File Name:	GRC-2017-PhI_DR_TURN_035-Q03		
Request Date:	December 18, 2015	Requester DR No.:	035
Date Sent:	January 15, 2016	Requesting Party:	The Utility Reform Network
PG&E Witness:	Satvir Nagra	Requester:	Hayley Goodson

SUBJECT: ELECTRIC DISTRIBUTION CAPACITY (PG&E-4, CHAPTER 13)

QUESTION 3

Page 13-6, footnote 9, states "PG&E's distribution planning process fully accounts for forecast peak loads that are reduced by existing operating DERs that have reduced recorded peak loads."

a. Does this mean that PG&E does not include a forecast of additional solar distributed generation (DG) on its circuits and related impact on peak load? Please explain.

b. Please describe how the impact of future solar DG installations is accounted for in PG&E's analysis.

c. Please provide a sample calculation that demonstrates how PG&E calculates peak load in distribution planning and define each input. Please identify the inputs to the calculation that account for already-installed distributed solar generation and how future distributed solar installations impact the peak load calculation.

   i. If future distributed solar installations do not impact peak load on a circuit, please explain why PG&E believes this to be the correct methodology and provide all studies and workpapers that support PG&E's assertion.

ANSWER 3

a. Beginning with the 2012 annual planning cycle and implementation of Integral Analytics' LoadSEER tool, PG&E's distribution load growth projections have incorporated energy efficiency (EE), demand response (DR), and distribution generation (DG) load impacts in the following ways:

   - Load impacts from existing interconnected DG, (including solar DG and small DG typically considered to be less than 500 kW), from historic DR, and from historic EE measures are embedded in the historic observed peak loads. This historic data, inclusive of the impacts of DG, DR and EE, is used to determine the level of temperature normalized historic peak demand in the LoadSEER geospatial forecasts used and accounted for in PG&E's distribution planning process.

   - To the extent that they are incorporated by PG&E and in the California Energy Commission's adopted California Energy Demand base case peak load forecast, the LoadSEER geospatial forecasts incorporate projected future load impacts due to:

- DG
- EE
- Non-event based DR (such as time of use rates and permanent load shifting)
- Event based DR (such a peak day pricing and SmartRate)

Incorporating EE, DR and DG into the underlying load growth projections ensures DERs are reflected in the need for capacity additions. Note that PG&E considers DERs to be DG as well as EE and DR.

b. See response to a., above.

c. PG&E uses annual recorded peak demand readings at the feeder and bank level as the historic input to LoadSEER. These annual recorded peak demands at the feeder and bank levels include impacts from existing DERs. Future DER is considered as part of the system level California Energy Commission's adopted California Energy Demand base case peak load forecast.

The annual demand peak can be adjusted if necessary to account for abnormal switching configurations that might have occurred during the local peak. Bank and feeder peaks can also be adjusted upward by discounting generation to ensure demand does not exceed capacity if the generation output is not available during peak periods. Adjustments are generally made in the following manner:

- If a feeder or bank has multiple generators connected, then the output from only the largest single unit should be used to increase the recorded peak demand unless there are multiple hydro units, then all units should be considered when adjusting the recorded peak. It is feasible for all hydro generation to be off line during peak due to lack of water.
- Using available Supervisory Control and Data Acquisition (SCADA) data for peak date, time, and load shape for banks and feeders with connected generation, the generation output at the time of the recorded peak is identified. If SCADA data is not available for the bank or feeder, then the bank and feeder load shapes within LoadSEER can be used to determine the time of peak.
- The generator output for the same date and time as the recorded peak of the feeder or bank is used to increase the peak for the potential loss of generation.
- For Solar generation, the adjustment process only applies to systems with output greater than 500 kW. All solar units less than 500kW are considered to reduce peak based on historical performance and are not discounted in forecast. Using the date and time of the recorded peak demand and a solar hourly load shape or output, the solar adjustment to the peak can be determined.

  Example: A solar system of 950 kW of connected PV output is connected to a feeder that has a recorded peak at 6 pm or 18:00 hours. Based on the solar hourly output table below, at 18:00 hours the output is 4% of the PV connected rating.

950 kW X 0.04 = 38 kW

This 38 kW would then be added to the recorded peak of the feeder and bank to which the solar generation is connected, thereby discounting the amount of generation at peak.

Solar hourly output[1]:

July / August Average PV Gen Profile Non-Residential	
Hour	**% Output of Connected Rating**
12:00 am	0%
01:00	0%
02:00	0%
03:00	0%
04:00	0%
05:00	1%
06:00	10%
07:00	28%
08:00	48%
09:00	64%
10:00	75%
11:00	81%
12:00 (noon)	82%
13:00	78%
14:00	69%

1 PV Generation profile developed by PG&E's Distribution Generation Policy and Strategy group for PG&E's Distribution Resources Plan (DRP) filed with the CPUC in July 2015.

15:00	56%
16:00	38%
17:00	19%
18:00	4%
19:00	0%
20:00	0%
21:00	0%
22:00	0%
23:00	0%

If the recorded feeder peak at 5 pm was measured at 10 MW and the bank peak was measured at 25 MW, then the adjusted peak documented in LoadSEER and utilized for forecasting would be:

Feeder: 10.00 MW + 0.038MW = 10.038 MW

Bank: 25.00 MW + 0.038 MW = 25.038 MW

Adding the amount of generation at peak of the largest single unit to the recorded peak effectively discounts the generation of that unit. The adjusted peak as calculated above would be the peak load documented in LoadSEER as the historic demand.

i. Please see the response to 3.a above.

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-006

To: SEIA
Prepared by: James Hodge
Title: Manager
Dated: 03/28/2017

Question 6.3.a:

6.3 Please provide:

a) Total number of PV systems connected to SCE's distribution system with nameplate ratings 500kW or less, and the total capacity of these systems (in CEC-AC MW), as of 12/31/2016.

Response to Question 6.3.a:

The total number of PV systems connected to SCE's distribution system with nameplate ratings 500kW or less as of 12/31/2016 was 210,207. The total capacity of these systems was 1,405.246 MW (in CEC-AC MW).

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-001

To: SEIA; VOTE SOLAR
Prepared by: Christopher Ohlheiser
Title: Engineer
Dated: 02/10/2017

Question 01.21:

1.21 In its response to ORA-SCE-067-TCR Question 22, SCE states that it did not adjust the base load forecast based on the impact of Demand Response (DR) programs. However, page 18 of the *Load Growth Refresher Training,* provided in response to ORA-SCE-066-TCR Question 04, indicates that there are adjustments made for DR. Please clarify this apparent contradiction

Response to Question 01.21:

SCE provided two documents in response to question 4 of ORA-SCE-066-TCR: "ORA-SCE-066-TCR Q4 – Load Growth Training.pdf" and "ORA-SCE-066-TCR Q4 – Starting Point Analysis Training.pdf." Each of these documents describe a different step in the forecasting process. "ORA-SCE-066-TCR Q4 – Starting Point Analysis Training.pdf" describes how SCE analyzes the historic peak and "ORA-SCE-066-TCR Q4 – Load Growth Training.pdf" describes how the load growth forecast is developed.

The overall goal of the starting point analysis is to determine how much load was connected to the distribution system at the time of the peak. Slide 18 of "ORA-SCE-066-TCR Q4 – Starting Point Analysis Training.pdf" is the process SCE uses to adjust the recorded peak to account for any load that was offline during a demand response event. With this load added back in, the adjusted peak reflects the amount of load SCE would have needed to serve if the demand response event was not called. This removes the impact of historical demand response events from SCE's load.

The goal of the development of the load growth forecast is to forecast future load growth and applicable DERs, which would include electric vehicles, dependable PV, and energy efficiency. The document that describes this process, "ORA-SCE-066-TCR Q4 – Load Growth Training.pdf," does not reference demand response, as that is not part of SCE's forecast.

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-001

To: SEIA; VOTE SOLAR
Prepared by: Christopher Ohlheiser
Title: Engineer
Dated: 02/10/2017

Question 01.24:

1.24 SCE's response to ORA-SCE-067-TCR Question 23 states that there are currently no adjustments to load forecasts for storage. How will SCE incorporate the impacts of storage (both standalone storage and PV-with-storage) into future load forecasts and its distribution planning processes?

Response to Question 01.24:

SCE does not currently include energy storage in its distribution forecast due to the uncertainty of the operation of the energy storage device. There are existing DRP proceedings and workshops, such as DRP Track 3, Sub-Track 1: Forecasting and Growth Scenarios, that are determining how to incorporate the impact of all DERs, including energy storage, into the forecast.

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-001

To: SEIA; VOTE SOLAR
Prepared by: Tyson Laggenbauer
Title: Engineer
Dated: 02/10/2017

Question 01.22:

1.22 Please explain why SCE believes DR to be non-dependable, as described in SCE's response to ORA-SCE-068-TCR Question 30

Response to Question 01.22:

Demand response events are initiated by CAISO at unpredictable times throughout the year, not guaranteeing that a future demand response event will be called on the peak day for the asset impacted by a past demand response event. When a demand response event is called, the amount of load reduction is unpredictable. Without direct load control, customers can opt out of the demand response event and not participate, continuing to consume load. There also may be scenarios where customers are not consuming load during the demand response event which would not reduce any load on distribution equipment. In addition, customers presently enrolled in a demand response program are not guaranteed to continue participation in the future.

SCE does not presently have the ability to dispatch demand response at a local level to meet distribution needs; demand response events can presently only be dispatched at the wholesale level. New DR programs or contracts need to be developed in order to meet distribution needs and be considered dependable. SCE is researching how demand response can be included in future forecasts. Part of the Distribution Resources Plan proceeding is focusing on Forecasting and Growth Scenarios. That proceeding analyzes how DER growth is included in the distribution planning forecast including demand response.

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-001

To: SEIA; VOTE SOLAR
Prepared by: Christopher Ohlheiser
Title: Engineer
Dated: 02/10/2017

Question 01.24:

1.24 SCE's response to ORA-SCE-067-TCR Question 23 states that there are currently no adjustments to load forecasts for storage. How will SCE incorporate the impacts of storage (both standalone storage and PV-with-storage) into future load forecasts and its distribution planning processes?

Response to Question 01.24:

SCE does not currently include energy storage in its distribution forecast due to the uncertainty of the operation of the energy storage device. There are existing DRP proceedings and workshops, such as DRP Track 3, Sub-Track 1: Forecasting and Growth Scenarios, that are determining how to incorporate the impact of all DERs, including energy storage, into the forecast.

Southern California Edison
2018 GRC A.16-09-001

DATA REQUEST SET SEIA-Vote Solar-SCE-002

To: VOTE SOLAR; SEIA
Prepared by: Eric Nunnally
Title: Engineering Manager
Dated: 03/01/2017

Question 02.6:

SCE's workpaper entitled "Distribution Automation & Circuit Tie Deployment Plan" at p. 65 states, " Location-specific demand response would also serve as a flexible resource when not responding to wholesale market signals. When dispatched by the distribution system operators, performance is considered more predictable and dependable, and can be incorporated into the planning process." Please describe all such location-specific demand response programs currently offered or planned by SCE, the locations of each program including substation names, and the expected demand reduction from each program in years 2018- 2020.

Response to Question 02.6:

SCE does not have this information in a readily available format to provide for this request. SCE does not have the ability to dispatch demand response programs/resources at a granular distribution level today. This capability would be obtained with the implementation of a GMS, specifically with DERMS functionality. Once a GMS was implemented such that we had the capability of distribution level, location-specific control of demand response, then the statement made in workpapers on page 65 can be realized.