**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE**

**STATE OF CALIFORNIA**

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| Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. | Rulemaking 14-08-013<br>(Filed August 14, 2014) |
| And Related Matters. | Application 15-07-002<br>Application 15-07-003<br>Application 15-07-006 |

**(NOT CONSOLIDATED)**

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| In the Matter of the Application of PacifiCorp (U 901-E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769. | Application 15-07-005<br>(Filed July 1, 2015) |
| And Related Matters. | Application 15-07-007<br>Application 15-07-008 |

**SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E)**
**DEMONSTRATION PROJECTS A AND B FINAL REPORTS**

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Dated: December 23, 2016

Pursuant to the May 2, 2016 *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B* ("May ACR"),[1] and the August 23, 2016 *Assigned Commissioner's Ruling Granting the Joint Motion of San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas & Electric Company to Modify Specific Portions of 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* ("August ACR"), Southern California Edison Company ("SCE") respectfully submits its (1) Demonstration Project A Final Report and (2) Demonstration Project B Final Report, attached as Appendices A and B, respectively.

## I.

## INTRODUCTION AND PROCEDURAL BACKGROUND REGARDING FINAL REPORTS

On August 20, 2014, the California Public Utilities Commission ("Commission") initiated Rulemaking (R.)14-08-013 ("DRP OIR") to establish policies, procedures, and rules to guide California investor-owned utilities ("Utilities") in developing their Distribution Resources Plan (DRP) Proposals. The Utilities were required to file individual DRPs by July 1, 2015 in compliance with California Public Utilities Code Section 769. On February 6, 2015, the Commission issued an Assigned Commissioner's Ruling, setting forth detailed guidance ("Final Guidance") for Utilities to follow in their Section 769 compliance filing. The Final Guidance directed the Utilities, among other requirements, to: (a) develop a specification for a

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[1] R.14-08-013, *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B*, May 2, 2016, Appendix A at pp. 21, 37; R.14-08-013, *Assigned Commissioner's Ruling Granting the Joint Motion of San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas & Electric Company to Modify Specific Portions of 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 Southern California Edison Company*, August 23, 2016, Appendix A at pp. 21, 37.

demonstration project (*i.e.*, “Demo A”) where the Utilities’ Commission-approved Integration Capacity Analysis (“ICA”) methodology is applied to all line sections or nodes within a Distribution Planning Area (“DPA”) and (b) develop a specification for a demonstration project (*i.e.*, “Demo B”) where the Utilities’ Commission-approved Locational Net Benefit Analysis (“LNBA”) methodology is performed for one DPA. On July 1, 2015, SCE filed its DRP, which included proposals for Demo A and Demo B.

On May 2, 2016, the Assigned Commissioner issued the May ACR, approving ICA and LNBA methodologies and requirements on an interim basis for use in Demos A and B. The May ACR also directed the Utilities to prepare implementation plans for their respective Demos A and B consistent with a series of prescriptive requirements for these demonstration projects that were outlined in Appendix A to the May ACR. On June 16, 2016, SCE filed implementation plans for Demo A and Demo B. On August 23, 2016, the Assigned Commissioner issued the August ACR, modifying and adding certain requirements for Demos A and B.

The May ACR also established an ICA Working Group and a LNBA Working Group. The ICA Working Group was established to “monitor and provide consultation to the IOUs on the execution of Demonstration Project A and further refinements to ICA methods.”[2] The LNBA Working Group was established to “monitor and provide consultation to the IOUs on the execution of Demonstration Project B and further refinements to LNBA methods.”[3]

Pursuant to the May and August ACR[4] and ALJ Mason’s November 29, 2016 Email Ruling,[5] both the ICA and LNBA Working Groups are required to submit a Final Report by

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[2] May CR, at p. 18.
[3] May ACR, at p. 34.
[4] May ACR, at pp. 21, 37; August ACR, at pp. 21, 37.
[5] *E-Mail Ruling Granting San Diego Gas & Electric Company/Southern California Edison Company/Pacific Gas and Electric Company Joint Motion For One Month Extension To Submit Their Integration Capacity Analysis Work Group And Locational Net Benefits Analysis Working Group Final Reports*, (“November 29, 2016 Email Ruling”), November 29, 2016.

January 31, 2017. The May ACR also directed that "Energy Division may provide further direction regarding the content and format of the report."[6] Per the Joint Utilities' Joint Motion for extension of time granted by the ALJ's November 29, 2016 Email Ruling, SCE has prepared and is filing its Final Reports for Demos A and B at this time in order to provide the Working Groups with sufficient information and support for their Final Reports due January 31, 2017.

Attached to this motion as Appendix A is SCE's Demo A Final Report. Attached to this motion as Appendix B is SCE's Demo B Final Report.

## II.

## CONCLUSION

SCE respectfully submits these final reports pursuant to the requirements of the May ACR and August ACR.

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[6] *See* May ACR, at pp. 21, 37; August ACR, at pp. 21, 37.

# Appendix A

## Demonstration Project A Final Report

# Southern California Edison Distribution Resources Plan Demonstration Project A

Enhanced Integration Capacity Analysis Final Report

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# 1. Executive Summary

The expected high levels of distributed energy resources (DERs) on Southern California Edison's (SCE) distribution system will have significant impacts on all critical distribution system functions. These include: maintaining distribution system electrical components within thermal limits, maintaining power quality within applicable industry standards, and maintaining the necessary level of protection to provide safe and reliable electrical service to customers. The determination of the maximum amount of DERs that can be connected without adversely impacting SCE's distribution system functions involves rigorous engineering analysis and review. This extensive and thorough process is referred to as the Integration Capacity Analysis (ICA)[1].

SCE supports the Commission's goal of integrating DERs into the utilities' distribution planning, operations and investment processes. SCE, in its recently released whitepaper "The Emerging Clean Energy Economy,[2]" outlined a similar vision to accelerate the transition to a clean, reliable energy future that includes a high penetration of DERs. SCE's whitepaper describes the "plug-and-play" future that SCE envisions for the electric grid, by facilitating customer choice of new technologies, creating opportunities for DERs to provides grid services, and modernizing the grid to ease integration and optimization of DERs. Realizing this shared vision of a modernized, digital power system will take a significant effort from all stakeholders over many years, and efforts such as Demonstration Project (Demo) A are important steps towards achieving our common objectives.

Within this final report, SCE demonstrates its compliance with the Assigned Commissioner's Ruling (ACR)[3] for Demo A. The ACR requires the demonstration of a fully-dynamic analysis which would determine the results of the ICA at nodes or line sections within the distribution system based on limiting categories of thermal, power quality, voltage, protection, safety and reliability. The ACR requires at a minimum:

1. The demonstration is to be performed in two distinct Distribution Planning Areas (DPAs);
2. The demonstration is to employ two different methodologies of calculating the ICA values using:
    a. A scenario which limits power flow analysis to ensure power does not flow towards the transmission system beyond the distribution substation bus;

[1] Synonymous with "Hosting Capacity Analysis. "
[2] SCE's whitepaper can be found at: http://www.edison.com/content/dam/eix/documents/our-perspective/der-dso-white-paper-final-201609.pdf
[3] R.14-08-013, *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B*, May 2, 2016, Appendix A ("May ACR"). This May ACR was subsequently updated by the Commission. *See* R.14-08-013, *Assigned Commissioner's Ruling Granting the Joint Motion of San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas & Electric Company to Modify Specific Portions of 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 Southern California Edison Company*, August 23, 2016 ("August ACR" or "ACR").

b. A scenario which determines the technical maximum amount of interconnected DERs that the system is capable of accommodating irrespective of power flow direction;
3. New layers to be added to existing ICA maps to convey the results; and
4. The outcome of the analysis must be shared on a website accessible to the public.

SCE selected its DPAs to represent the wide variety of distribution systems within SCE's diverse service territory. The first DPA, a segment of Orange County, was used to represent the typical urban service area while the second DPA, a segment in Tulare County, was selected to represent a typical rural service area. Together the two DPAs encompassed eight distribution substations and 82 distribution feeders serving a representative mixture of residential, commercial, industrial, and agricultural customers. Through analysis of these two DPAs, SCE demonstrated that the characteristics of local distribution systems are significant factors which dictate the level of DERs that can be interconnected to the distribution grid without adversely affecting the critical distribution system components.

As also required by the ACR, SCE utilized two methodologies of calculating the ICA limits based on 576 hours over a 12-month period, composed of one day per month of typical high-load conditions and one day per month of typical light-load conditions. The first methodology, referred to as the ***Streamlined Method,*** is based on the Baseline Method outlined in the ACR, with additional functionality[4] included by SCE to improve the accuracy of the results. This method performs one power flow simulation for each hour and then extracts quantities from the power flow simulation and inserts them into the streamlined equations to determine the ICA limitations for each of the limiting categories. The second methodology, referred to as ***Iterative Method,*** utilizes iterative power flow simulations to determine the levels of DERs which may be interconnected at each node or line section without exceeding each of the limiting categories. This method parallels what is used in SCE's current interconnection study process, which evaluates impacts to the distribution system for generation interconnection applications.

To present the results, SCE produced and made available the 576 hourly ICA values using a "technology-agnostic uniform generation and uniform load" approach. This approach generates ICA values that are independent of the type of DER technology. To allow users of the data to understand specific technology limitations, SCE also made available an ICA translator which can be used to translate the technology-agnostic uniform generation or load ICA values into a desired, specific technology or portfolio of technologies.

In collaboration and agreement among the IOUs, the steady state voltage (SSV) limitation was added to the Baseline Method which improved the accuracy of the Streamlined Method ICA results. *The Streamlined Method* performs one power flow simulation per one hour of analysis to extract initial conditions—such as loading, voltage, and short-circuit duty—to input into external equations within SCE's created Python scripts. This method yields results quickly, but for areas with voltage regulation schemes (e.g., voltage regulators and load tap changers and capacitors) that are required for areas that are distant from the substation, or for those

4 In consensus with the other IOUs, SCE, PG&E and SDG&E added the Steady State Voltage criteria.

systems that have low short-circuit duty values, this method may over or under-estimate the value of ICA since it may not detect violations of voltage or thermal limitations accurately. The primary value of the *Streamlined Method* to be that it is highly efficient in terms of the computational time required to produce ICA values. For Demo A, the average time to complete the 576 hourly ICA calculations using this method for one single average size feeder was approximately 2 minutes.

In contrast, the *Iterative* M*ethod* performs multiple power flow simulations with varying levels of DERs connected at the nodes. Each of SCE's distribution feeders has on average over 500 nodes. With multiple power flow simulations required per node, thousands of simulations for each feeder are needed, which significantly increases computational time. The primary value of this method to be that it produces the most accurate results that could be applied more seamlessly in the interconnection process. For Demo A, the average time to complete the 576 hourly ICA calculations using this method for a single feeder was approximately 23 minutes.[5]

Since the *Iterative Method* uses calculation methods that are equivalent to those used in SCE's interconnection study process, this method derives results that SCE considers to be more accurate, but take considerable time to produce. Though the *Streamlined Method* achieves results more quickly, the level of accuracy is highly dependent on the complexity of the distribution system, and, in some cases, yields sub-optimal ICA results that would require further study during interconnection.

Through this demonstration, SCE strived to find the proper balance of accuracy of results and computational time requirements, to produce meaningful ICA values that would be useful for near-term use-cases while also allowing for continued refinements of the methodologies and calculations for long-term applications. Long-term, more complex ICA applications would include the applicability of smart inverters and transmission-level evaluations. The most immediate use of the ICA values would be in expediting the interconnection process through modifications of SCE's Rule 21 tariff filed with the California Public Utility Commission. Other likely use cases include the application of ICA information by SCE in its annual planning processes to aid in forecast development.

In recognition of the benefits that each of the two ICA methodologies provide and of what is needed in the near- and long-term, SCE proposes that a *Blended ICA Method* should be adopted for initial implementation of ICA across the SCE service territory. This method would use the *Iterative Method* on the typical 24-hour, light-load day in an annual period while developing a full 576 hourly ICA utilizing the *Streamlined Method*. SCE believes this blended approach would establish a solid baseline for the development of a more complex, long-term ICA analysis.

The *Blended ICA Method* would employ the *Iterative Method* to produce ICA values for a 24-hour light-load. This yields the necessary information required under the existing Rule 21 process, and allows the ICA produced by the *Iterative Method* to provide information that will

[5] It is projected that with increased computational resources and increased efficiency in data management, the processing times for the two methods may significantly increase.

improve the existing interconnection process. As smart inverters become operational, the use of the *Iterative Method* would be refined to maximize the ability of the distribution system to accept higher levels of DERs that implement smart-inverter technology. Equally important in SCE's proposed *Blended ICA Method*, is the use of the *Streamlined Method* to provide information necessary for various use cases where it would be overly burdensome if the *Iterative Method* was used. For instance, the *Streamlined Method* could be used to produce 576 hourly profiles which could be used for planning purposes and to produce technology-specific ICA. The use of both methods as part of the *Blended ICA Method*, with each performing a specific analysis based on strengths of each method, will result in the appropriate balance of computational accuracy and time.

SCE believes that as ICA calculation methodologies continue to evolve, as tools become more effective, and as network models become more accurate through use of enhanced SCADA data, the efficiency of producing the ICA values and the accuracy of the ICA values will increase. Therefore, SCE recommends that for the initial phases of ICA, the proposed ***Blended ICA Method*** should be adopted with the understanding that continuous improvements will occur based on technology improvements, tariff modifications, and improvements in network models.

# 2. Background and Objectives

## 2.1. DRP and Demo A Overview

As described in the original Distribution Resources Plan (DRP) Guidance, the purpose of Demo A is to demonstrate a dynamic[6] Integration Capacity Analysis (ICA) to determine the integration capacity on the distribution network down to a line section or node level within a selected Distribution Planning Areas.[7] To this end, the May ACR was issued on May 2, 2016, instructing the IOUs to implement what the CPUC referred to as modified ICA methodology in Demonstration A which was based on the methodologies proposed by the IOUs in their DRP filings. After discussion and concurrence with the ICA Working Group (ICAWG), the IOUs filed a joint motion requesting modification to the May ACR. On August 23, 2016, the Commission issued an Assigned Commissioner's Ruling (August ACR) granting the joint motion of IOUs to modify specific portions of the May ACR and updating the Demo A requirements. For purposes of this report, the May and August ACRs are referred to as the ACRs.

The ICA methodology utilized by SCE in the Demo A project was implemented to meet the requirements of the modified Baseline Method as specified in the ACR, with enhancements to increase the usability and accuracy of the results. This section describe how these requirements are met.

**The Baseline Method must:**

- Establish distribution system level of granularity.
- Model and extract power system data.
- Evaluate power system criterion to determine DER capacity.
- Calculate ICA results and display on online map.

Below, SCE describes how each of these steps is incorporated into the Demo A project.

**Baseline Method Steps**

1) Establish distribution system level of granularity.
    - In Demo A, SCE performed the ICA analysis down to all nodes[8] and line sections on all of the feeders within the two Demonstration Planning Areas (DPAs).
2) Model and extract power system data.
    - A Power Flow Analysis Tool was utilized to create geospatial feeder models to analyze all the nodes on the primary distribution feeders within the Demo A DPAs.
    - A Load Forecasting Analysis Tool was utilized for forecasting and modeling of load profiles to the proper hourly granularity.
3) Evaluate power system criterion to determine DER capacity.

[6] Dynamic in this Demo refers to performing hourly analysis

[7] Assigned Commissioner's Ruling on Guidance for Public Utility's Code Section 769 – Distribution Resource Planning

[8] Nodes are electrical connection points in the distribution network model

- The four major criteria of Thermal, Protection, Power Quality/Voltage, and Safety/Reliability are considered in the analysis by performing power flow and fault flow analysis.

4) Calculate ICA results and display on online maps.
   - Results from different layers of the system within the Demo A service area (i.e. line section, substation transformer) were extracted from the analysis and published on SCE's online Distributed Energy Resource Interconnection Map (DERiM).

## 2.2. CPUC Requirements

The ACR identified the nine functional requirements described below.

1. Quantify the capability of the distribution system to integrate DERs.
2. Utilize a common methodology across all IOUs.
3. Perform analysis on different types of DERs.
4. Perform analysis at the line section or nodal level on the primary distribution system
5. Include in the analysis the thermal ratings, protection limits, power quality (including voltage), and safety standards.
6. Publish the results via online maps.
7. Utilize time-series models.
8. Avoid heuristic approaches, where possible.
9. Demonstrate dynamic ICA using two DER scenarios including 1) no power backflow at the substation bus, and 2) maximum DER capacity irrespective of power flow direction.

### Modifications Included in the Baseline Method

1. Quantify the capability of the distribution system within the DPAs to integrate DER
   a. Electric distribution feeders (i.e., circuits) were modeled in the power flow software with individual capacitor bank devices that contribute reactive power to the feeder.
   b. Effects of load-modifying resources (e.g., energy efficiency, demand response) on the ICA can be explored in two ways. One method is to examine the "net" loading effect of load-modifying resources which will change the loading conditions under which ICA is calculated. The second is by considering these load modifying resources as a virtual generator directly analyzed with ICA. As an initial step, the ICA used the first approach described above, with consideration given to the input of the ICAWG as part of long-term ICA efforts.
   c. Assumptions used in Demo A are provided in the appropriate sections of this report to help inform the ICAWG and interested stakeholders on how ICA is considering distribution system conditions and DER parameters.
2. Utilize a Common Methodology Across all IOUs
   a. Through comparative assessment and coordination with the ICAWG, the three IOUs worked together to develop more consistency in ICA calculation methodologies as required in the ACRs. This included, but is not limited to:

- Application of operational flexibility ICA limit.
- Utilization of the 10% as a flag in the Streamlined Method for the protection limit.
- 1.2 per unit (p.u.) short-circuit contribution for inverter-based technology.

3. Perform analysis on different types of DERs.
   a. The ACRs outlined a set of 'typical or "baseline" DER profiles to consider in the analysis. In discussions with the ICAWG, the IOUs settled on a method to analyze the baseline portfolios using computational efficiency improvements.
   b. The IOUs also provided "agnostic" ICA values that can be used by DER providers to analyze other DER portfolio combinations.
   c. Through agreement of the ICAWG, an "ICA translator" was made available for users to determine the ICA values for different types of DERs.
4. Granularity of ICA in distribution system to be at the line section or node.
   a. The granularity of the ICA was performed at a line section and/or node level on the primary distribution system, as per the original guidance and the ACRs. This means that ICA was analyzed for the high-voltage side (between 4 and 21 kilovolts (kV)) of the distribution system within the DPAs. The scope of the analysis did not include the service transformers or secondary service to customer premises.
5. The analysis included the limitations based on thermal ratings, protection limits, power quality (including voltage), and safety standards.
   a. Four major criteria of thermal, protection, power quality/voltage, and safety/reliability were considered and analyzed. The demo project included the components outlined inTable 2-4 of the ACR.
   b. Protection impacts and limits were evaluated by the IOUs to determine where increased consistency can be achieved. For instance, exploring evaluation of both short circuit capability and reduction of reach versus IOUs evaluating only one or the other.
   c. Included in this report is the identification of any federal, state, and industry standards embedded within the ICA criterion.
6. Publish the results via online maps.
   a. Currently the ICA results of the IOUs are published in coordination with or directly in their respective Renewable Auction Mechanism (RAM) maps. ICA results and load profiles are also published and available on the Commission's DRP webpage. One of the major objectives of this demo was to gain further alignment of the online maps across IOUs. The IOUs, in conjunction with ICAWG coordination and input, were able to increase consistency and effectiveness of the data displayed on the maps. Discussions regarding the format and mechanism for downloading the maps were held in coordination with the ICAWG.
   b. The information originally provided in the RAM map has some areas of overlap with the DRP ICA data. The intention is that the original data of RAM is given as the default information and that ICA data is properly coordinated with it. This will

include reviewing and reducing overlap of new data and ensuring that the interface is user-friendly and effective for DER developers.

7. Use time-series or dynamic models.
    a. The demo project analyzed a 576-hour load profile as determined by peak and minimum 24-hour profiles for each month as well as dynamic power flow interactions with time-dependent components of the system. This is a major application of exploration of various approaches such as iterative simulations and streamlined calculations.
8. Avoid heuristic approaches, where possible .
    a. The IOUs made every effort to eliminate heuristic approaches in favor of dynamic analysis throughout Demo A. Where heuristic approaches were used (e.g., operational flexibility), those methods were determined to be the most reasonable approach using current tools.
9. Demonstrate dynamic ICA using two DER scenarios including 1) no power backflow at the substation bus, and 2) maximum DER capacity irrespective of power flow direction.
    a. The IOUs evaluated the distribution feeders in Demo A under a scenario which did not allow power to flow into the substation from the distribution feeders and a scenario which allowed power to flow into the substation from the distribution feeders until each of the criteria limit was reached.

Based on the ACR and ICAWG discussions, there were limitations identified regarding what could be analyzed within the Demo A Project timeframe. These limitations include the ability to perform analysis on secondary voltage services and analysis on high-voltage transmission and subtransmission systems typically greater than 50 kV. Analysis for these levels of the system should be explored as a long-term item in the ICAWG, but for the short-term it was determined to be out-of-scope for this demonstration project.

## 2.3. Deliverables

Consistent with the direction of the ACR and to support the ICAWG, SCE prepared this Final Report to summarize the Demo A project activities and to provide documentation of the ICA methodologies and results. In addition, the resulting ICA data will be made publicly available using online maps and in a downloadable format. The maps, associated materials, and download formats shall be consistent across all IOUs and should be clearly explained.

In this final report, SCE describes the objectives, methodologies, results and learnings of Demo A. All of the pertinent data and maps are available for download at the following locations:

1. DERiM Web Map: http://on.sce.com/derim
2. DERiM Web App (load profiles): http://on.sce.com/derimwebapp
3. Expanded DERiM User Guide: http://on.sce.com/derimguide
4. DRP Demo Results Library: http://on.sce.com/drpdemos

# 3. Selected Distribution Planning Areas

## 3.1. General Description

Per the ACRs, SCE selected two DPAs that represent a broad range of physical and electrical conditions within SCE's distribution system. This is beneficial as it can increase the ICAWG's understanding of the DER integration capacity within a system composed of multiple, different electrical and physical characteristics. The selected DPAs are the Johanna DPA and the Rector DPA, an urban and a rural DPA, respectively.

SCE's service territory covers a wide area varying in electrical and physical characteristics. In a simplified manner, the counties along the coast, such as Los Angeles, Ventura, Orange, and Santa Barbara are similar: highly populated and typically served with a large number of short distribution feeders. In comparison, areas to the east like Kern, Tulare, San Bernardino, and Riverside counties are lightly populated and served by fewer, longer feeders.

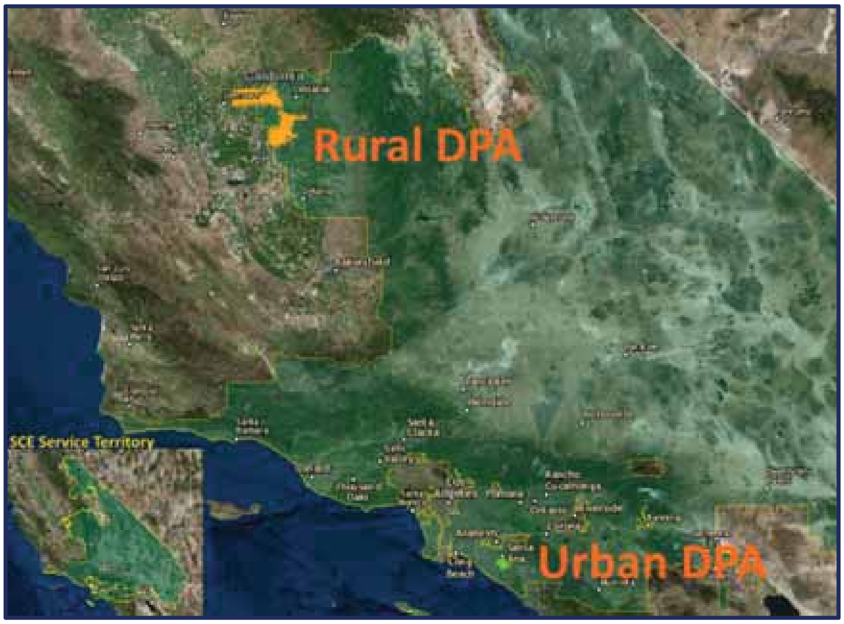



FIGURE 1: GEOGRAPHIC LOCATIONS OF DPAS

Figure 1 presents the geographic locations of the two Demo A DPAs within SCE's territory with the orange area showing the rural DPA and the bright green area showing the urban DPA[9]. Figure 2 shows the satellite view of the DPAs. The Johanna DPA is a dense, urban area located in Orange County that serves a mixture of residential, commercial, and light industrial loads. The Johanna DPA is composed of three 66/12KV substations, one 12/4KV substation, 32 12KV distribution feeders and five 4.16KV feeders; it is part of SCE's Preferred Resources Pilot (PRP).[10] The Johanna DPA serves approximately 79.0% residential customers, 16.9% commercial customers, 2.7% industrial customers, 0.4% agricultural customers, and 1.0% other customers. The Rector DPA is a typical rural service area located in the Central Valley and is made up of residential, commercial, and agricultural load impacted by recent drought

[9] This map is also available on SCE's DRiM site located at http://on.sce.com/derim
[10] www.edison.com/home/innovation/preferred-resources-pilot.html

conditions. The Rector DPA serves a geographical area more than six times the size and twice the number of customers compared to the Johanna DPA. The Rector DPA is composed of five 66/12KV substations and 45 12KV distribution feeders and it serves approximately 83.2% residential customers, 9.9% commercial customers, 0.7% industrial customers 5.3% agricultural customers, and 0.9% other customers.

The urban DPA consists of Johanna 66/12kV, Camden 66/12kV, Fairview 66/12kV and Edinger 12/4.16kV substations. These four substations are served from the Johanna 220/66kV substation and encompass approximately half of what SCE refers to as the Johanna A-System. The rural DPA consists of Goshen 66/12kV, Hanford 66/12kV, Mascot 66/12kV, Octol 66/12kV and Tulare 66/12kV Substations. All five substations are served from the Rector 220/66kV substation and encompass approximately half of what SCE refers to as the Rector A-System.


FIGURE 2: SATELLITE VIEW OF DPAS (TOP: URBAN DPA; BOTTOM: RURAL DPA)

Table 1 lists some system characteristics of the two selected DPAs to illustrate that the DPA selection covers a broad range of physical and electrical characteristics within SCE's service territory.

TABLE 1: OVERVIEW OF DPA CHARACTERISTICS

| | Urban DPA | Rural DPA |
|---|---|---|
| **Area** | Orange County | Central Valley |
| **Service Area Size** | 18 $mi^2$ | 120 $mi^2$ |
| **No. Feeders** | 38[11] | 44[12] |
| **No. Customers** | 25,100 | 49,700 |
| **2016 Projected Load** | 217 MVA | 314 MVA |
| **No. Service transformers** | 2,375 | 9,617 |
| **Load types** | Mixture of residential, commercial, and light Industrial loads | Mixture of residential and commercial, with significant agricultural loads |
| **Substations** | Johanna 66/12, Camden 66/12, Fairview 66/12, Edinger 12/4.16 | Goshen 66/12, Hanford 66/12, Mascot 66/12, Octol 66/12, Tulare 66/12 |
| **Special Notes:** | Within PRP region | Load growth driven by drought conditions |

## 3.2. DPA Characteristics Comparison

Recent industry research and studies have shown that some system parameters, such as feeder length, electrical resistance, and loading level, are essential elements in determining DER integration capacity limitations. Therefore, it is important to consider those parameters in the DPA selection so that the selected DPAs cover a wide range of system characteristics that are relevant to ICA methodology and results.

### 3.2.1. Feeder Length

Figure 3 shows a representation of the average feeder length for the Demo A DPAs in comparison to system-wide average lengths. As depicted in Figure 3, the average distribution feeder length in SCE's service area is approximately 15.3 conductor miles. In comparison, the average feeder length in the urban DPA is 8.3 conductor miles while the average feeder length in the rural DPA is 25.9 conductor miles.

[11] Includes five 4.16kV circuits (Edinger 12/4kV Substation)
[12] The 4KV circuits in Tulare and Hanford substations have been completely cutover, so they are not included in the Demo A study.

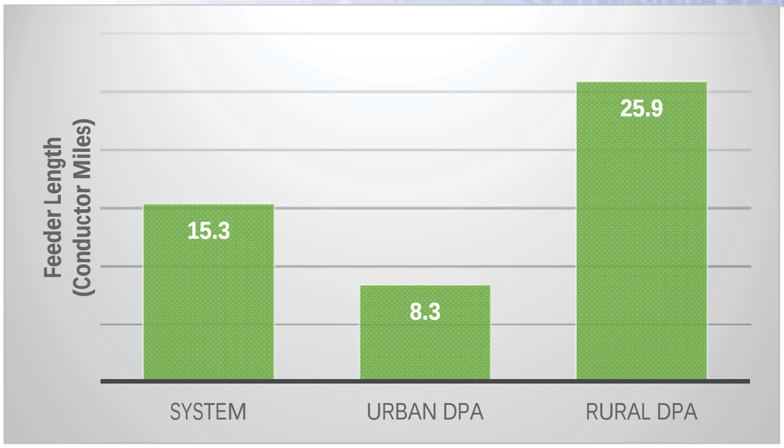



FIGURE 3: COMPARISONS OF THE AVERAGE FEEDER LENGTH

### 3.2.2. Maximum 3-Phase Resistance

3-phase resistance refers to the electrical resistance of the three phase line sections and it's an important element in the calculation of ICA. As discussed in the previous section, the DER integration capacity at a node generally decreases as the resistance from the substation to the node increases. The maximum resistance of 3-phase sections represents the furthest 3-phase electrical point on a feeder in Demo A. Figure 4 shows the average values of maximum 3-phase resistance of the feeders in the selected DPAs and the system average maximum 3-phase resistance value. The average value of the maximum 3-phase resistance for all the feeders in SCE's system is 1.7 Ohms. In comparison, the average value of the maximum 3-phase resistance for feeders in the urban DPA is 0.7 Ohms while the average value of the maximum 3-phase resistance for feeders in the rural DPA is 3.6 Ohms.

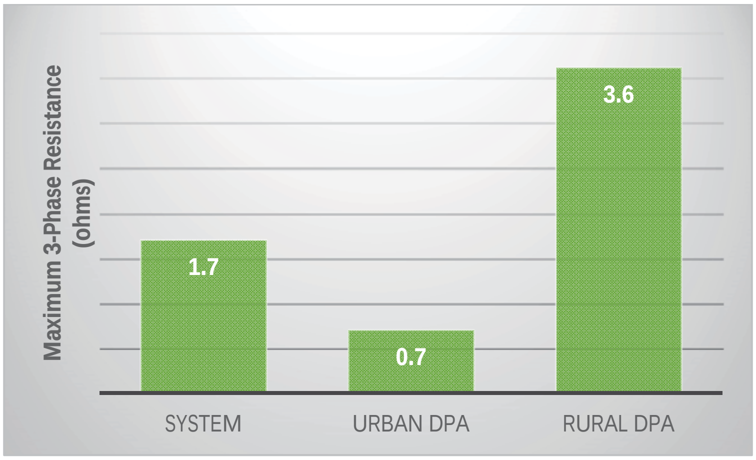



FIGURE 4: COMPARISONS OF THE AVERAGE MAXIMUM 3-PHASE RESISTANCE

### 3.2.3. Three-Phase End-of-Line Short Circuit Current

The 3-phase, end-of-line short circuit current affects the feeder protection scheme and represents the strength of the system to minimize voltage fluctuation due to changes in loading. Figure 5 depicts the average 3-phase, end-of-line short circuit current of the feeders in the selected DPAs and the system average. The average value of the 3-phase, end-of-line short circuit current for all the feeders in SCE's system is approximately 3,100 Amps. In comparison, the average value of the 3-phase, end-of-line short circuit current for feeders in the urban DPA is 5,100 Amps while the average value of the 3-phase end-of-line short circuit current for feeders in the rural DPA is 2,000 Amps.

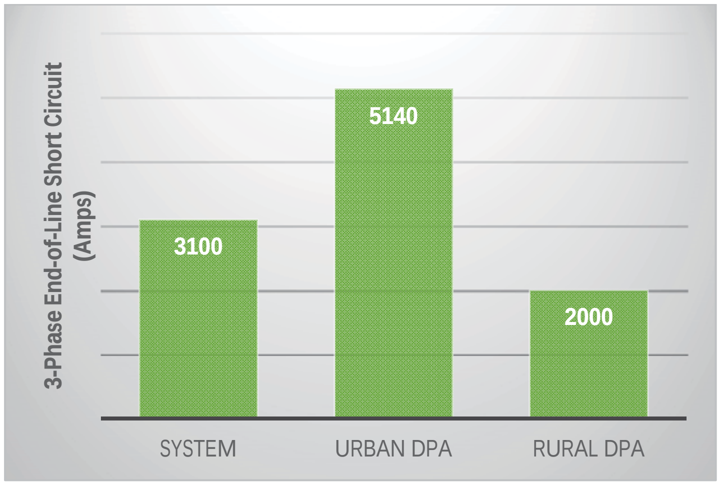



FIGURE 5: COMPARISONS OF THE AVERAGE END-OF-LINE SHORT CIRCUIT CURRENT

### 3.2.4. Load Profile

The feeder load profile has a significant impact on the ability of the feeder to integrate DERs. Most SCE feeders are summer peaking, with the months of July thru September being the typical peak months. However, not all feeders exhibit similar load profiles. For instance, as depicted in Figure 6, the typical urban DPA feeders have a January hourly load profile that is less variable than the typical rural DPA feeders. In Figure 7, it can be observed that the typical urban feeder load profile has a longer periods of high load (longer thick blue bars) each day as compared to the typical rural feeder load profile, their peaks are generally similar.

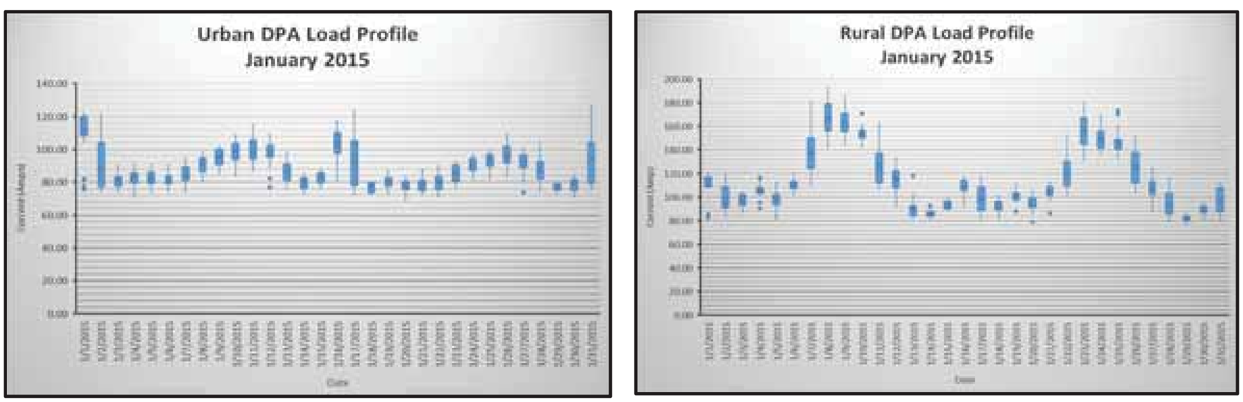



FIGURE 6: COMPARISONS OF JANUARY LOAD PROFILES

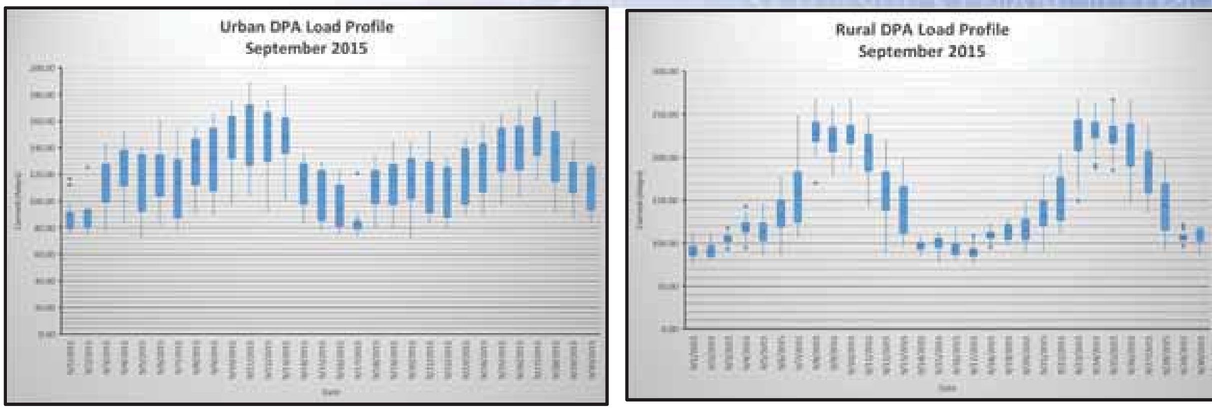



FIGURE 7: COMPARISONS OF SEPTEMBER LOAD PROFILES

# 4. Methodology

## 4.1. General Description

This chapter describes the methodologies implemented in Demo A. Demo A is a developmental step towards the IOUs' final proposals for a common ICA methodology. The goal is to propose a solution that can be used to update the DER integration capacity and publish the results to the public at regular intervals. Consistent with the ACR requirements, the modified Baseline Method used in the Demo A is described below in four general steps:

- Establish distribution system level of granularity;
- Model and extract power system data;
- Evaluate power system criterion to determine DER capacity;
- Calculate ICA results and display on online map.

Figure 8 illustrates the general ICA process. After the system model data and load data are extracted from various databases, the distribution feeder models are developed in the power flow analysis tool[13]. The applicable power system criteria are examined based on 1) pre-defined equations referred to as the Streamlined Method and 2) iterative power flow simulations referred to as the Iterative Method. Each of these two methods identify the maximum DER integration capacity at each node. The DER integration capacity for each criterion is calculated independently and the most limiting value is used to establish the final integration capacity limit. In addition to the line section and node analysis, the feeder level ICA and substation level ICA are also performed. The detailed ICA results are made publicly available online and in a downloadable format.

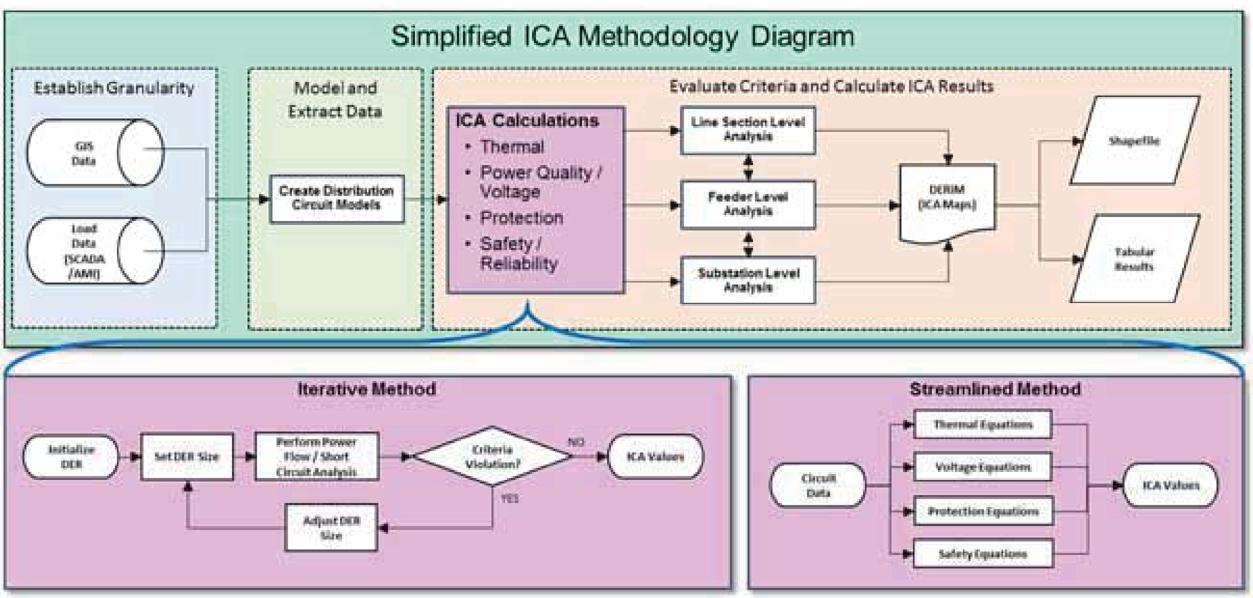



FIGURE 8: ICA PROCESS DIAGRAM

[13] SCE utilizes CYME as the power flow modeling tool.

### 4.1.1. Streamlined Method

The Streamlined Method uses a set of equations and algorithms to evaluate power system criteria at each node on the distribution system. SCE developed Python-based scripts to perform the calculations. These scripts automated the ICA process and performed basic semantics validations. The Streamlined Method first performs power flow and short-circuit duty simulations at each hour to acquire the initial conditions of the feeder based on that hour loading and voltage conditions. The data which is acquired after the simulations is used in the streamlined calculations. The data acquired are electrical characteristics such as thermal ratings for all 3-phase conductors in the feeder, resistance of each 3-phase line section, line-neutral voltages at each node, current, and fault duties. The Streamlined Method then evaluates the full set of criteria, including thermal, voltage, protection, and safety limits independently to estimate the maximum integration capacity at a given node on each of the feeders within the DPAs. The Streamlined Method may not capture some of the dynamic effects of DERs on complex feeders or distribution systems with voltage regulation or complex protection schemes, as it only performs one power flow to extract data. However, the ability to utilize these simpler equations and algorithms within a database can enable faster computations on large datasets.

### 4.1.2. Iterative Method

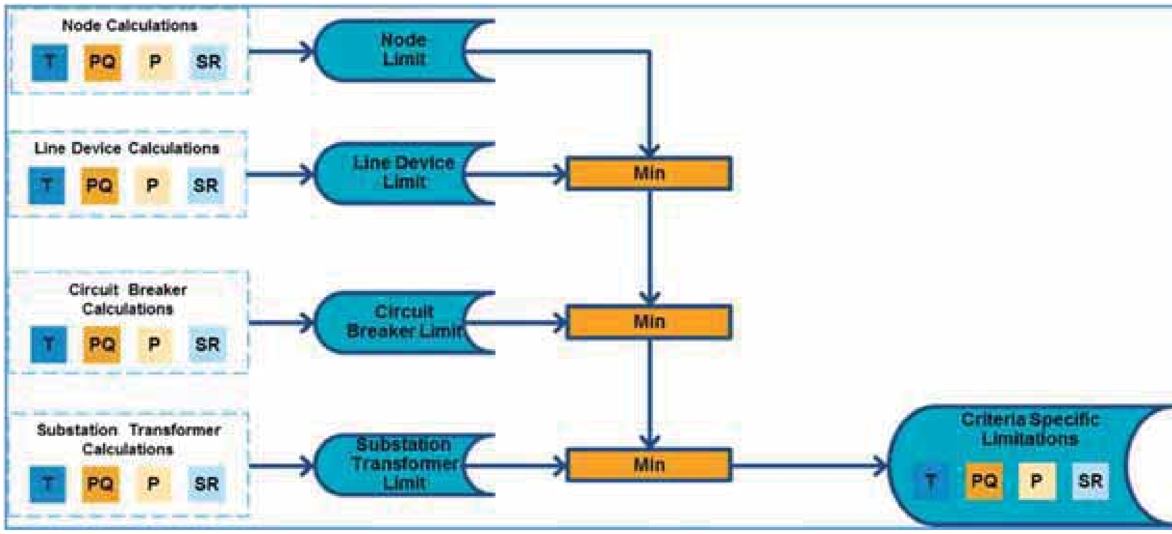
The Iterative Method performs iterative power flow simulation at each node on the distribution system within the Demo A DPAs. Using this method, varying levels of DER are simulated at each node independently with power flow simulations performed to determine the maximum level of DER that can interconnect at these locations without exceeding thermal and voltage limits. In addition to the power flow simulations, which are used primarily to evaluate thermal and steady state voltage conditions, a fault flow simulation is also performed. The fault flow simulation is used to evaluate the protection criteria and to determine the DER level that can be interconnected to each node without hindering the protection devices' ability to detect fault conditions. This approach requires multiple load flow and short-circuit duty iterations on each node across the feeder being analyzed. Due to the large number of iterations required, iterative power flow analysis can result in long processing times, especially when expanded to large numbers of distribution feeders or when the ICA values are required for a large number of loading conditions. However, the use of an Iterative Method parallels the IOUs' interconnection studies performed as part of an interconnection detailed study process and provides greater confidence in representation of integration capacity.

### 4.1.3. Layered Abstraction Approach

Important to this process and regardless of calculation techniques is the concept of layered abstraction. By defining layers that represent the electric system hierarchy, where explicit criteria calculations can be made within each layer independent of another layer's calculation. This helps organize the results in a way that can inform specific limitations to a single point of interconnection or broader limitation to a feeder or substation. Performing the analysis using abstract and layered thinking is helpful for two reasons:

1. Enabling further improvement of ICA's scope and granularity.
2. Streamlined processing for vast datasets.

Figure 9 visualizes the integrated process of evaluation across the criteria at each layer. This integrated technique is important to get results for both node specific limitations, device limitation, circuit breaker limitations and substation level limitations. For instance, locational results can be limited by a higher level constraint such as the thermal limitation of a substation transformer, therefore limiting the total amount of possible DER that can be interconnected on the downstream feeders, nodes and line sections.



[14]

FIGURE 9: LAYERED ABSTRACTION COMPONENT

## 4.2. Establish Distribution System Level of Granularity

SCE performed its ICA calculation using both the Streamlined and Iterative Methods. These two methods computed the ICA values down to all three-phase primary nodes and line sections for all distribution feeders within the two selected DPAs. Equipment is attached to the nodes at the beginning or end of each line section.


FIGURE 10: NODE CONNECTIVY DIAGRAM

## 4.3. Extract Power System Data

Two sets of system data are essential for accurate ICA calculations. First, load and generation profiles, which define various loading scenarios that the grid may experience, were developed using SCE's load forecasting tool. Second, power flow network models were created that represent the system electrical connectivity and device settings of the distribution feeders and system.

---

[14] "T" refers to Thermal Limit, "PQ" refers to Power Quality/steady-state-limit, "P" refers to the protection limit, and "SR" refers to safety and reliability limit

In combination with load and generation profiles, the network models can be used to simulate the system behaviors under different loading and DER levels via power flow analyses. The feeder and substation network models are developed in the power flow analysis tool, CYMDIST.

### 4.3.1. Load and Generation Profile Development

SCE developed hourly load forecasts for each distribution feeder based on one year of hourly loads (8,760) to derive normal and scenario based load shapes. New software tools were used to rectify load abnormalities, impute outliers, assess load transfers, and remove other PV, DR, and EE influences.

Once the 8760 hourly load profile is determined for each circuit, the 576 hourly load profile is obtained by selecting the 24-hour period for the typical minimum and maximum load day for each of 12 months within the 8760 hourly load profile (12 months× 24 hours× 2 profiles = 576 load data points). Figure 12 shows an example of the 2-288 hour (576 hour) point profiles with one 288 hourly profile representing the typical maximum profile and the second profile representing the typical 288-hour minimum profile while Figure 11 shows a typical 8760 hour profile These load profiles were then used to initialize the loading conditions for each of the distribution feeder network models

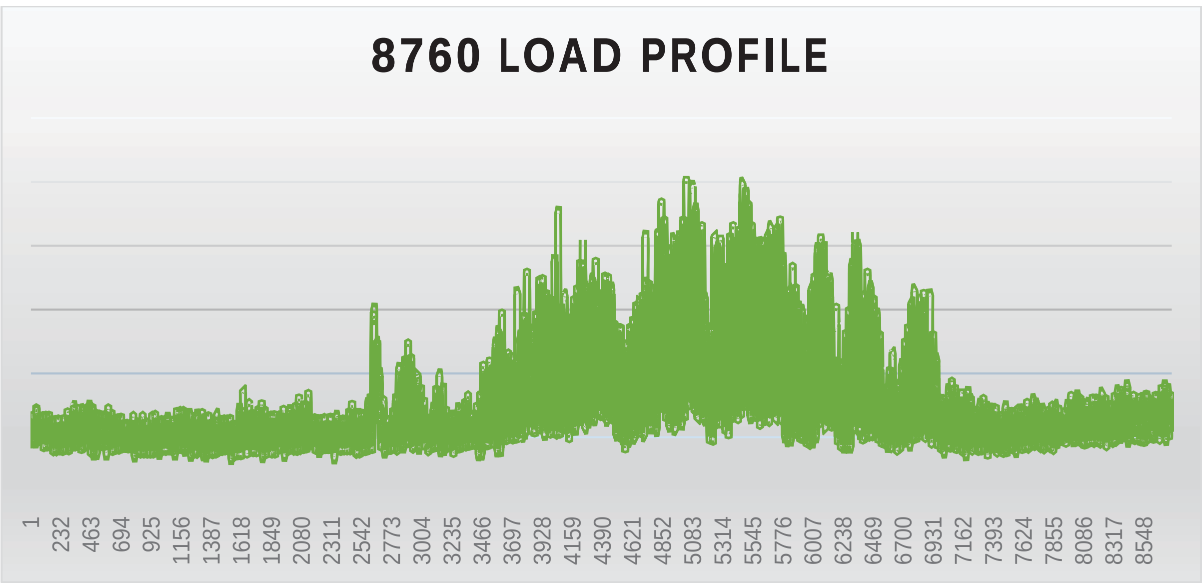



FIGURE 11: SAMPLE 8760 HOURLY PROFILE

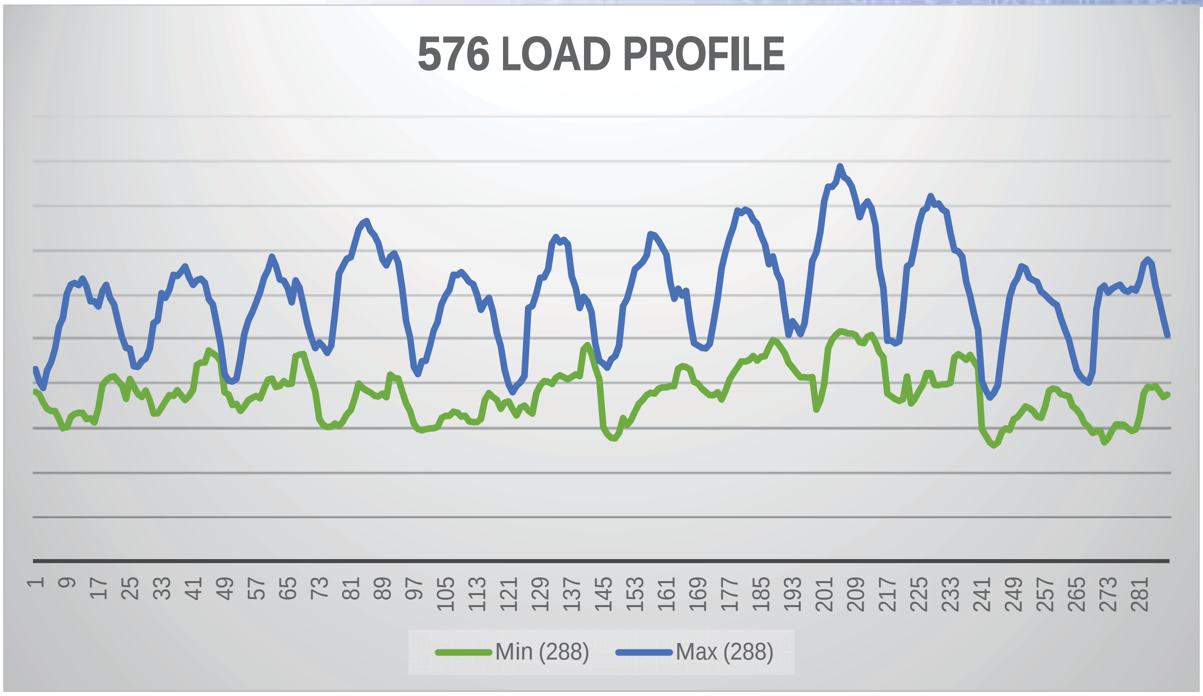



FIGURE 12: 576-POINT PROFILE SAMPLE

Generally, customers from different classes have different load shapes and may also have different energy usage patterns. To take these load shapes and patterns into account, hourly customer load data from smart meters was aggregated to service transformers to form more localized load shapes. These localized shapes in combination with the developed 576 base load hourly profile as outlined in 4.3.1 were, in most cases, utilized to allocate the feeder level forecasted load down to the service transformer level or individual customer level.

### 4.3.2. Power Flow Model Development

SCE developed distribution feeder and substation models in CYMDIST and validated the parameters to make sure these system network models reflected the most accurate field conditions so that the calculated DER capacity limits reflect the most accurate limitation.

SCE first used Python scripts to read the latest asset information from a comprehensive Geographic Information System (cGIS) database and built the initial feeder models in CYMDIST. These circuit models include conductors, line devices, loads and generation components. The existing DERs on these feeders, obtained from the generation database, were included in the feeder models to reflect current levels of penetration.

Substation and feeder modeling were based on normal system operating conditions as shown in Figure 13 and Figure 14.

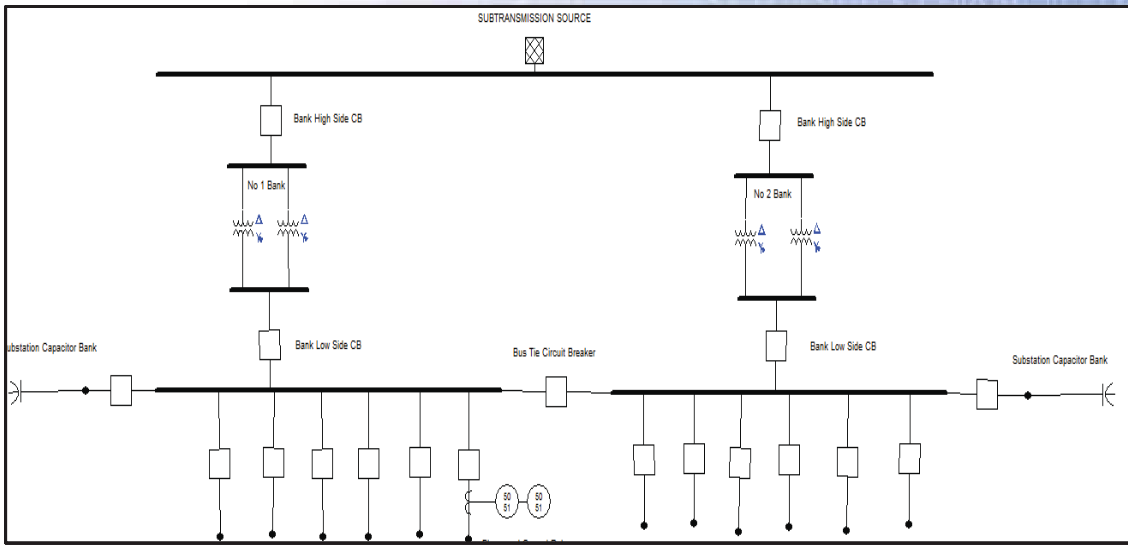



FIGURE 13: SUBSTATION COMMON BUS MODEL

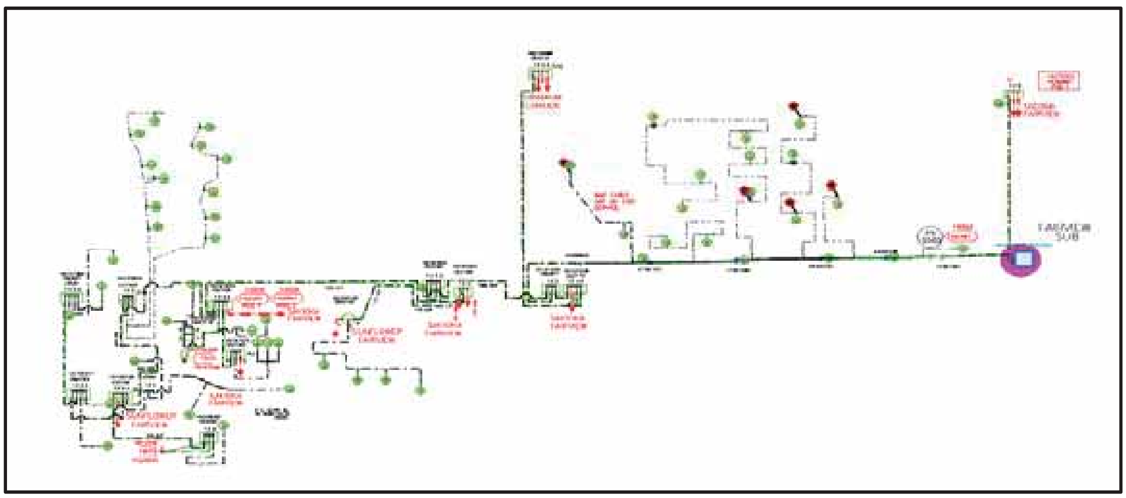


FIGURE 14: TYPICAL DISTRIBUTION FEEDER SIMULATION MODEL

To ensure that feeder and substation network models represent the most accurate system configuration, it is essential to perform network model validations. To accomplish this, a multi-pass network sweep was performed to clean up the potential issues in the initial models such as broken connectivity and missing electric parameters. The model validation utilized various data sources (such as circuit maps, facility inventory maps, SAP and DMS) to obtain information and replace the missing parameters with the actual information. The major categories of validation included the type/length/phase of cables and conductors, the size and rated voltage for capacitor banks, and the rating of switches and grid devices. While automated network validation sweeps create network models which are generally adequate for high level analysis, these network models require that engineers perform the final preparation of the network models including performing proper phasing, verifying device connectivity and settings, and testing the network models under various load levels to ensure convergence which indicate that a power flow was successfully calculated. The combination of automated network model creation, multi-step data clean up sweeps, and engineering review gives confidence that the network model created is sufficiently accurate to represent real system conditions.

## 4.4. Evaluate Power System Criteria to Determine DER Capacity

Power system criteria are the principles that determine the capability of the system to integrate DER. As required by the ACRs, four major categories of power system criteria are considered in Demo A to determine the DER integration capacity for the nodes and line sections on each distribution feeder. These four criteria are thermal rating, power quality and voltage, protection system limits and safety and reliability standard of existing equipment. Each power system criterion is evaluated independently and the most limiting value is used to establish the integration capacity limit for the corresponding node/section.

### 4.4.1. Calculation Techniques

The ICA calculation techniques being demonstrated in Demo A provide approaches that can be implemented towards evaluating distribution system limits to integrate DERs across SCE's service territory. The specific technique driving the methodology has two main goals; (1) improve accuracy and (2) improve efficiency. These two objectives, in general, can lead to diverging paths when developing a calculation methodology. With these goals in mind, the Demo A project aims to determine the best path forward to strike a proper balance between the two goals. There are two calculation techniques being explored within Demo A. These are:

*Streamlined Calculation*

- Promotes efficiency through reduced simulation and principles of abstraction.
- Simplified or abstracted evaluation based on algorithms with input from hourly baseline power flows.
  - Requires less processing resources and enables more batch output insights (e.g., for DER planning where multiple scenarios are needed).
  - May prove less accurate since the resource is not directly modeled.

*Iterative Simulation*

- Promotes detail and accuracy through direct modeling and observing simulated conditions.
- Increased confidence in accuracy due to direct modeling of resource.
- More accurate representation of DER impact to electrical conditions of circuit.
- Requires powerful computing through simulation of iterative placement/upsizing of DER in model to simulate very precise conditions with many power flows.
- Best for simulating complex systems.
- Method of analysis parallels the detailed analysis performed within the interconnection process.

Working gorups and demo projects are paths to test, compare, and improve methodologies. Multiple techniques enhance innovation to tackle problems with a wide range of complexity, especially at this early stage. One may find that an iterative solution can serve more complex problems, while a streamlined calculation can serve simpler problems. Moreover, when multiple methods return similar results, one can have increased confidence (triangulation, or convergent validity). A blended approach may be more efficient, less risky and more effective in enabling innovative, valid and efficient outcomes. It can also help in meeting the objectives of the use cases identified by the ICAWG, including enabling the ability to expedite the interconnection process.

### *Streamlined Method*

The Streamlined Method applies a set of streamlined algorithms for each power system limitation category/sub-category to evaluate the DER capacity limit at each node of the distribution feeders. This helps to enable system wide scenario analysis with much less processing requirements. For instance, batch power flows are performed to obtain electrical initial conditions and data such as but not limited to ampacity flows, voltages, fault duties, and impedances. The final results are determined by inputting this data into the streamlined algorithms to determine the integration capacity for each limitation.

Figure 15 illustrates how each power system limitation criterion is evaluated at each node though power flow or short circuit duty (SCD) analyses and how the final ICA values are established at each node based on the most limiting individual ICA values. For the scenario that is to evaluate the maximum integration of DER irrespective of direction of power flow, the safety/reliability criterion (i.e., operational flexibility) will be excluded so that the maximum DER can be studied irrespective of power flow direction

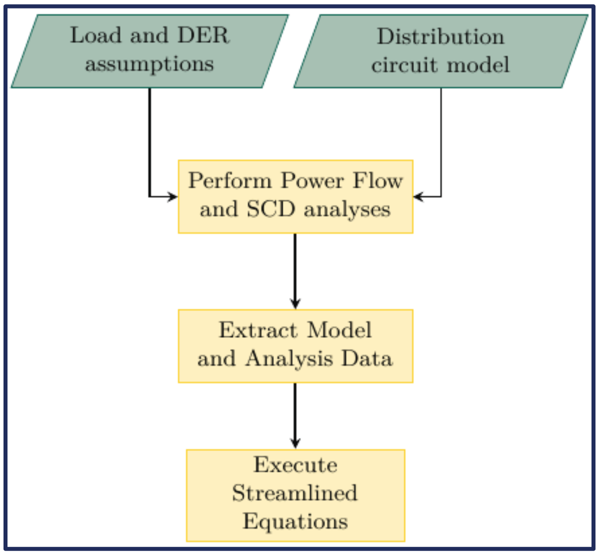



FIGURE 15: CRITERION EVALUATION PROCESS

### *Iterative Method*

The Iterative Method is the direct modeling of new resources and performing iterative simulations for determining integration capacity at each node. Each analysis uses power flow calculation engines to compute the phase currents and voltages at every node on the network given the load and generation levels in the model. The Iterative Method is consistent with engineering simulations performed on new interconnections during detailed studies. This method is expected to provide results that are expected to be more indicative of field conditions.

Figure 16 illustrates how each power system limitation criterion is evaluated at each node though power flow or short circuit analyses and how the final ICA values are established at each node based on the most limiting individual ICA values. For the scenario that is to evaluate the maximum integration of DER irrespective of direction of power flow, the safety/reliability criterion (i.e., operational flexibility) will be excluded so that the maximum DER can be studied irrespective of power flow direction

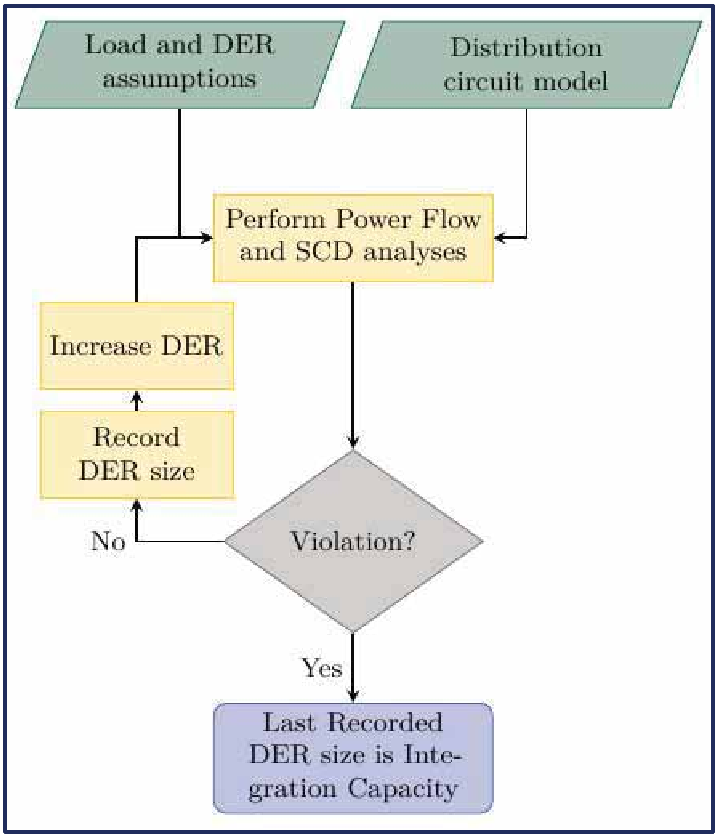



FIGURE 16: SIMPLIFIED HIGH-LEVEL VIEW OF ITERATIVE METHODOLOGY

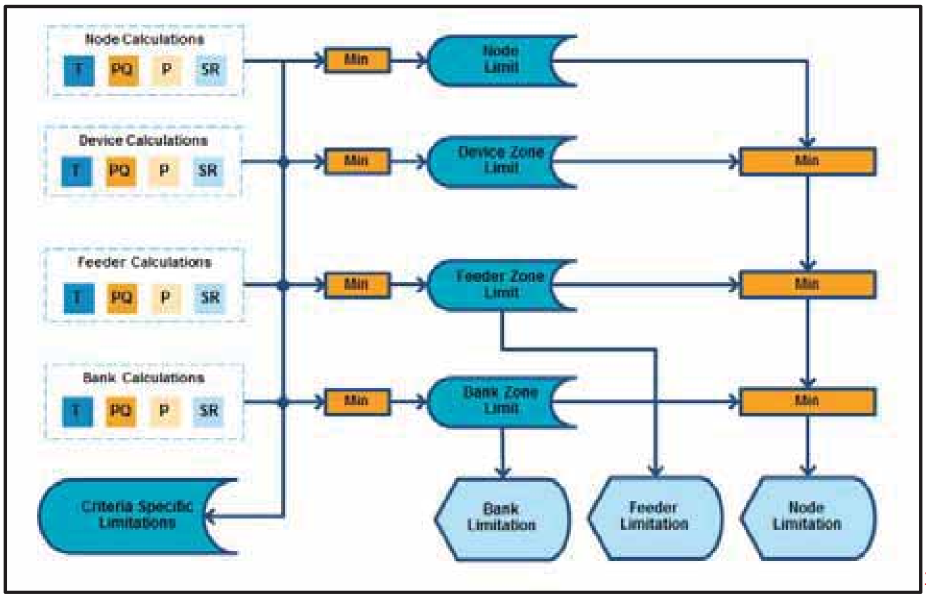
This method allows for the best precision but requires increased computational resources. Due to the precision of this approach, it is best suited for complex feeders where the Streamlined Method has difficulty modeling the dynamic voltage device operations on longer circuits or to establish a limited set of calculations that are needed for purposes of increasing the efficiency of the interconnection process. System wide analysis can be made more efficient by using various methods of computational efficiency that are discussed in Section 9.1.

SCE limited the maximum ICA to 20 MW for its Iterative Method to balance the efficiency of ICA value calculation without negatively affecting actionable ICA values. This limitation was implemented for the following reasons:

1. CYME, the power flow tool utilized by SCE, required the input of an upper bound to commence the simulation. The higher the starting value, the more iterations it takes to arrive at the correct value and thus the longer the time required to arrive at the ICA value. Having values greater then 20MW would significantly increase computation time unnecessarily.
2. Installing up to 20MW on a 12KV distribution feeder (Demo A voltage class levels) is not practicable thus determining ICA values higher than 20 MW is not practicable because SCE's typical distribution feeders are rated to serve up to 12MW.

### *Final Processing of Criteria Calculations*

The analysis looks at various layers of the system and ensures that the higher-level layers impact or limit the lower layers when applicable. For example, the reduction of reach at a feeder location would limit the ICA on all the nodes at lower layer of that feeder location (downstream nodes). Figure 17 depicts the general process that is used to obtain the final set of results.



[15]

FIGURE 17: ABSTRACTION TECHNIQUE FOR INTEGRATING RESULTS ACROSS SYSTEM LAYERS

## 4.4.2. Thermal Criteria

Thermal criteria determine whether the addition of DER to each node on the distribution feeder causes the power flow to exceed any equipment thermal ratings. These limits are the rated capacity of the conductor, transformer, cable, and line devices established by SCE's engineering standards or equipment manufacturers. Exceeding these limits would cause equipment to potentially be damaged or fail, therefore mitigation measures must be performed to alleviate and prevent thermal overloads.

An hour-by-hour calculation is performed to determine the level of DER which can be interconnected without exceeding equipment thermal limits. For this criteria, the Integration

[15] T- Thermal, PQ- Steady State Voltage/Power Quality, P-Protection, SR- Steady State Voltage

Capacity value is the highest value of DER which can be connected at a node which does not exceed the thermal rating of any piece of upstream[16] equipment on the distribution circuit or substation. An example is depicted in Figure 18.

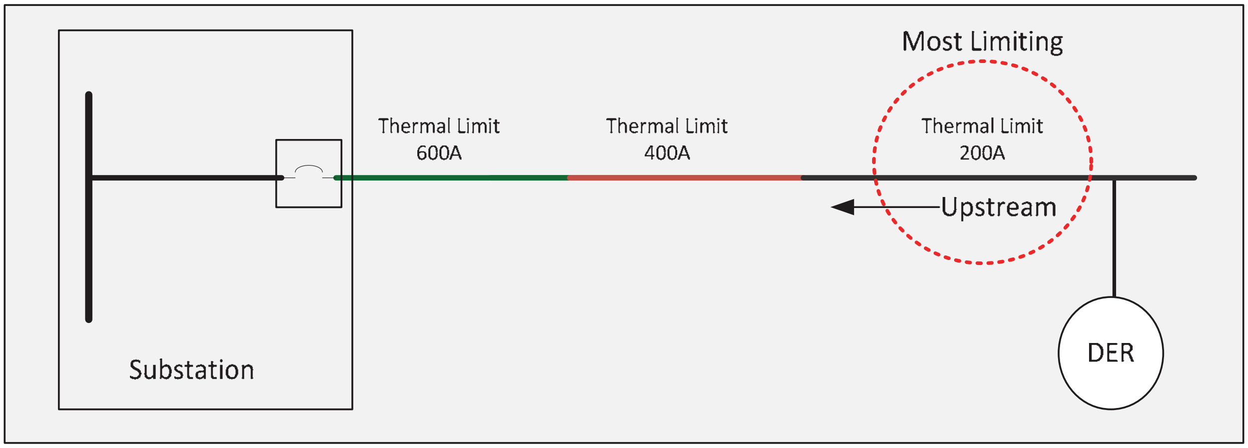



FIGURE 18: MOST LIMITING COMPONENT SAMPLE

The table below shows the equations and flags used to evaluate thermal limitations in the Streamlined Method and the Iterative Method, respectively.

| | |
|---|---|
| <u>Streamlined</u> | $\text{kW Load Limit [t]} = \left(\text{Thermal Capability } - \left(\text{Load[t]} - \text{Generation [t]}\right)\right)$ <br> $\text{kW Generation Limit [t]}$ <br> $= \left(\text{Thermal Capability } + \left(\text{Load[t]} - \text{Generation [t]}\right)\right)$ |
| <u>Iterative</u> | Power flow determines maximum DER without exceeding device thermal rating |

In the equations, "kW Load Limit [t]" refers to the integration capacity value for energy consuming DERs at hour t; "kW Generation Limit [t]" refers to the integration capacity value for energy producing DERs at hour t; "Thermal Capability" refers to the 100% of the most limiting equipment's loading limit from the substation to the node being analyzed; "Load[t]" refers to gross load at hour t; "Generation[t]" refers to gross generation at hour t for the node being analyzed; "Load[t]-Generation[t] represents the Net Power flow at hour[t] at the most limiting equipment from the substation to the node being analyzed.

[16] The terms "**upstream**" refers the electrical equipment (cable, wires, transformers, load, DER, etc.) bounded by the location of reference (node being analyzed) to the substation. The terms "**downstream**" refers the electrical equipment bounded by the location of reference to the farthest end of the distribution line

### 4.4.3. Power Quality / Voltage Criteria

Power Quality / Voltage Criteria is used to determine whether the addition of DER to each node on the distribution feeder causes the distribution primary feeder to operate outside of allowable power quality or voltage limits

There are two voltage related limits which must be evaluated. The steady state voltage limits and voltage fluctuation limits established by IOUs' Rule 2[17] and Engineering Standards, which are drawn from American National Standard (ANSI) C84.1 - 2011 Range A.

### 4.4.4. Steady State Voltage Criteria

In agreement with other the IOUs, the Steady State Voltage (SSV) criteria flag was added to the Baseline Method as this flag is an essential element in power systems evaluations.

The table below shows the equation and flag used to evaluate steady state voltage limitations in the Streamlined Method and the Iterative Method, respectively.

| | |
|---|---|
| <u>Streamlined</u> | $\text{kW Limit [t]} = \frac{\left(\text{Voltage Headroom [t] (per unit)} * {V_{LL}}^2\right)}{\left(R * PF_{DER} + X * \sin(\cos^{-1}(PF_{DER}))\right)} * PF_{DER}$ <br> $\text{Voltage Headroom [t]} = \frac{\lvert\text{Rule 2 Limit} - \text{Node Voltage[t]}\rvert}{\text{Base Voltage}}$ |
| <u>Iterative</u> | Power flow tool flags a steady state over-voltage condition when simulated voltage at any node exceeds 126V and flags an under-voltage condition when simulated voltage drops below 114V at any node. |

Steady state voltage changes can be generally estimated using Ohm's Law. This limit is determined by comparing the simulated voltage at the node to the Rule 2 steady state voltage limits (i.e., the voltage shall remain in the range between 0.95pu and 1.05pu or 114 to 126 on a 120V base).

In the equation, "$V_{LL}$" refers to the actual circuit voltage at hour "t"; "R" and "X" refer to the line impedance from the substation to the node under study, "$PF_{DER}$" refers to the power factor of DERs, which is assumed at 1p.u. in the study. Section 8 evaluates smart inverters and DER operating at other power factors.

### 4.4.5. Voltage Fluctuation Criteria

Voltage fluctuation is evaluated to ensure that varying loads (e.g. motors starting) and variable resources (e.g. cloud cover resulting in PV output reduction) on the grid do not cause significant voltage fluctuations which may affect power quality to nearby customers and potentially cause harm to electrical components connected to the grid. The voltage fluctuation limit used in Demo A is 3%[18], which is prescribed by engineering standard practices. The table

[17] https://www.sce.com/NR/sc3/tm2/pdf/Rule2.pdf
[18] The 3% limit can be found in IEEE Std 1453-2015 "IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems" in Table 3 for medium voltage systems.

below shows the equation used to evaluate voltage fluctuation limitations in the Streamlined Method.

| | |
|---|---|
| <u>Streamlined</u> | $\text{kW Limit} = \frac{\left(\text{Deviation Threshold (per unit)} * V_{\text{LLnom}}{}^{2}\right)}{(R * PF_{DER} + X * \sin(\cos^{-1}(PF_{DER})))} * PF_{DER}$ |
| <u>Iterative</u> | a. Record voltage at node<br>b. Simulate generation at node<br>c. Vary generation levels until deviation threshold is surpassed<br>d. Generation level closest to but under the allowed deviation value is the limit<br>e. Compare node voltages with DER on and off<br>f. Highest value recorded before deviation threshold is surpassed |

The equation used for voltage fluctuations is fundamentally derived from Ohm's law. In the equation, "Deviation Threshold" refers to the voltage fluctuation limit, which is 3% of the nominal circuit voltage in the study; "$V_{LLnom}$" refers to the nominal circuit voltage; "R" and "X" refer to the line impedance from the substation to the node under study, and "$PF_{DER}$" refers to the power factor of DERs, which is assumed at 1.0 in the study.

The Iterative Method will run a power flow with the DER on and off and compare the node voltages before and after. All voltage devices on the feeder must be locked in order to understand the true voltage variation before any voltage regulating devices correct for such changes. When the voltage deviation for a node surpasses the set threshold, then the DER size is recorded for that node.

### 4.4.6. Protection Criteria

Protection criteria examines whether the addition of DERs to the distribution feeder reduces the ability of existing protection schemes to monitor the grid and promptly respond to abnormal system conditions to maintain safety. This condition is referred to as reduction of reach.

If a fault occurs electrically downstream of a distribution protection device such as a relay, the device is designed and programmed to detect the abnormal condition and signal an interrupting device, such as a circuit breaker, to interrupt the high magnitude fault current to isolate the affected portions of the circuit from the rest of the system. Typically, these devices are programed with defined Minimum Trip current settings so that the device does not open during normal peak loading conditions but can still detect the lowest fault current possible within its defined protection zone and trip quickly enough to safely isolate the affected system.

If generating DERs are placed electrically downstream of a protection device, these DERs become sources of power that can contribute short circuit current to a fault downstream from the protection device. Under this condition, the fault current contribution from the utility distribution grid (e.g., the substation) will be reduced which will affect the ability of the protection device to detect the abnormal condition and may not signal the fault interrupting device to open in a timely manner. When a DER causes significant reduction of reach, the distribution protection device may not operate at all, resulting in potential damage to the distribution system or customer equipment and increased risk of injury to the public. DER planning must account for the impacts DERs will have to protection schemes to ensure that they operate properly as required to keep employees, public, and assets safe from potential electrical disturbances on the distribution system.

The table below shows the equation and flag used to evaluate the reduction of reach limitations in the Streamlined Method and the Iterative Method, respectively.

| | |
|---|---|
| Streamlined | $\text{kW Limit} = \dfrac{\text{Reduction Threshold Factor} * I_{\text{Fault Duty}} * kV_{LL} * \sqrt{3}}{\left(\dfrac{\text{Fault Current}_{\text{DER}}}{\text{Rated Current}_{\text{DER}}}\right)} * PF_{\text{DER}}$ |
| Iterative | Power flow tool flags when the DER connected at a node causes the relay to detect less than 2.3*relay's phase minimum [19]trip value |

The streamlined equation follows the screening concept that issues may arise when DER fault current reaches a certain percentage of maximum fault duty at the node being analyzed.

In this equation, "Reduction Threshold Factor" refers to the threshold which DER is allow to contribute as a percent of the total short circuit current at the node being studied. In Demo A, SCE used 10% as the reduction threshold as specified in Rule 21; "$I_{\text{Fault Duty}}$" refers to the maximum fault current at the node being studied; "$kV_{LL}$" refers to the circuit nominal voltage; "$\text{Fault Current}_{\text{DER}}/\text{Rated Current}_{\text{DER}}$" refers to per unit DER fault current contribution, which is assumed to be 1.2 for inverter-based DERs[20].

The Iterative Method performs a fault flow analysis to evaluate the changes in fault flow at the protection devices due to DER being connected downstream from the protection device. The fault flow tool takes into account the impedances between the fault location and the protection device as well as the DER nameplate capacity to determine the maximum level of DER which can be connected at a node without causing the fault flow at the relay to go below minimum trip value by typical protection engineering practices. The analysis determines the largest value of DER which can be connected without violating this criterion. Figure 19 depicts the reduction of reach concept being utilized for Demo A.

[19] SCE's typical practice of applying minimum trip settings
[20] National Renewable Energy Laboratory, "Understanding Fault Characteristics of Inverter-Based Distributed Energy Resources", p.p.33

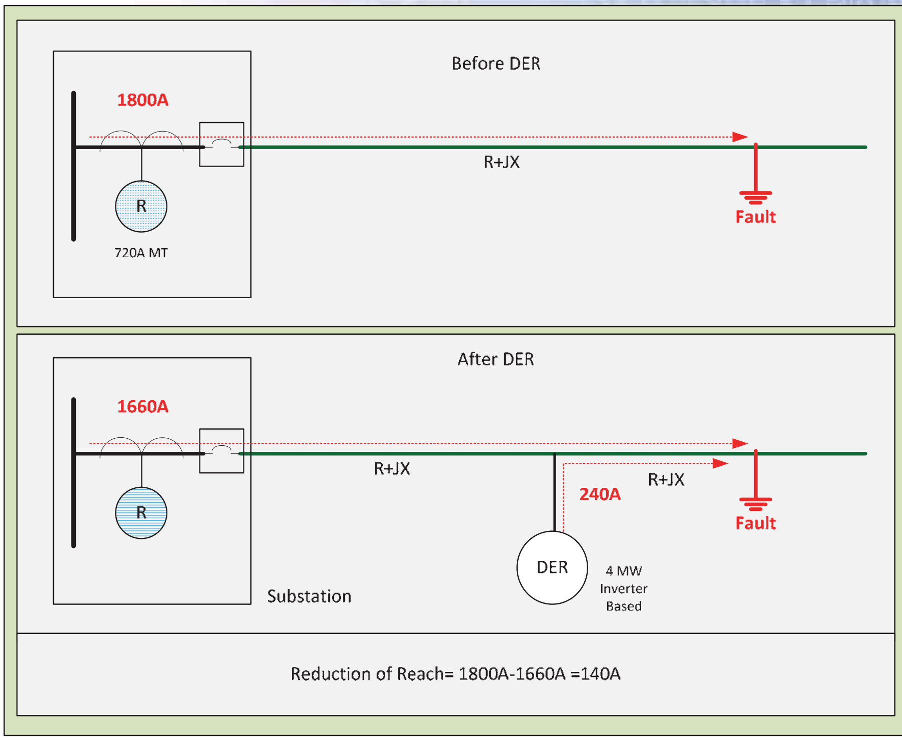



FIGURE 19: REDUCTION OF REACH CONCEPT

### 4.4.7. Safety / Reliability Criteria

Safety and Reliability must also be analyzed as part of the Integration Capacity Analysis. High penetration of DER has the potential to cause excess reverse power flow, thermal overloads and overvoltage that can result in reliability concerns. Each of the tested criterion, thermal, protection, voltage fluctuation and operational flexibility all are essential for maintaining safety and reliability.

### 4.4.8. Operational Flexibility Limits

Safety/Reliability Criteria is also assessed based on operational flexibility, which determines the ability to reliably serve portions of circuits in abnormal configurations. High DER penetration can potentially cause excess reverse flow and load masking which may result in poor reliability conditions during abnormal system configurations, circuit transfers and emergency restoration. When certain line sections are electrically isolated from the grid for repair or maintenance, other line sections are transferred to other distribution feeders to minimize the amount of customers affected by an outage. To maintain a high level of reliability, the distribution system is designed so that it can be rearranged in a manner that unexpected power flows may create safety and reliability concerns.

To maximize reliability during these abnormal system configurations, the Operational Flexibility Criteria limits the amount of back feed through SCADA switching points so that when a line section is switched to a new configuration, the amount of generation on that section will only serve the local load and does not generate power through the tie point towards the alternative source. In effect, the criteria will match the generation to the load between a circuit tie switch and the adjacent SCADA controlled switching device on the feeder.

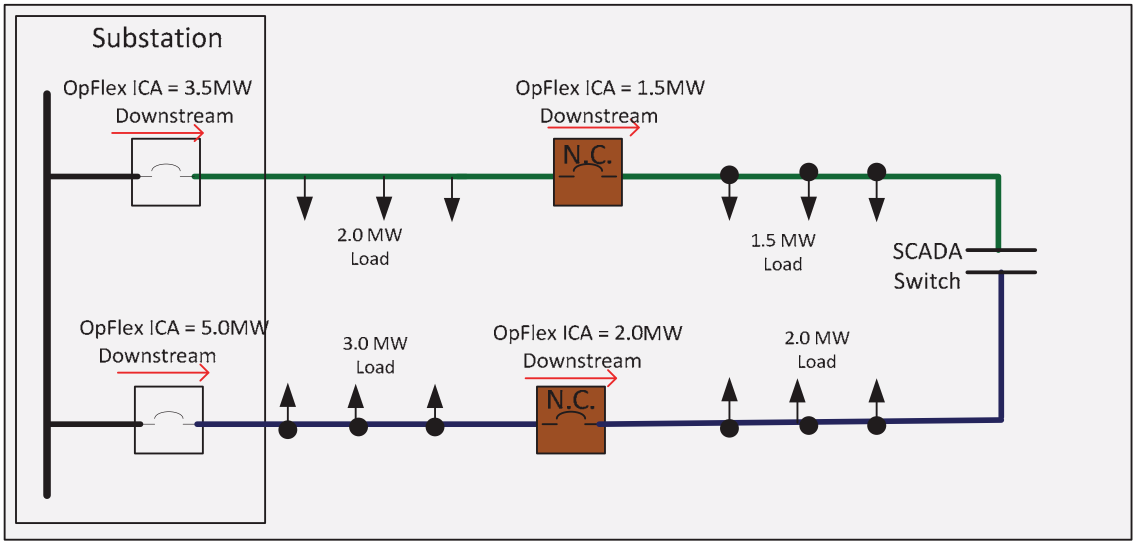



FIGURE 20: OPERATIONAL FLEXIBILITY LIMIT

A second reverse flow criteria is associated with voltage regulators. Voltage regulators have been designed, installed and programmed to properly control voltage when power flow is in one direction (From the substation to the load). When the power flow changes direction at the voltage regulator (reverse power flow), the settings and capabilities of the VR must be reviewed prior to allowing levels of DER which would create a reverse power flow condition at the voltage regulator, which would result in improper operation of the VR. Figure 21 shows the Operational Flexibility limit for nodes beyond a voltage regulator.

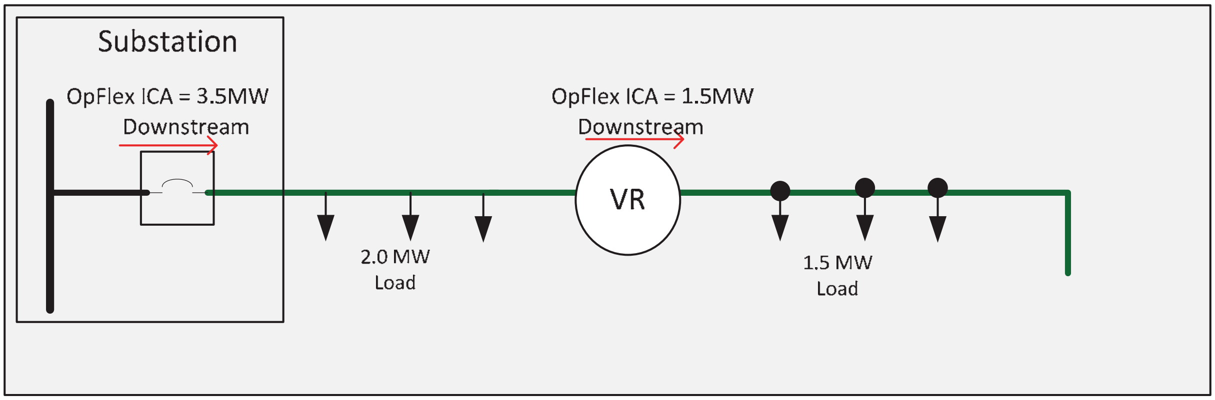



FIGURE 21: VOLTAGE REGULATOR LIMITATION SAMPLE

The table below shows the equation and flag used to evaluate the operational flexibility criteria in the Streamlined Method and the Iterative Method, respectively.

| | |
|---|---|
| Streamlined | $\text{kW Limit }[t] = \left(\text{Load}[t] - \text{Generation }[t]\right) \mid \text{ where limit} > 0$ |
| Iterative | Power flow tool calculates the downstream load at the SCADA or VR devices and equates that load value to be the DER value which can be installed without causing reverse power flow. . |

Because both the Streamlined and Iterative Methods run an initial power flow study, this analysis is the same for both methods. The first step in the ICA process for both methods is to determine the network initial conditions by performing a power flow based on that hour's loading and voltage conditions. This initial power flow simulation sets the initial loading values along the network and determines the load beyond each of the SCADA switches or voltage regulators. Once those loading values are determined, then no additional iterative power flow analysis is required and the ICA value for this criteria is equal to the simulated load downstream from the SCADA switch or voltage regulator at that hour of analysis.

The IOUs recognize that this is more of a heuristic approach. While heuristic approaches were not encouraged, the IOUs have established that non-heuristic approaches to analyzing this issue are quite process intensive and will significantly hinder the ability to achieve efficient results. In essence, this will not necessarily limit the amount of generation that can be placed on each circuit or substation, but will disperse the allowable generation across all line sections connected to the circuit or substation. This is an important aspect of reliability that needs to be addressed for higher penetration of DER.

### 4.4.9. Substation Limitations

*Circuit breakers*

Substation circuit breakers have two limitations which must be explored during ICA evaluations. The first consideration is the continuous thermal rating of breaker. The second limitation is the fault interrupting capability of the circuit breaker, which is the capability of the breaker to safely interrupt high levels of fault current. In most cases, this value would not be a limitation as the substation breaker interrupting capability is typically substantially higher than the ICA identified at any feeder node. However, as the level of connected generation increases at both the bulk power and distribution systems as shown on Figure 22, the level of fault current in the system will also increase. Thus in cases when the level of fault current is near the breaker interrupting ratings, substation breakers would limit the ICA values on the feeder nodes.

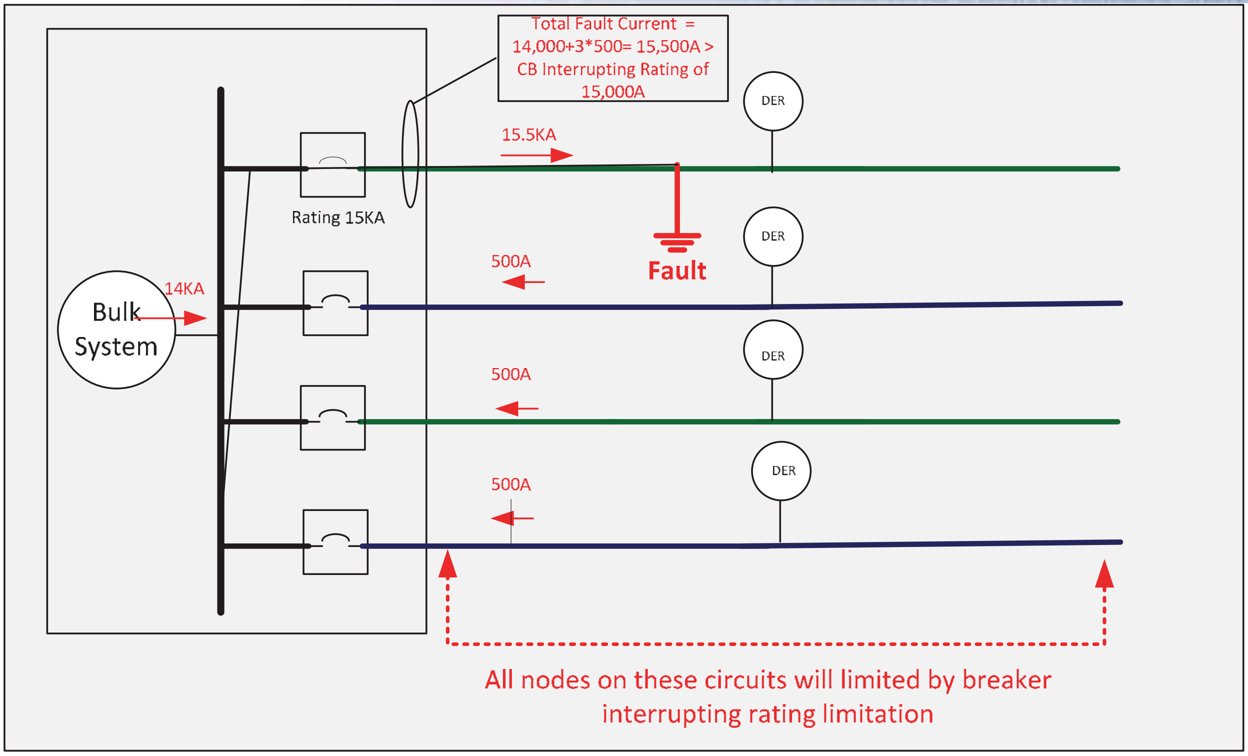



FIGURE 22: SAMPLE OF BREAKER INTERRUPTING LIMITATIONS

### 4.4.10. Substation transformers

Substation transformers would only become a limitation when reverse power flow is allowed from the distribution system towards the transmission system and the level of export exceeds its thermal capacity ratings. Commonly, the substation transformer rating would be significantly higher than any one node on the distribution feeders, thus it is not expected that a substation transformer limitation would cause a reduction in node ICA. However, as penetration of DER increases across the distribution feeders, the capacity margin at the substation will decrease to the point where the substation available capacity will influence the ICA values at other levels.

# 5. Results

In this section of the report, SCE describes how each of the ACR scenarios and requirements are met, provides representative illustration of the results, and explains the results files that can be downloaded from the following SCE site: http://on.sce.com/drpdemos

It is important to outline that these results do not take into account established distribution planning limitations and are strictly based on the assumptions outlined in the section 4 (methodology). To this end, the feasibility of installing large levels of DER (such 20 MW) in the distribution system will likely pose significant challenges.

## 5.1. General Description (including different scenarios)

### 5.1.1. Two Power Flow Scenarios:

- The DER capacity does not cause power to flow beyond the substation busbar

  These values are represented on the downloadable tables as "STREAMLINED_ICA_GEN_NOREVERSE (kW)" for the Streamlined Method and the "ITERATIVE_ICA_GEN_REVERSE (kW)" for the Iterative Method.

| STREAMLINED_ICA_GEN_NOREVERSE (kW) | ITERATIVE_ICA_GEN_NOREVERSE (kW) |
|---|---|

- The DERs technical maximum capacity is considered irrespective of power flow toward the transmission system

  This value is represented on the downloadable tables as "STREAMLINED_ICA_GEN_REVERSE (kW)" for the Streamlined Method and the "ITERATIVE_ICA_GEN_NOREVERSE (kW)" for the Iterative Method.

| STREAMLINED_ICA_GEN_REVERSE (kW) | ITERATIVE_ICA_GEN_REVERSE (kW) |
|---|---|

### 5.1.2. Three Load Forecasting and DER Growth Scenarios:

- 2-year growth scenario utilities use for distribution planning

  The values are represented in the downloadable results file the "DSP" in the "SCENARIO" filter.

| SCENARIO |
|---|
| DSP |

- Growth scenario I as proposed in the DRP Applications

  The values are represented in the downloadable results file the "DER1" in the "SCENARIO" filter.

| SCENARIO |
|---|
| DER1 |

- Growth scenario III as proposed in the DRP Applications

  The values are represented in the downloadable results file the “DER3” in the “SCENARIO” filter.

| SCENARIO |
|---|
| DER3 |

### 5.1.3. Three Typical DER Operational Profiles[21]:

- Inverter-based uniform generation

  These profiles can be generated from the downloadable files by applying the desired filters. As an example, to obtain the minimum 288-hour profile for ***Uniform Generation***, with the Iterative Method using the “2-years growth” scenario at a particular node, the following filters are to be selected:
  - Selection_ID: **Node of Interest**
  - Load type = **Min**
  - Month = **Select all 12 months**
  - Hours = **Select all 24 hours**
  - Scenario: **DSP**

  <u>Data & Profile</u>
  - Extract data for: **“ITERATIVE_ICA_GEN_NOREVERSE”**
  - Plot profile

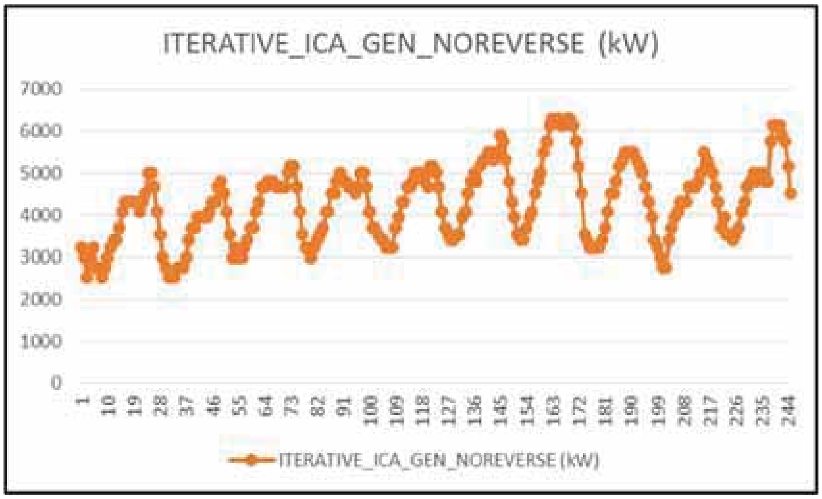



FIGURE 23 SAMPLE ITERATIVE ICA REULSTS (GEN) WITH NO REVERSE POWER FLOW

| SECTION_ID | Load_Type | MONTH | HOUR | ITERATIVE_ICA_GEN_REVERSE (kW) | ITERATIVE_ICA_GEN_NOREVERSE (kW) | SCENARIO |
|---|---|---|---|---|---|---|

[21] The ACRs direct Utilities to evaluate the integration capacity for different DERs using a set of ‘typical’ DER operational profiles and quantify the integration capacity for portfolios of resource types using representative portfolios. Due to the uncertainty of the DER operational profiles from manufacturers, geographic locations, and operating practice, it was agreed, based on the discussions in the ICAWG meetings, that Utilities would present the ICA results for inverter-based uniform generation, uniform load and PV generation between 10AM and 4PM under minimum loading conditions.

### 5.1.4. Fixed axis PV

These profiles can be generated from the downloadable files by utilizing the "ICA_PV (KW)" filter. As an example, to obtain the minimum 288-hour ***PV shape profile***, with the Iterative Method using the "2-years growth" scenario at a particular node, the following filters are to be selected:

- Selection_ID: **Node of Interest**
- Load type = **Min**
- Month = **Select all 12 months**
- Hours = **Select all 24 hours**
- Scenario: **DSP**

<u>Data & Profile</u>

- Extract data for: **"ICA_PV(KW)"**
- Plot profile

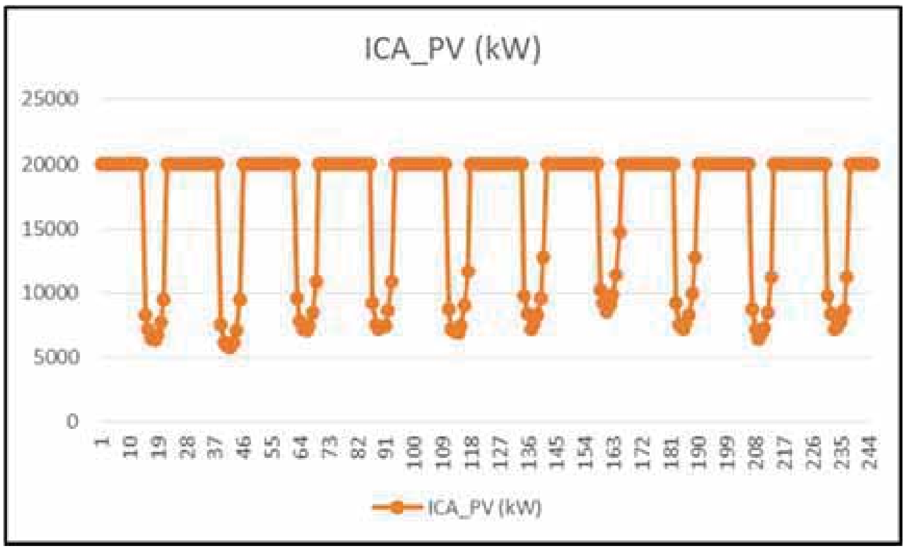



FIGURE 24 SAMPLE ITERATIVE ICA REULSTS (TYPICAL PV) WITH NO REVERSE POWER FLOW

| SECTION_ID | Load_Type | MONTH | HOUR | ICA_PV (kW) | SCENARIO |
|---|---|---|---|---|---|

### 5.1.5. Uniform load

These profiles can be generated from the downloadable files by applying the load filters. As an example, to obtain the minimum 288-hour profile for ***Uniform load***, with the Iterative Method using the "2-years growth" scenario at a particular node, the following filters are to be selected:

- Selection_ID: **Node of Interest**
- Load type = **Min**
- Month = **Select all 12 months**
- Hours = **Select all 24 hours**
- Scenario: **DSP**

Data & Profile

- Extract data for: **“ITERATIVE_ICA_LOAD (KW)”**
- Plot profile

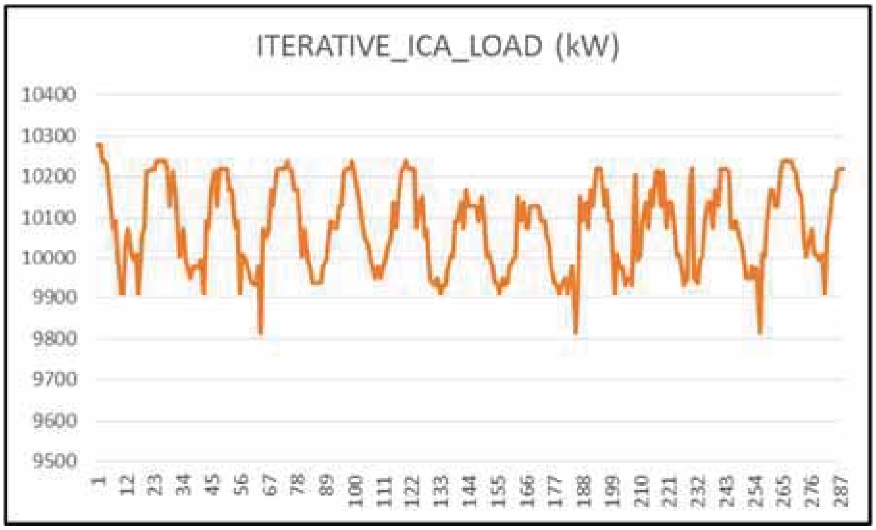



FIGURE 25 SAMPLE ITERATIVE ICA REULSTS (LOAD)

| SECTION_ID | Load_Type | MONTH | HOUR | ITERATIVE_ICA_LOAD (kW) | ICA_PV (kW) | SCENARIO |
|---|---|---|---|---|---|---|

Through this analysis, SCE generated a large of amount of data which can be accessible and downloadable for stakeholder information. In total the amount of information is outlined as follows:

- Information on nine substation
- Information on 82 distribution feeders
- 17,391 nodes
- 6.66 GB
- 82 Downloadable ICA result files

The following outlines the major elements which had to be developed to accomplish the deliverables required by this projects:

1) Development of common bus and individual feeder CYME network models
2) Development of in-house Python scripts to collect and organize smart meter data
3) Development of in-house Python scripts to perform validation of data and models in preparation for the ICA calculation
4) Development of in-house Python scripts to perform the automated ICA on each of nodes on the distribution circuits
5) Development of in-house data extraction, transformation, and loading scripts to create file structures and databases to store, organize, and develop feeder data files
6) Development of an external-facing website to publicly share downloadable data
7) Development of an external-facing web application for load profile visualization
8) Development of new map layers to display information

To ensure that the data was the most accurate it could be, SCE performed several methods of data-accuracy testing:

9) Verification of limited output data via direct CYME simulation
10) Pattern and trend comparison for the various calculations and methodologies
11) Testing of data output at various stages of the project
    a) At early development of Python scripts
    b) At generation of data
    c) At preparation of final data files

The following explains the categories on the downloadable tables:

### TABLE 2: GENERAL CATEGORIES

| Table Category | Category Explanation |
|---|---|
| CIRCUIT_NAME | Name of the distribution feeder |
| SECTION_ID | Allows the section of a specific node |
| Load_Type | Allows the section of minimum or maximum values |
| MONTH | Allows filtering of all or selected months |
| HOUR | Allows filtering of all or selected hours |
| ICA_PV (kW) | Provides the ICA hourly data for fixed typical PV type |
| SCENARIO | Allows the selection of the three required scenarios (2-year growth, DRP scenario 1, and DRP scenario 3) |

### TABLE 3: ENERGY CONSUMING (LOAD) CATEGORIES

| Table Category | Category Explanation |
|---|---|
| STREAMLINED_THERMAL_LOAD (kW) | ICA values for the "Thermal" criteria using the Streamline methodology |
| STREAMLINED_STEADYVOLTAGE_LOAD (kW) | ICA values for the "Steady State" criteria using the Streamline methodology |
| STREAMLINED_ICA_LOAD (kW) | Final Load ICA for the Streamline Methodology |
| ITERATIVE_THERMAL_LOAD (kW) | ICA values for the "Thermal" criteria using the Iterative methodology |
| ITERATIVE_STEADYVOLTAGE_LOAD (kW) | ICA values for the "Steady State" criteria using the Iterative methodology |
| ITERATIVE_VOLTAGEFLUC_LOAD (kW) | ICA values for the "Voltage Fluctuation" criteria using the Iterative methodology |
| ITERATIVE_ICA_LOAD (kW) | Final Load ICA for the Streamline Methodology |

## TABLE 4: ENERGY PRODUCING (GEN) CATEGORIES

| Table Category | Category Explanation |
|---|---|
| STREAMLINED_THERMAL(kW) | ICA values for the "Thermal" criteria using the Streamline methodology |
| STREAMLINED_STEADYVOLTAGE (kW) | ICA values for the "Steady State Voltage" criteria using the Streamline methodology |
| STREAMLINED_VOLTAGEFLUC (kW) | ICA values for the "voltage fluctuation" criteria using the Streamline methodology |
| STREAMLINED_PROTECTION (kW) | ICA values for the "Protection" criteria using the Streamline methodology |
| STREAMLINED_SAFETY (kW) | ICA values for the "Safety/System flexibility" criteria using the Streamline methodology |
| STREAMLINED_ICA_GEN_REVERSE (kW) | Final ICA values for the "irrespective of power flow direction" requirement for the streamline methodology |
| STREAMLINED_ICA_GEN_NOREVERSE (kW) | Final ICA values for the "no reverser power flow at the substation busbar" requirement for the streamline methodology |
| ITERATIVE_THERMAL (kW) | ICA values for the "Thermal" criteria using the Iterative methodology |
| ITERATIVE_STEADYVOLTAGE (kW) | ICA values for the "Steady State Voltage" criteria using the Iterative methodology |
| ITERATIVE_VOLTAGEFLUC (kW) | ICA values for the "voltage fluctuation" criteria using the Iterative methodology |
| ITERATIVE_PROTECTION (kW) | ICA values for the "Protection" criteria using the iterative methodology |
| ITERATIVE_SAFETY (kW) | ICA values for the "Safety/System flexibility" criteria using the iterative methodology |
| ITERATIVE_ICA_GEN_REVERSE (kW) | Final ICA values for the "irrespective of power flow direction" requirement for the iterative methodology |
| ITERATIVE_ICA_GEN_NOREVERSE (kW) | Final ICA values for the "no reverser power flow at the substation busbar" requirement for the iterative methodology |

## 5.2. Representative ICA Results in Each DPA

Figure 26 shows the results of a typical 12KV circuit in the rural area. As can be observed, the ICA values on the nodes farthest away from the substation are generally lower than the ICA at nodes near the substation. It is typical that in most rural feeders, the steady state voltage and the operational flexibility criteria are the most limiting factors for nodes towards the end of the feeders.

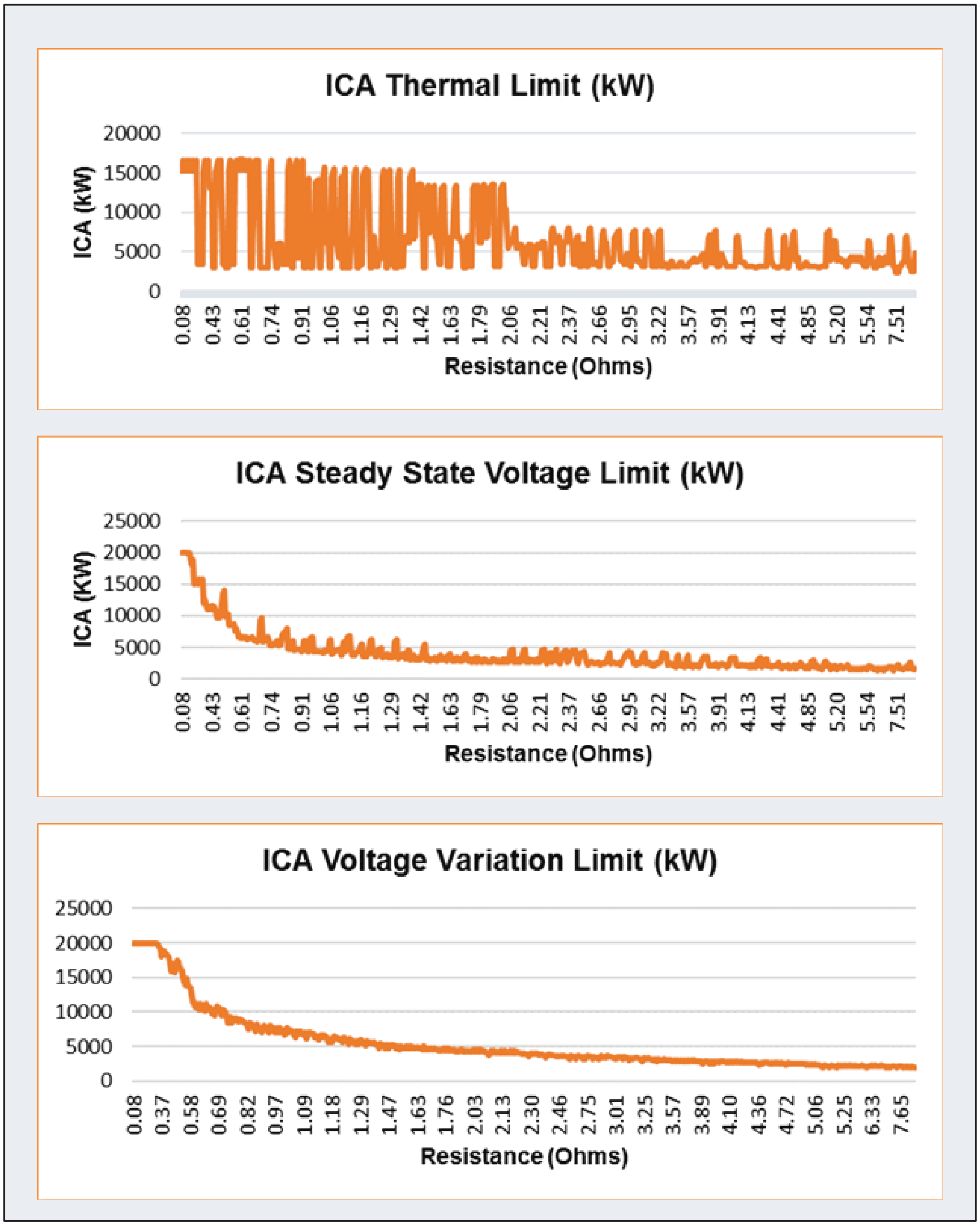
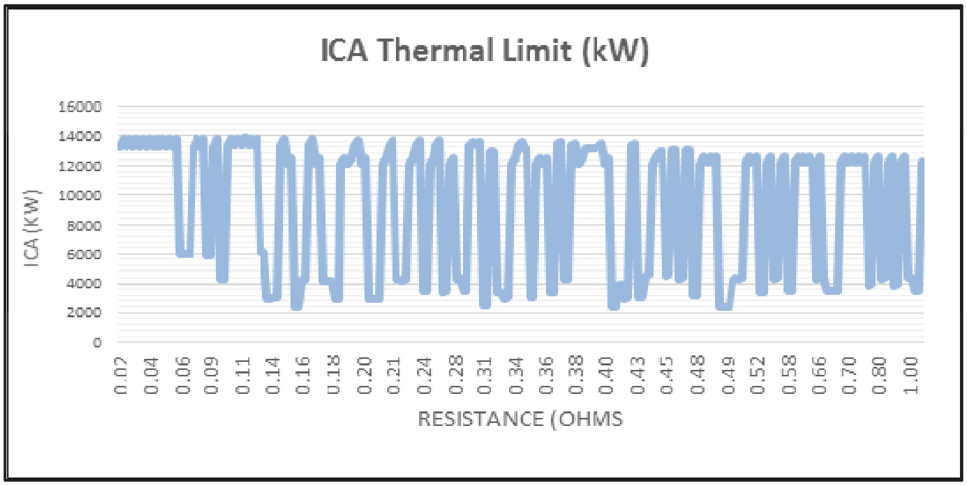
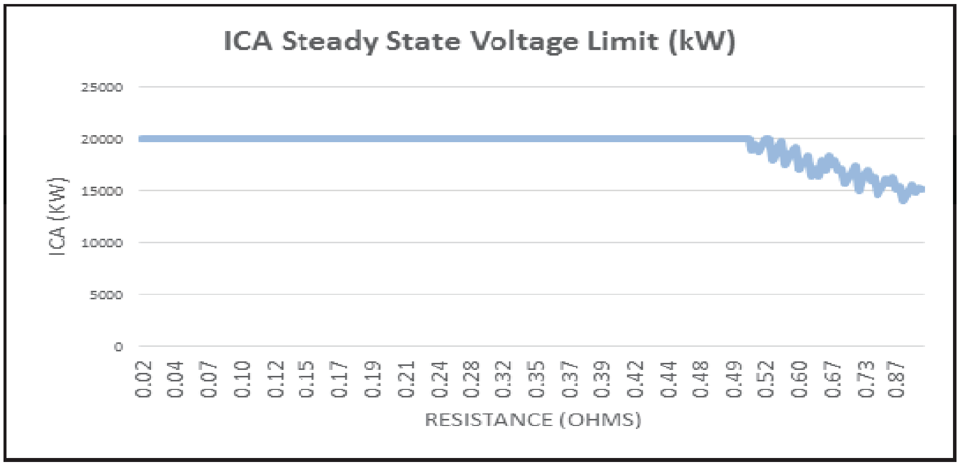



FIGURE 26: GEN ICA VALUES FOR TYPICAL FEEDER IN A RURAL DPA (CURTIS)

Figure 27 shows the results of a typical 12KV circuit in the Urban area. As can be observed, the ICA values for the nodes are high along most of the feeder. It is typical that in most urban feeders, the operation flexibility limitation would be the most limiting factor for nodes near the substation while the steady state voltage would commonly be the most limiting factor for nodes further away from the substation.



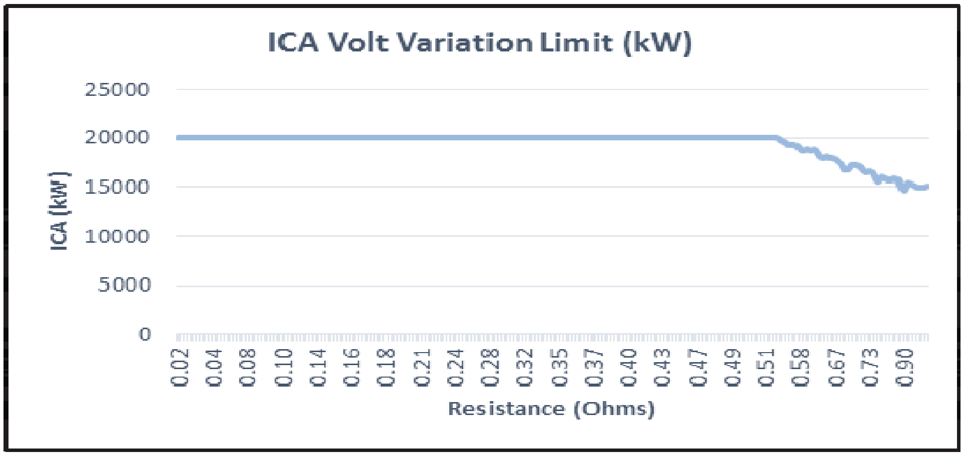




FIGURE 27: GEN ICA VALUES FOR TYPICAL FEEDER IN A URBAN DPA (COBALT)

## 5.3. Methodology Comparison Results

Figure 29 through Figure 33 shows a set of graphs which depict the results between the Iterative Method and Streamlined Method for the urban and rural DPAs for each limiting category.

In these figures, the **solid green bar** represents ***average of the minimum values*** of all the feeders. This solid green value can be looked at as the value which can be connected anywhere in the DPA without exceeding the category limit. The **solid yellow bar** represents a value that is the ***average of the maximum values*** which indicates that some feeders can accept this level of ICA, based on location of interconnection, without exceeding the category limiting factor while the **solid red bar** represents a value that **exceeds the *average of the maximum values*** which indicates the high likelihood of exceeding the category limit. The solid bar indicates the true average of the values based on the category and methodology. The grey bars represent the averages of both systems, darker to lighter analogous to green to red colors. This is further explained in Figure 28, which provides a visual representation.

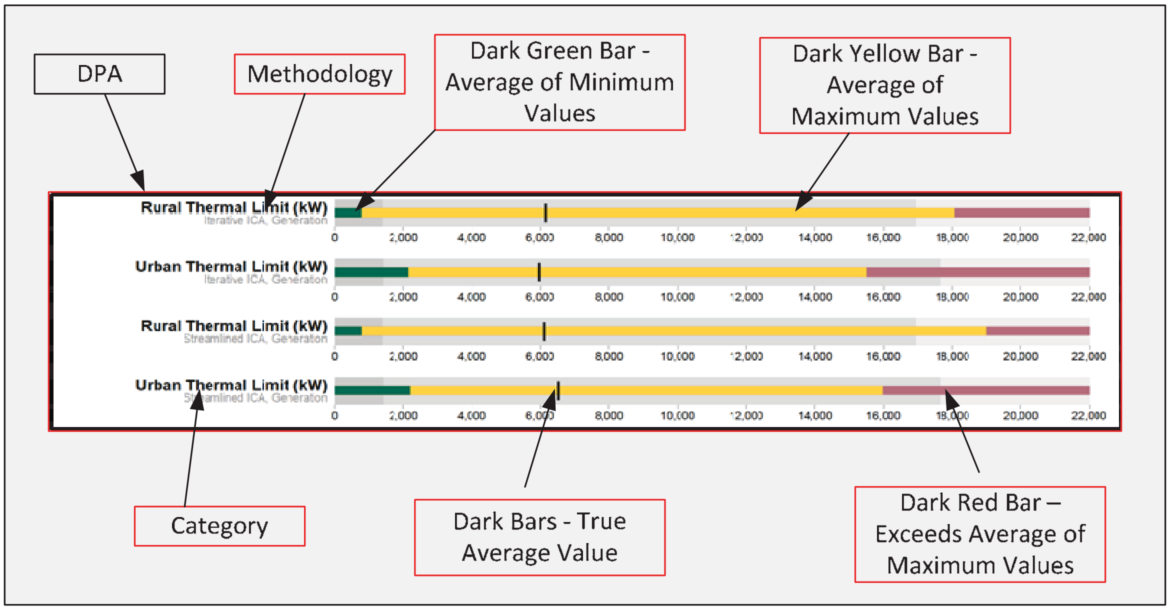



FIGURE 28: SAMPLE OF REPRESENTATION OF DATA

Figure 29 shows that based on the thermal limiting category, the urban DPA is generally able to accept higher levels of DER across it feeders without exceeding the thermal limit (green solid bar). Both the Streamlined Method and Iterative Method are consistent in that aspect for both DPAs.


FIGURE 29: THERMAL LIMIT- ITERATIVE VS STREAMLINED COMPARISON

Figure 30 shows that based on the Steady State Voltage (SSV) limiting category, the urban DPA is generally able to accept higher levels of DER across its feeders (green solid bar). Both the Streamlined Method and Iterative Method are consistent in that aspect for both DPAs.

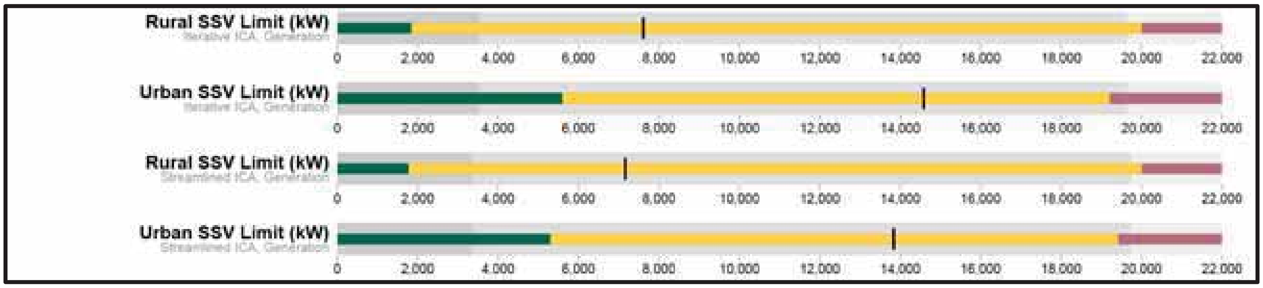



FIGURE 30: STEADY STATE VOLTAGE LIMIT- ITERATIVE VS STREAMLINED COMPARISON

Figure 31 shows that based on the Voltage Fluctuation limit category, the urban DPA is generally able to accept higher levels of DER across its feeders (green solid bar). Both the Streamlined Method and Iterative Method are consistent in that aspect for both DPAs.


FIGURE 31: VOLTAGE FLUCTUATIONS LIMIT- ITERATIVE VS STREAMLINED COMPARISON

Figure 32 shows that based on the protection limit category, the Iterative Method is able to accept significantly higher levels of DER then the streamlined Method. This has to do with the fact that the Streamlined Method is using a heuristic 10% approach to calculate this value while the Iterative Method is performing actual fault flow calculations to determine the value.


FIGURE 32: PROTECTION LIMIT- ITERATIVE VS STREAMLINED COMPARISON

Figure 33 shows that based on the safety limit category, the Streamlined and Iterative Methods return equivalent results. This is due to the nature of the limitation category: allowing generation and load to downstream of strategic devices to equal, allowing for the dynamic operation of the distribution system in lieu of complete visibility and control over DER.


FIGURE 33: SAFETY LIMIT- ITERATIVE VS STREAMLINED COMPARISON

# 6. Comparative Assessment

## 6.1. General Description

Demo A demonstrates the use of a Streamlined Method as well as an Iterative Method for the calculation of ICA. A comparative assessment of these two methodologies illustrates the differences between the two methods, as well as the strengths and weaknesses of each approach to provide a foundation for proposing a final ICA methodology. In addition, it is also essential to conduct a comparative assessment among different IOUs to ensure that the ICA methodologies applied are common across all utilities, so that ICA values are being calculated in a consistent manner from one utility to another.

## 6.2. Comparison between Two Methods

### 6.2.1. Approach

The Streamlined Method calculates the DER integration capacity at each node using mathematical equations for each of the limiting factors. For simplicity, the Streamlined Method uses extracted physical characteristics from the baseline power flow simulation. These characteristics include resistance and voltage, which then are used as inputs to the streamlined mathematical equations. The Streamlined Method may not properly capture some detailed variations across the entire network model. On the other hand, the Iterative Method utilizes detailed power flow analyses to calculate the DER integration capacity which captures the variations on the entire network model but requires a significant amount of computing resources. The comparison between the Streamlined and Iterative Methods focuses on the consistency of the ICA results and the computing resources required by these two methodologies.

The ICA results from both methods are first examined for each circuit in the selected DPAs to understand the general patterns, trends, and potential exceptions. A comparison between the two methods is then performed by individual power system limitation category in order to gain a better understanding of the difference in results for each limiting category.

### 6.2.2. Findings

*Thermal*

In general, it was observed that for the thermal rating criteria, the Iterative Method produces slightly higher integration capacity than the Streamlined Method for energy producing resources (generation) and the Streamlined Method produced higher integration capacity for energy consuming resources (Load) then the Iterative Method. The typical pattern is shown in Figure 34. In relation to higher difference on the load ICA, this occurs because the Streamlined Method does not accurately represent the load flow along the feeder line segments as load DER level is increased, while the Iterative Method more accurately monitors the power flow conditions along the feeder as load DER is being increased to its maximum value. The variance of thermal ICA values is a function of the complexity of the feeder, and in some cases, the variance can be significant as shown in Figure 35.

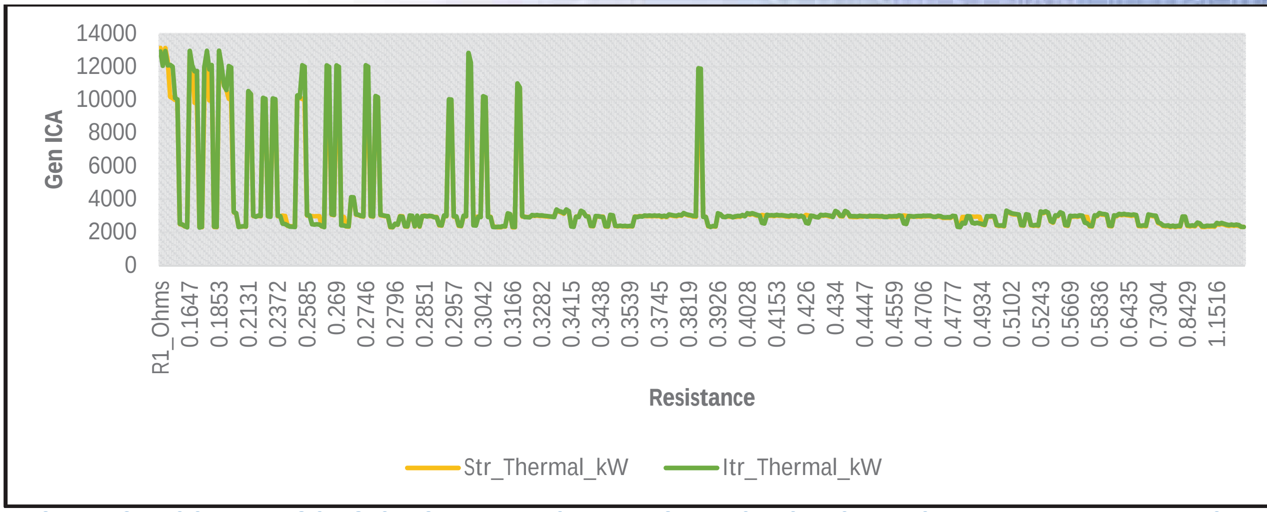



FIGURE 34: COMPARISONS OF GENERATION INTEGRATION CAPCITY FOR THERMAL LIMITATION (CHEESE 12KV FEEDER)

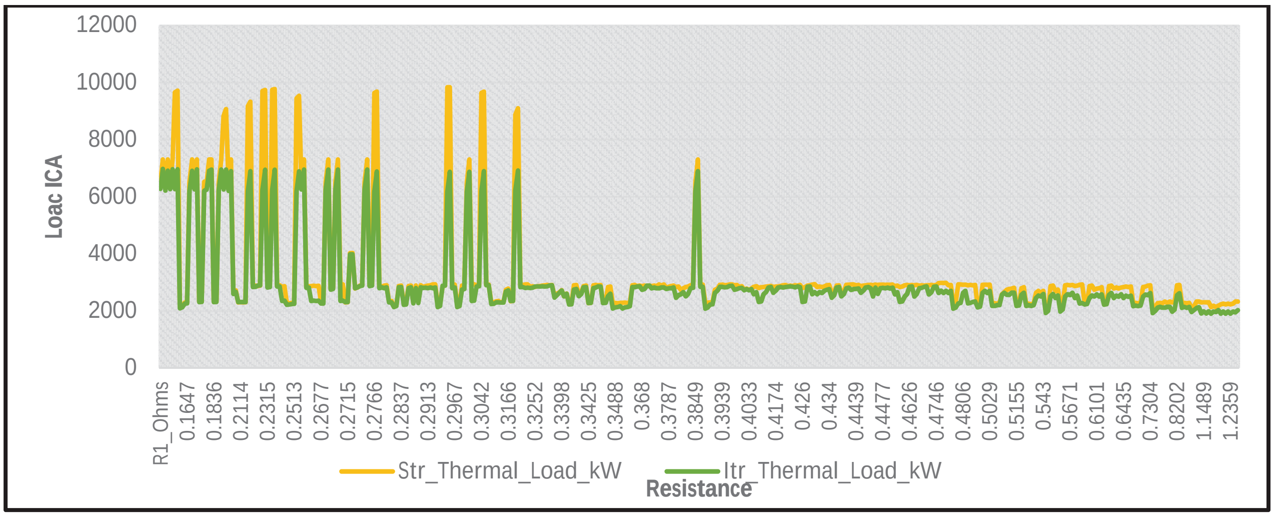


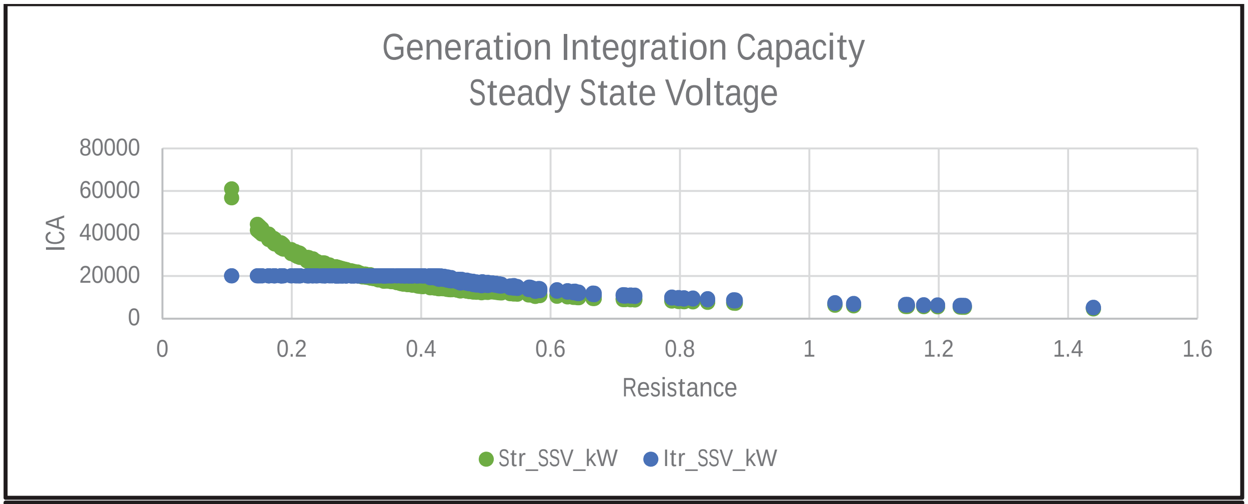

FIGURE 35: COMPARISONS OF LOAD INTEGRATION CAPCITY FOR THERMAL LIMITATION (CHEESE 12KV FEEDER)

### *Steady State Voltage*

For the Steady State Voltage criteria, as the node being analyzed is located further away from the substation, the line impedance between the node and substation increases, which leads to DER causing greater impact on the feeder steady-state voltage profiles. As a result, the DER which can be interconnected without triggering the steady state voltage flag generally decreases as the location of the node being analyzed is further away from the substation.

Figure 36 shows the integration capacity values for energy producing resources (Gen) and for energy consuming resources (load) due to steady state voltage limitation on a 12kV feeder for the Streamlined Method and the Iterative Method.  As it can be observed, the highest difference occurs on nodes close to the substation.  However, the Streamlined Method and the Iterative Method generally produce equivalent values of ICA at nodes towards the end of the feeder.  This pattern is observed throughout most feeders in the both DPAs being studied.

As stated in section 4.4, SCE limited the iterative ICA value to 20 MW for computation efficiencies and is the reason why there is a flat line limit at 20 MW observed from 0Ω to 0.4Ω in Figure 36. The Iterative Method consistently produces a higher integration capacity value than the Streamlined Method, but the difference of the integration capacity between two methods reduces as the node being analyzed is further towards the end of feeder.



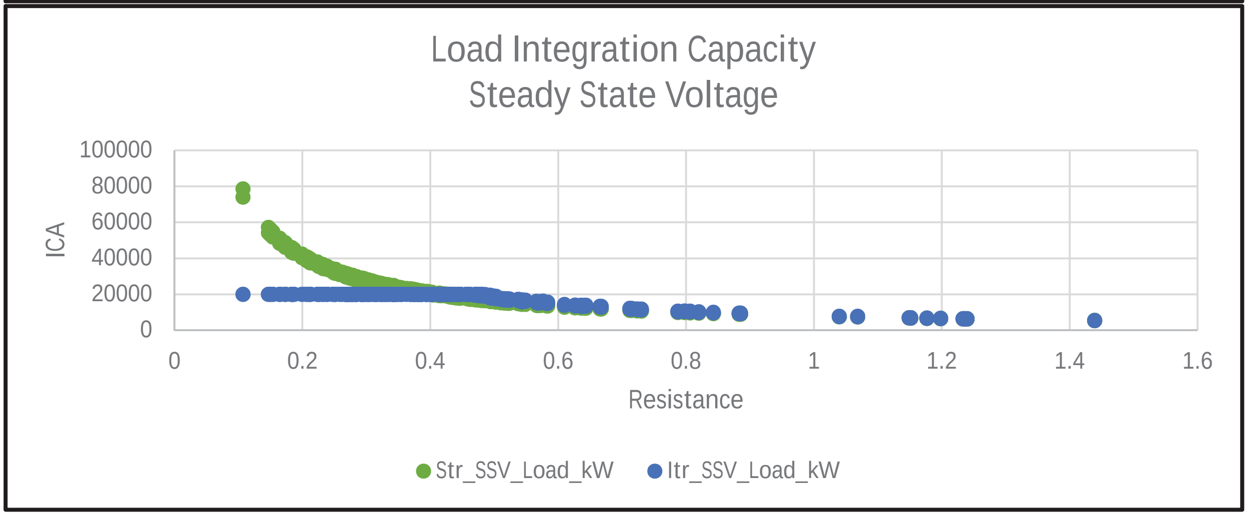




FIGURE 36: COMPARISONS OF INTEGRATION CAPCITY DUE TO STEADY STATE VOLTAGE LIMITATION (BILLING 12KV FEEDER)

### *Voltage Fluctuation*

Voltage Fluctuations criteria generally behaves in similar pattern to the steady state voltage criteria. As the node being analyzed is located further away from the substation and the line impedance between the node and substation increases, the DER causes greater impact on the feeder voltage fluctuation criteria. As a result, the DER that can be interconnected without triggering the voltage fluctuations flag generally decreases as the location of the node being analyzed is further away from the substation.

Figure 37 shows the comparison of the integration capacity values due to the voltage fluctuation criteria for a 12kV feeder. Similar to the pattern observed for the steady state voltage criteria, this pattern is observed throughout the study areas with very few exceptions. The integration capacity is very high at nodes close to the substation. Depending on each circuit's characteristics, the values can be greater than 20MW (i.e., the cap value in Demo A). When the node being analyzed is located further away from the substation, the voltage fluctuation integration capacity values decrease. The Iterative Method consistently produces a higher integration capacity value than the Streamlined Method, but the difference of the integration capacity between two methods reduces as the node being analyzed moves towards the end of feeder.

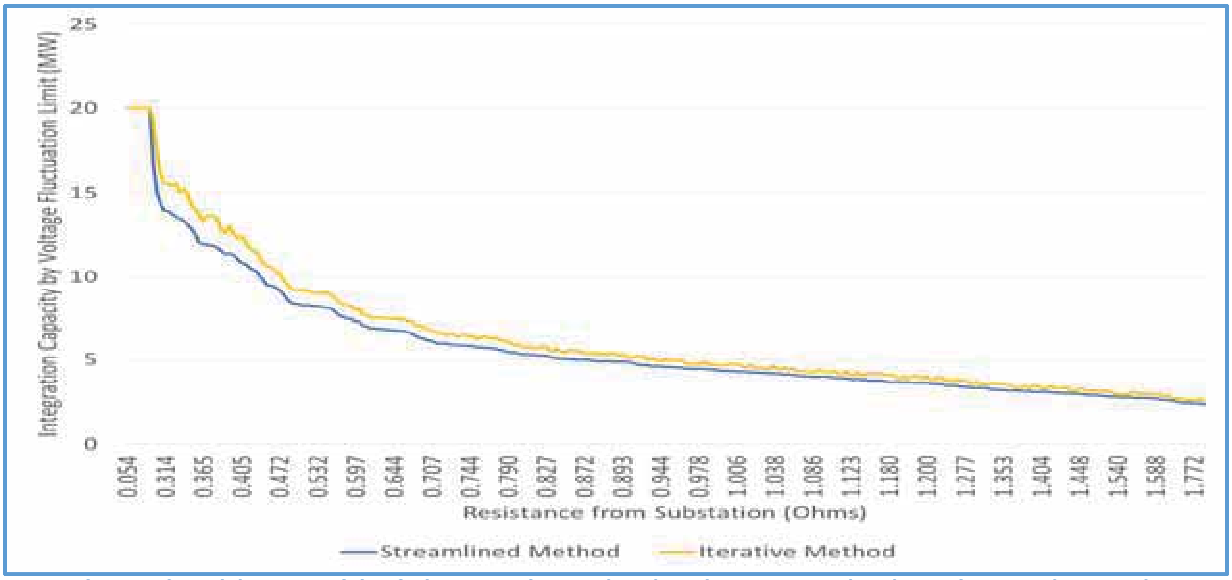



FIGURE 37: COMPARISONS OF INTEGRATION CAPCITY DUE TO VOLTAGE FLUCTUATION LIMITATION (AURORA 12KV FEEDER)

### *Statistical Comparison*

A statistical analysis was performed applied to all the results to estimate the level of significance difference between the results from the Streamlined Method to the Iterative Method. The following figures provide various statistical data to show the comparison between the Iterative Method and the Streamlined Method.

Figure 38 shows average for each category as well as the average delta for each category. As Table 5 shows, the values for energy consuming resources (generation) the delta between the Iterative Method and the Streamlined Method are not significant. However, the load ICA values do have a significant difference between the Streamlined and Iterative Methods. For the load ICA, the difference is that the Iterative Method is more effectively able to determine limitation on the entire network then the Streamlined Method is able to thorough the use of the streamlined equations.

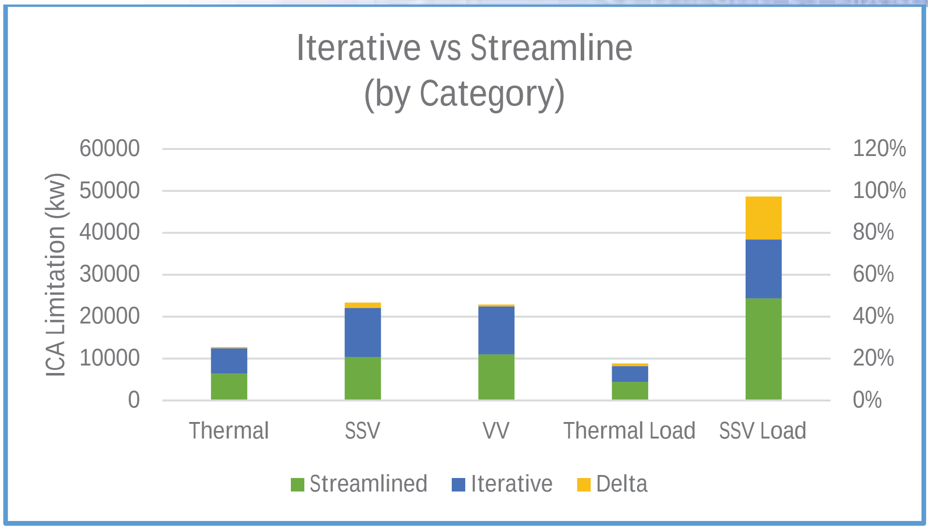



FIGURE 38: % COMPARISON ON THERMAL LIMITATION (KW)

TABLE 5: ITERATIVE VS STREAMLINED SUMMARY TABLE (KW)

| Category | Streamlined | Iterative | Delta | % Diff |
|---|---|---|---|---|
| Thermal | 6373 | 6090 | 283 | 4% |
| SSV | 10368 | 11681 | 1312.5 | -13% |
| VV | 10991 | 11451 | 460 | -4% |
| Thermal Load | 4419 | 3757 | 662 | 15% |
| SSV Load | 24337 | 14073 | 10263.5 | 42% |
| **Total** | **11297** | **9410** | **1887.2** | **17%** |

## 6.3. Computation Performance

Figure 39 shown the computation performance of each of the feeders on Demo A. As it can be seen from Figure 39, the time require to perform the iterative calculation is significantly more than the time required to perform the Streamlined Method. This is because the Iterative Method performs large numbers of simulations per hour as required to provide the most accurate ICA calculation while the Streamlined Method only performs one simulation per hour to extract the data necessary to estimate the value ICA based on streamlined equations. Also the figure shows that each feeder is unique, where the solution for one circuits was reached within minutes while other circuits required hours to complete.

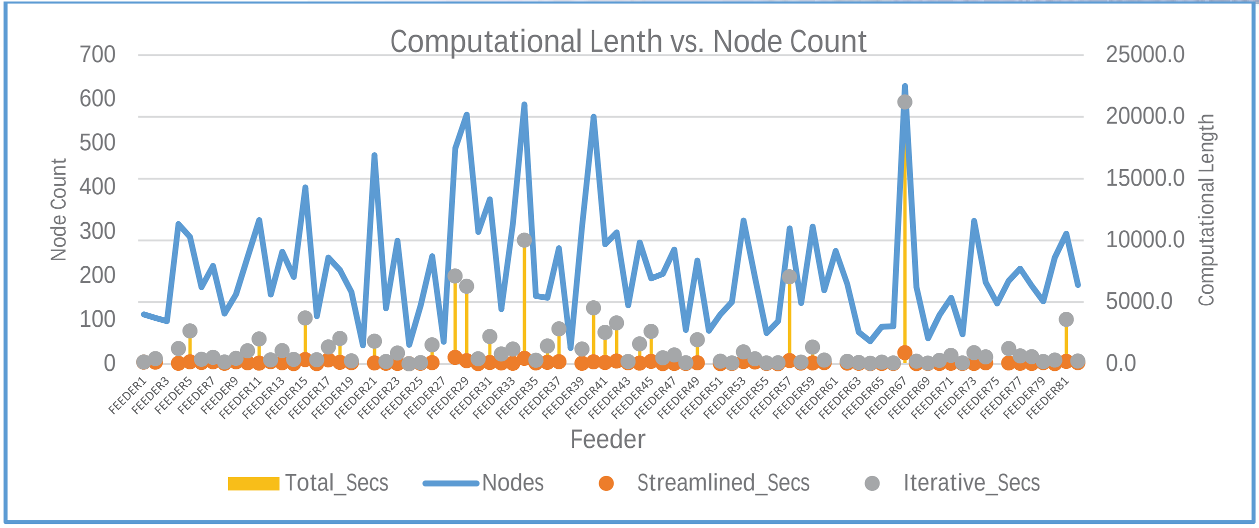



FIGURE 39: COMPUTATION LENGTH OF EACH FEEDER

## 6.4. Comparison among IOUs

The comparative assessment began with analyzing the IEEE 123-node feeder, in order to ensure general alignment with an easy to review data set. Utilizing this smaller dataset was important as it identified the complexity of the methodologies being evaluated. Starting with a complex dataset for comparison purposes would have been too much of a time burden. Two main challenges were found in the process. The first was making sure the models were identical, and the second was ensuring all the starting points and power flow settings were the same.

The power flow tools allow for the vast amounts of settings and parameters in order for models to simulate the specific conditions necessary for evaluation. The IOUs have learned many aspects of the parameters of the tools used which allowed the IOUs to drive toward better alignment in the technical assumptions that go into the power flow.

### 6.4.1. Approach

During this comparative assessment, the Streamlined and Iterative ICA results are compared between IOUs to ensure alignment on the methodologies, assumptions and simulation parameters.

The IOUs adopted the IEEE 123 node test feeder as the reference feeder for this comparison. The IEEE 123 node test feeder has an established data set of power flow results and is publicly available for stakeholders to test and verify results. This test feeder is characterized by both overhead and underground lines, unbalanced loading with constant current, impedance and power. It operates at a nominal voltage of 4.16 kV (which is not the most commonly used voltage level) and provides voltage drop issues that must be solved with voltage regulation applications such as voltage regulators and shunt capacitors.

SCE and PG&E use CYMDIST as their power system analysis tool while SDG&E uses Synergi as its power system analysis tool. For this reason, the power flow results between these two tools were first compared to ensure simulation environment consistency. The ICA results are then analyzed with the understanding of any error margins existing in the power flow models.

### 6.4.2. Findings/Conclusions

Challenges in model alignment were first resolved by ensuring the base dataset was properly coded in the dataset required by both power flow tools. PG&E and SCE were able to align on an already established circuit model from CYME, however, Synergi had not previously established such a model and it had to be created prior to commencing the comparison process. Once created, some differences in how the tools handle some components provided some variation. For power flow, the main issue was the modeling of the voltage regulator. While variation has been reduced to a minimal amount, it is still being evaluated to determine why CYME and Synergi assume different impedances for the regulator.

The other differences were around the starting assumptions and parameters that can be used for the power flow tools. The utilities collaborated to align on many of these values which are:

- Power Flow Calculation Method;
- Convergence Parameters;
- Line Transposition and Charging;
- Voltage Sensitivity Load Models;
- Regulator Tap Operation Models;
- Starting Voltages;
- Pre-Fault Voltages.

Another component of this is the various amounts of electrical values that can be retrieved from the tool to analyze such as:

- A/B/C Phase Voltages;
- Min/Max/Avg Voltages Real and Apparent Power.

*Model Comparison*

As shown on Figure 40 through Figure 43, it was observed that there is a slight deviation across a few characteristic with how CYME and Synergy solve the model. The IOUs were confident that the magnitude of these differences was not significant enough to warrant issues. Below are a few graphs showing the comparison between the Synergi and CYME model simulations.

Figure 40 shows that CYME typically calculates a higher 3-phase short circuit duty value then Synergy by an average of 13%. As it can be observed in the Figure 40, the difference decreases as a function of distance from substation to the nodes.

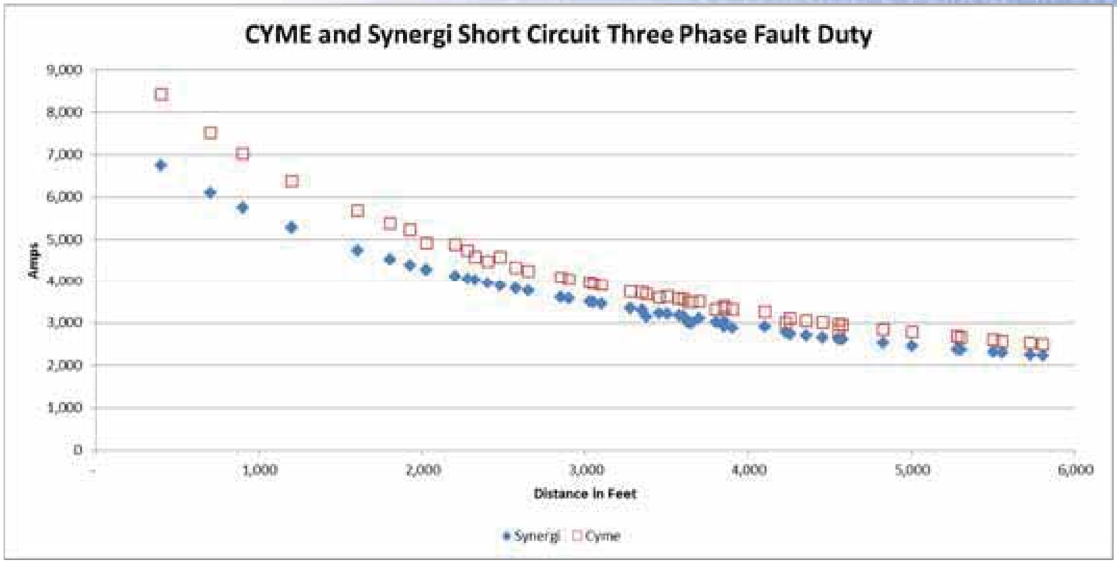



FIGURE 40: SHORT CIRCUIT FAULT DUTY COMPARISON WITH AVERAGE DIFFERENCE OF 13%

Figure 41 shows that CYME typically calculates a slightly higher average steady state voltage then Synergy by an average of 0.43%. As it can be observed, the difference across the nodes in the test feeder is generally constant.

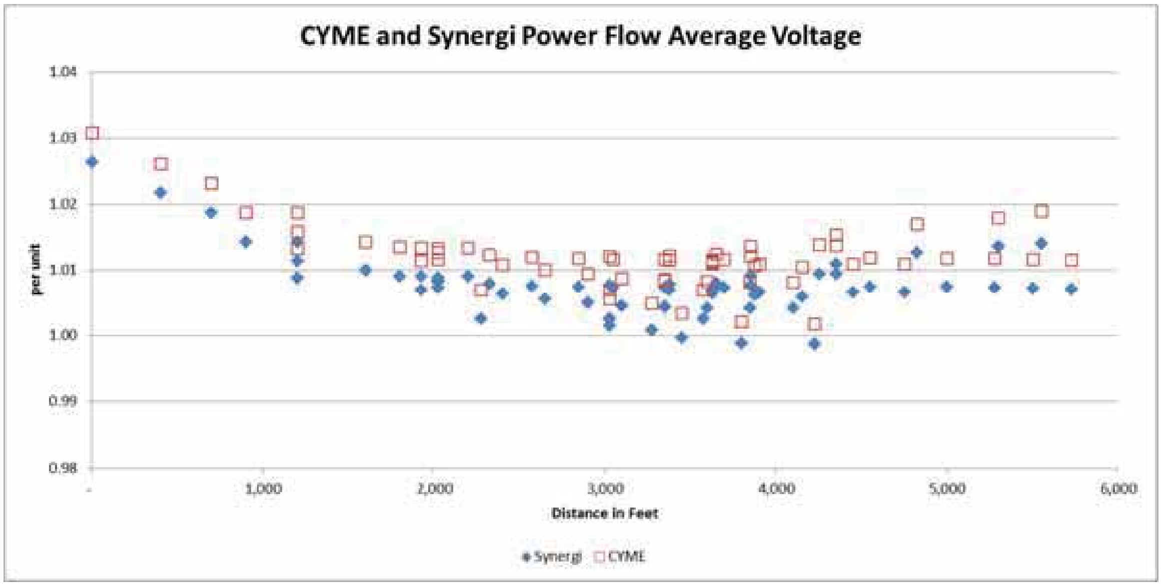



FIGURE 41: AVERAGE VOLTAGE COMPARISON WITH AVERAGE DIFFERENCE OF 0.43%

Figure 42 shows that CYME typically calculates a slightly higher maximum steady state voltage then Synergy by an average of 0.5%. As it can be observed in the figure below, the difference across the nodes in the test feeder is generally constant.

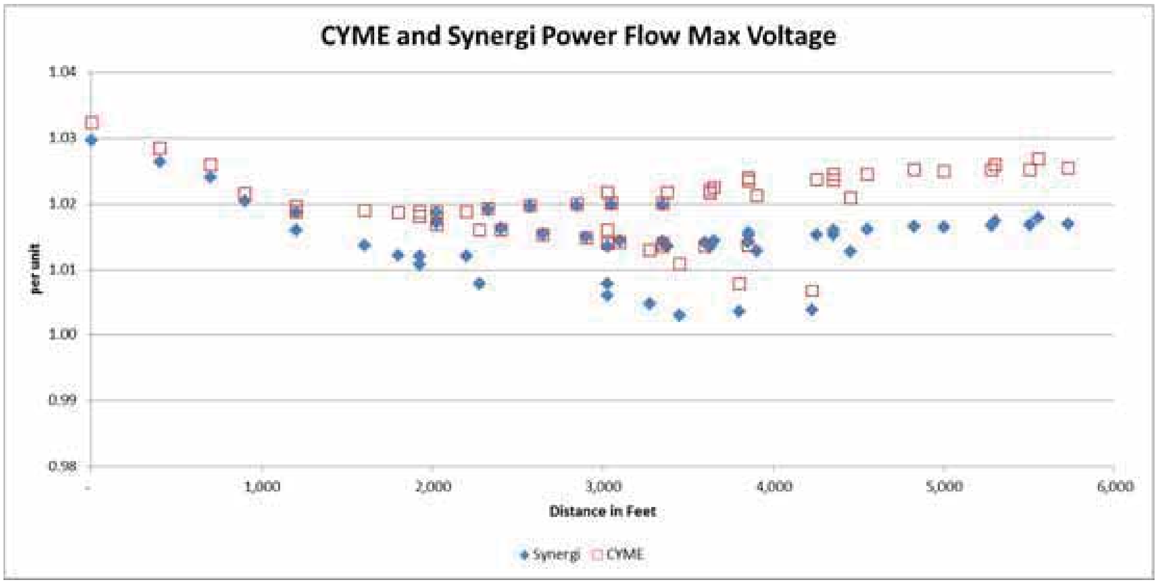



FIGURE 42: MAXIMUM VOLTAGE COMPARISON WITH AVERAGE DIFFERENCE OF 0.5%

Figure 43 shows that the both Synergy and CYME typically aligned on the calculation of power flow through each node with an average difference of 0.3%.

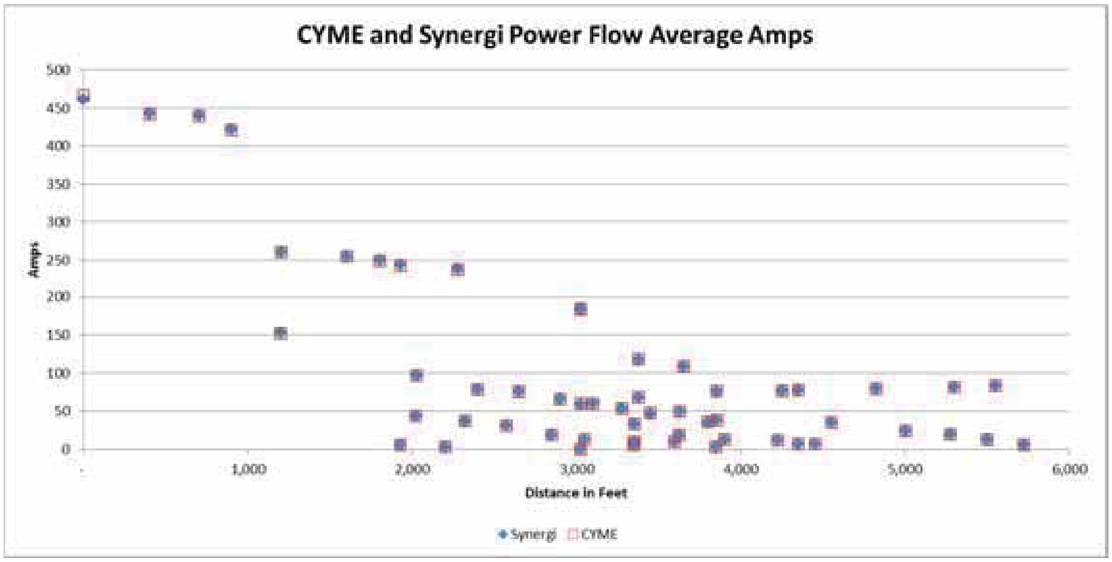



FIGURE 43: AVERAGE AMPS COMPARISON WITH AVERAGE DIFFERENCE OF 0.3%

### *Streamlined Method Comparison*

The following figures depict the comparison of the Streamlined Method results for the IEEE123 feeder across the three IOUs. Overall the IC values track each other similarly and do not have significant variation. The slight variation is attributed to the variation in how power flow models are treated between CYME and Synergy.

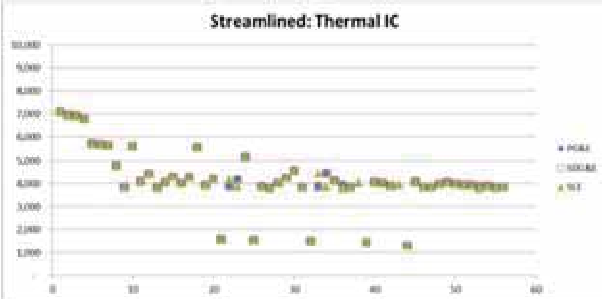



FIGURE 44: STREAMLINED THERMAL IC COMPARISON

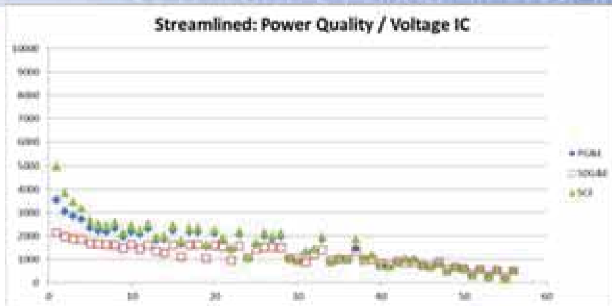



FIGURE 45: STREAMLINED PQ IC COMPARISON

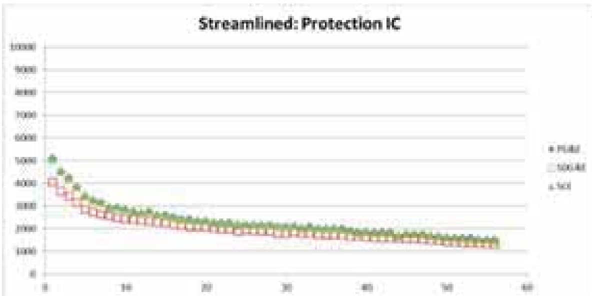



FIGURE 46: STREAMLINED PROTECTION IC COMPARISON

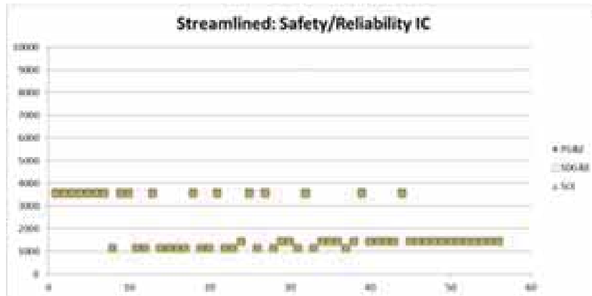



FIGURE 47: STREAMLINED S/R IC COMPARISON

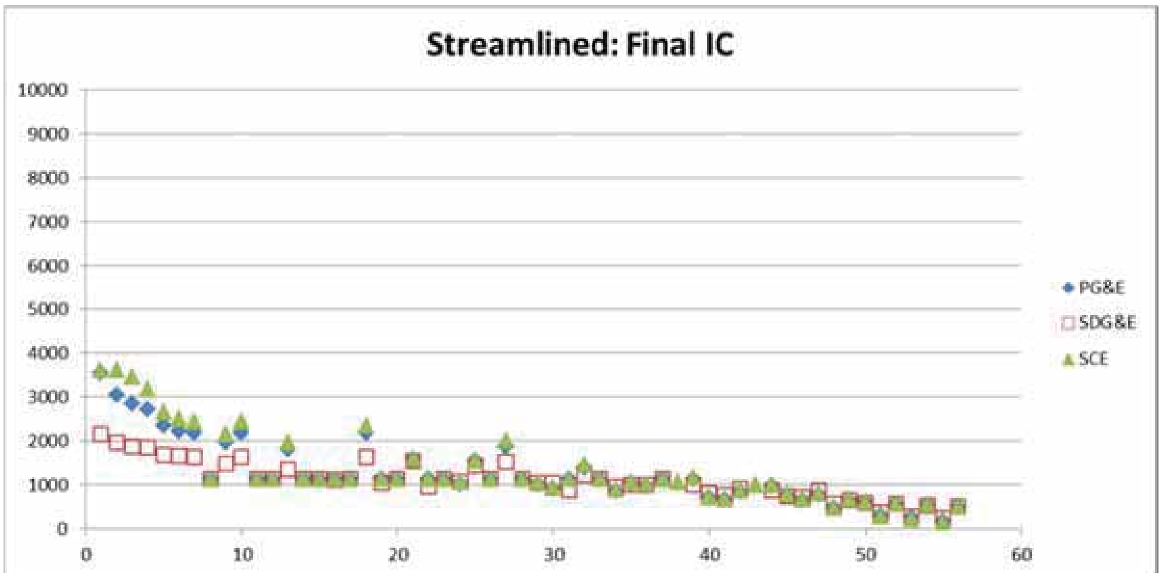



FIGURE 48: STREAMLINED FINAL IC COMPARISON

## *Iterative Comparison*

The following figures depict the comparison of the Iterative Method results for the IEEE123 feeder across the three IOUs. Overall, the IC values track each other similarly and don't have significant variation. The minor variation seen is attributed to the variation in how power flow models are treated between CYME and Synergy.

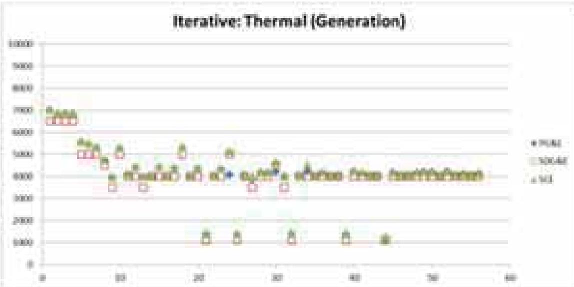



FIGURE 49: ITERATIVE THERMAL IC COMPARISON

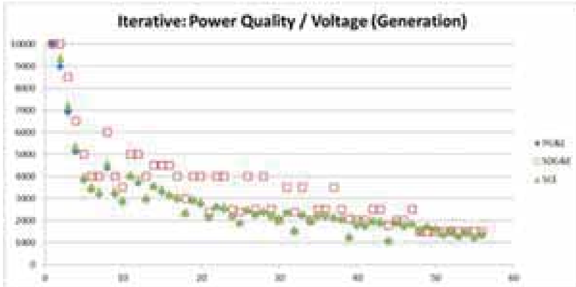



FIGURE 50: ITERATIVE PQ IC COMPARISON

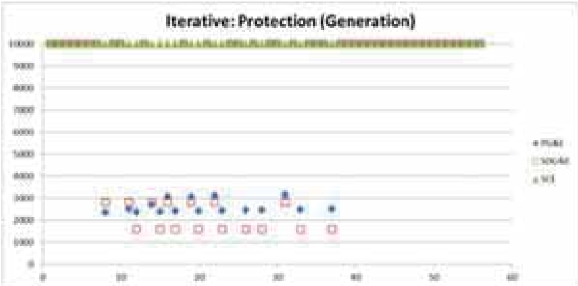



FIGURE 51: ITERATIVE PROTECTION IC COMPARISON

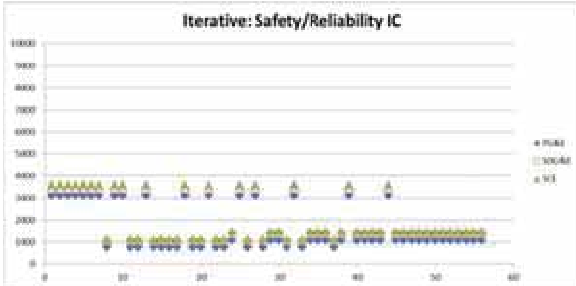



FIGURE 52: ITERATIVE S/R IC COMPARISON

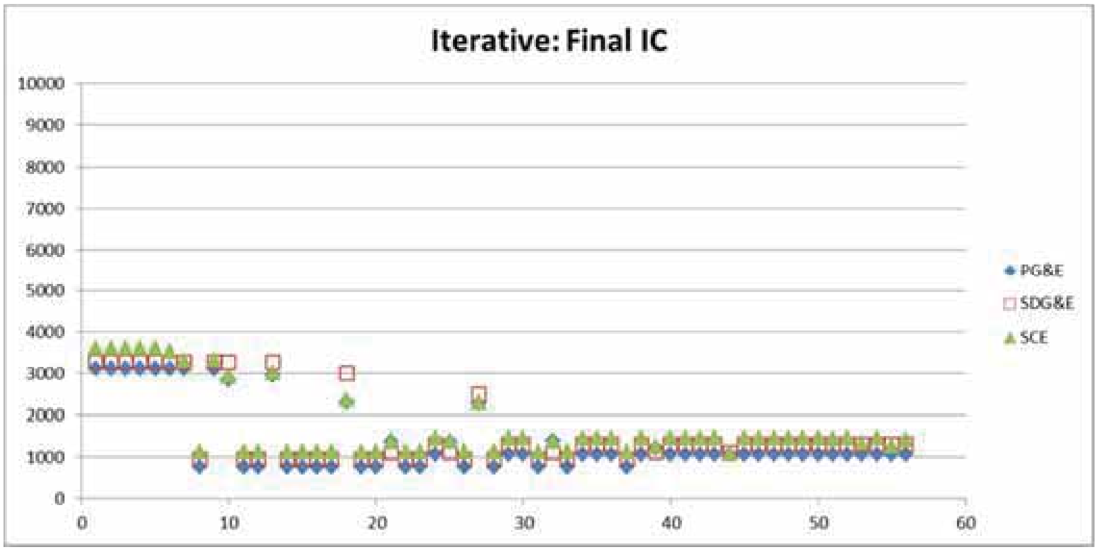



FIGURE 53: ITERATIVE FINAL IC COMPARISON

# 7. Map Display

## 7.1. General Description

The results of DRP Demo A Project have been published as additional layers within SCE's existing Distributed Energy Resource Interconnection Map (DERiM). In addition, SCE has launched an ArcGIS Online Web Application to publish interactive load profiles for circuits, substations, and DPAs (http://on.sce.com/derimwebapp). SCE's existing DERiM User Guide has been expanded to include Demo A Definitions (http://on.sce.com/derimguide). Lastly, SCE will publish comprehensive downloadable result files, by circuit, to a new webpage referred to as the DRP Demo Results Library (http://on.sce.com/drpdemos).

5. DERiM Web Map: http://on.sce.com/derim
6. DERiM Web App (load profiles): http://on.sce.com/derimwebapp
7. Expanded DERiM User Guide: http://on.sce.com/derimguide
8. DRP Demo Results Library: http://on.sce.com/drpdemos

DERiM is an interactive web map developed on ESRI's ArcGIS online platform. It performs calculations by collecting data from a variety of sources, such as cGIS (line routes and substation locations), Generation Interconnection Tool (interconnection queue), and Master Distribution Interface (forecast and equipment capacity). DERiM aims to provide the public with the SCE system data necessary to enable strategic DER siting. Users click on map features to obtain a variety of results, including ICA results. All of the information published to the map or downloadable files will be subject to Personal Identifiable Information (PII) or Critical Energy Infrastructure Information (CEII) compliance requirements.

### 7.1.1. Results Display Plan

As indicated in SCE's Demo A Intermediate Status Report[22], the total amount of data to be generated in Demo A is significant. Publishing all of this data on the map could negatively affect the user experience by creating longer loading times, and exposing a high volume of non-actionable data. Iterative ICA results from the 2-year growth, no-reverse at the substation busbar scenario will be published to DERiM. The uniform generation integration capacity, the uniform load integration capacity, and integration capacity for typical PV systems will be published to DERiM. The ICA for typical PV systems is based on the most limiting hour using typical PV shape consistent with Rule 21 practices. The remainder of the results, including the integration capacity values under DER growth scenarios I and III, and streamlined integration capacity values will be provided in a downloadable format accessible from a link in map interface.

Map symbology, also known as the heat map visualization, will be based on the integration capacity values for uniform generation, as described above. The uniform generation integration capacity value shown in the map is the "final" ICA result based on the most limiting power system criteria at the most limiting hour. Red colors represent areas of low integration

[22] Southern California Edison Company's (U 338-E) Intermediate Status Report for Demonstration Project A, September 30, 2016.

capacity, while green areas represent areas of high integration capacity. At the time of this report, the following symbology ranges have been developed for the purposes of Demo A ICA.

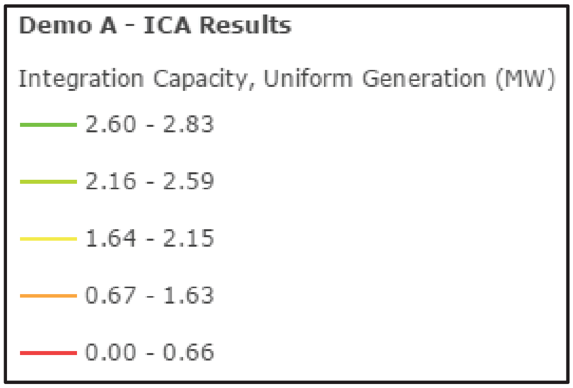



FIGURE 54: ICA COLOR RANGES

Besides the scenarios shown in the DERiM, users can download the complete Demo A dataset for each circuit from the DRP Demo Results Library. SCE will also publish downloadable files for DPA load profiles, substation load profiles, circuit load profiles, DERiM User Guide, and the ICA Translator. Please refer to the DERiM User Guide for step-by-step instructions to download DERiM data. The ICA Translator is an excel based tool which SCE will make available for users to be able to transform the agonistic ICA DER profiles into technology or portfolio specific ICA values.

The downloadable files for each circuit will be stored in a universal file format that can accommodate the large volume of data, such as a *.csv.

### 7.1.2. Map Design

The following layer descriptions provide an overview of the features (graphic representation), attributes (data obtained through pop-up or otherwise) and symbology (how colors and symbols are applied to the features) within the Demo A layers.

## Demonstration Projects A & B: Display of DPA areas

| *Layer* | **Demo A & B - DPA** |
|---|---|
| *Features* | Buffer area encompassing the extent of all distribution circuits within each DPA |
| *Attributes* | -DPA<br>-[Link] DERiM User Guide<br>-[Link] DERiM WebApp (Load Profiles)<br>-[Link] DRP Demo Results Library |
| *Symbology* | Unique (random) |
| *Symbology Key* | DPA Name |

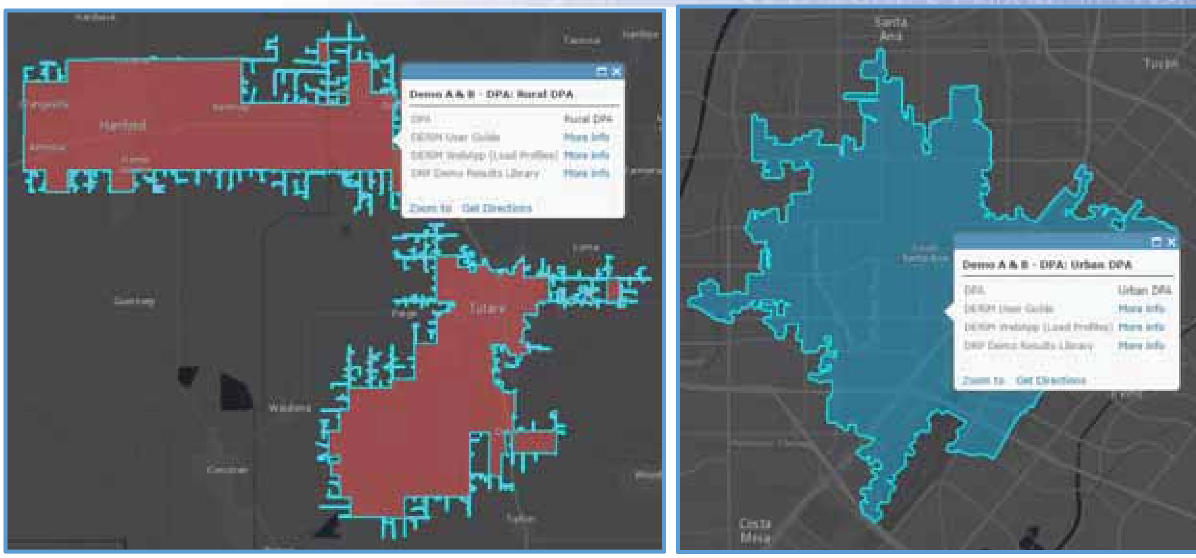



FIGURE 55: DPA LAYER (LEFT- RURAL, RIGHT-URBAN)

## Demonstration Projects A & B: Display of Substations

| *Layer* | **Demo A & B - Substations** |
|---|---|
| *Features* | Point locations for substations |
| *Attributes* | -Substation<br>-System<br>-Existing Generation (MW)<br>-Queued Generation (MW)<br>-Total Generation (MW)<br>-[Link] DERiM User Guide<br>-[Link] DERiM WebApp (Load Profiles)<br>-[Link] DRP Demo Results Library |
| *Symbology* | Single symbol |
| *Symbology Key* | N/A |

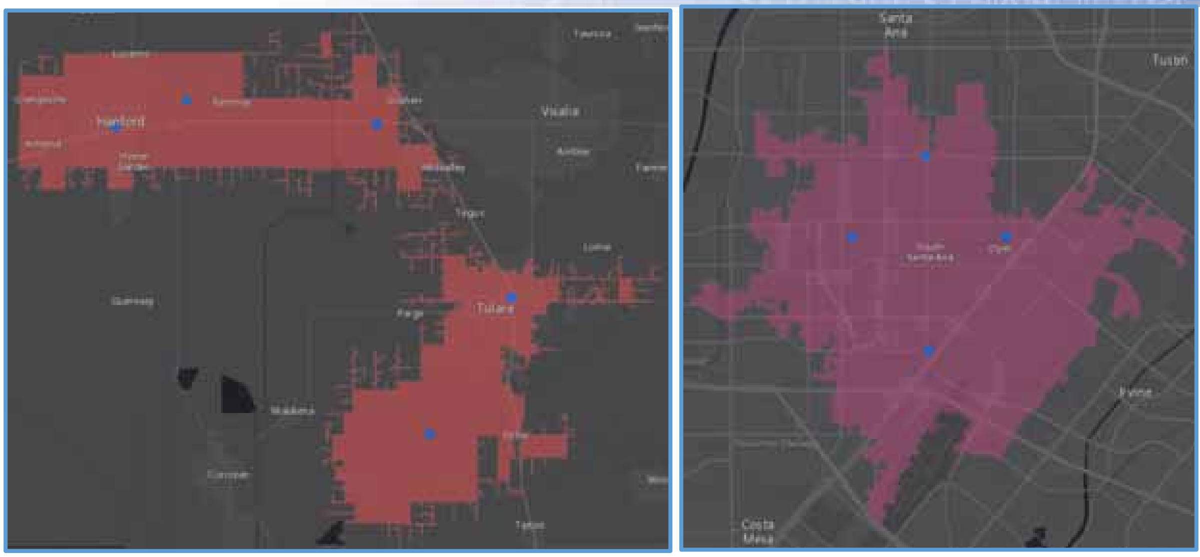



FIGURE 56: SUBSTATIONS LAYER (LEFT- RURAL, RIGHT-URBAN)

(1 of 2)

**Demo A & B - Substations: Goshen 66/12 kV**

| | |
|---|---|
| Substation | Goshen 66/12 kV |
| System | Rector 220/66 System |
| Existing Generation (MW) | 4.60 |
| Queued Generation (MW) | 2.25 |
| Total Generation (MW) | 6.84 |
| DERiM User Guide | More info |
| DERiM WebApp (Load Profiles) | More info |
| DRP Demo Results Library | More info |

FIGURE 57: SUBSTATION POP-UP

## Demonstration Project A: Load Profiles & Customer Type Breakdown

| *Layer* | **Demo A – Load Profiles & Customer Type Breakdown** |
|---|---|
| *Features* | 3-phase primary conductor as a single contiguous feature by circuit |
| *Attributes* | -Circuit<br>-Voltage (kV)<br>-Substation<br>-System<br>-Agricultural (%)<br>-Commercial (%)<br>-Industrial (%)<br>-Residential (%)<br>-Other (%)<br>-Existing Generation (MW) |

| | |
|---|---|
| | -Queued Generation (MW)<br>-Total Generation (MW)<br>-Note<br>-[Link] DERiM User Guide<br>-[Link] DERiM WebApp (Load Profiles)<br>-[Link] DRP Demo Results Library |
| *Symbology* | Unique (random) |
| *Symbology Key* | Circuit Name |

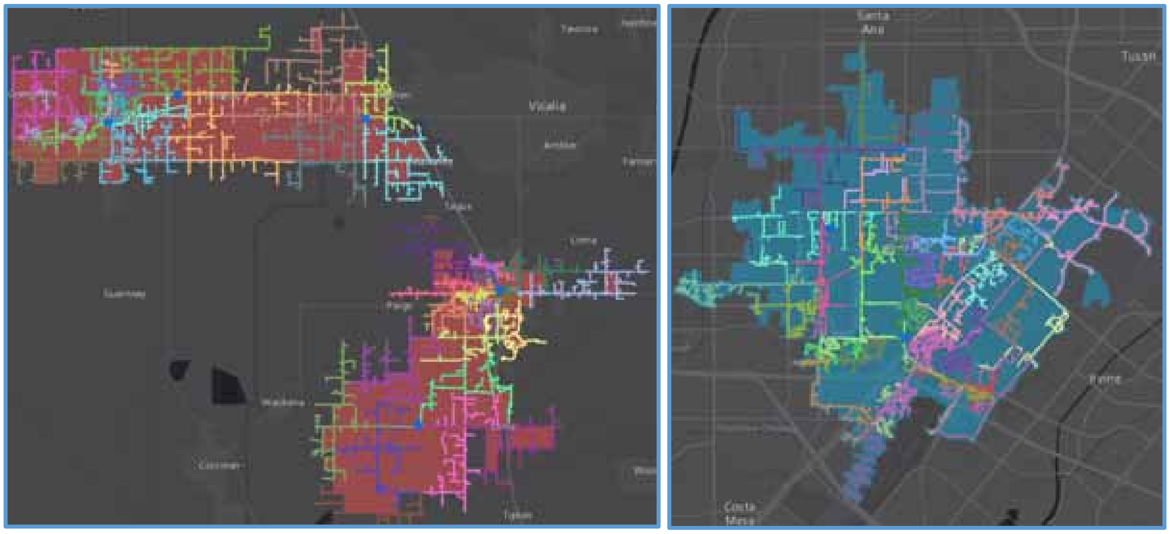


FIGURE 58: LOAD PROFILES & CUSTOMER TYPE BREAKDOWN LAYER (LEFT- RURAL, RIGHT-URBAN)


FIGURE 59: LOAD PROFILES & CUSTOMER TYPE BREAKDOWN POP-UP

## Demonstration Project A: ICA Results

| *Layer* | **Demo A - ICA Results** |
|---|---|
| *Features* | 3-phase primary conductor, node-to-node sections |
| *Attributes* | -Circuit<br>-Section ID<br>-Voltage (kV)<br>-Substation<br>-System<br>-Integration Capacity, Uniform Generation (MW)<br>-Integration Capacity, Uniform Load (MW)<br>-Integration Capacity, Typical PV System (MW)<br>-[Link] DERiM User Guide<br>-[Link] DERiM WebApp (Load Profiles)<br>-[Link] DRP Demo Results Library |
| *Symbology* | Color Gradient: red (low) to green (high) |
| *Symbology Key* | Integration Capacity, Uniform Generation (MW) |

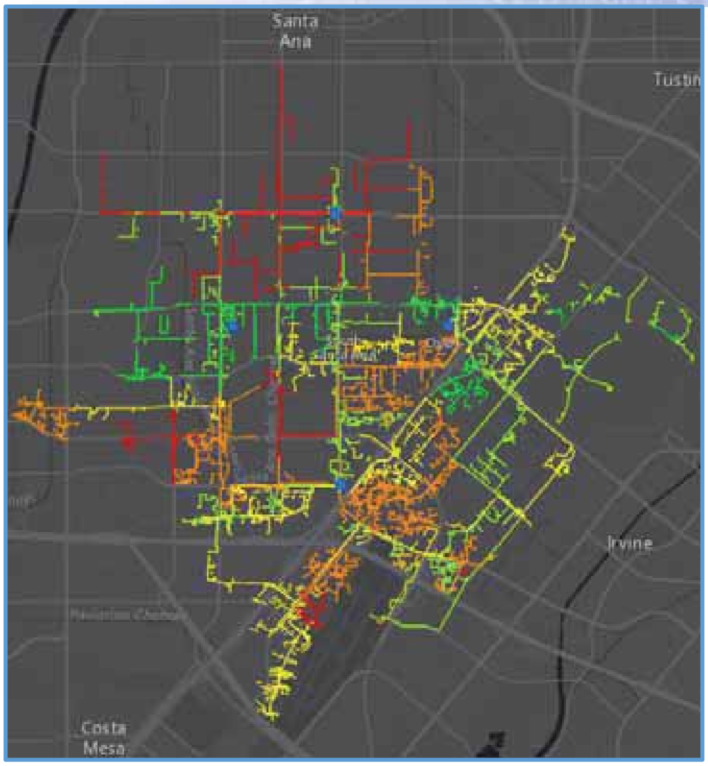



FIGURE 60: ICA RESULTS LAYER

(1 of 7)

**Demo A - ICA Results: Cobalt**

| | |
|---|---|
| Circuit | Cobalt |
| Section ID | jii4z31f_1k0j9$qha90a1jaj_1k0j9 |
| Voltage (kV) | 12.00 |
| Substation | Camden 66/12 |
| System | Johanna 220/66 System |
| Integration Capacity, Uniform Generation (MW) | 2.62 |
| Integration Capacity, Uniform Load (MW) | 0.12 |
| Integration Capacity, Typical PV System (MW) | 6.05 |
| DERiM User Guide | More info |
| DERiM WebApp (Load Profiles) | More info |
| DRP Demo Results Library | More info |

FIGURE 61: ICA RESULTS POP-UP

## Demo A: Load Profiles & Web Application

In order to meet the requirement of publishing load profiles, SCE will publish a new ArcGIS Online Web Application. The DERiM Web Application will host the load profiles for Demo A, with no other GIS data. SCE identified this to be the quickest, and simplest method to comply with the requirement using existing solutions in a limited timeframe. When users click a map feature in the DERiM web map, they will be presented with a link to load profiles in the DERiM web application. Clicking this link will take them directly to the web application. Please refer to the DERiM User Guide for step-by-step instructions to display load profiles for DPA, substation, and circuits.

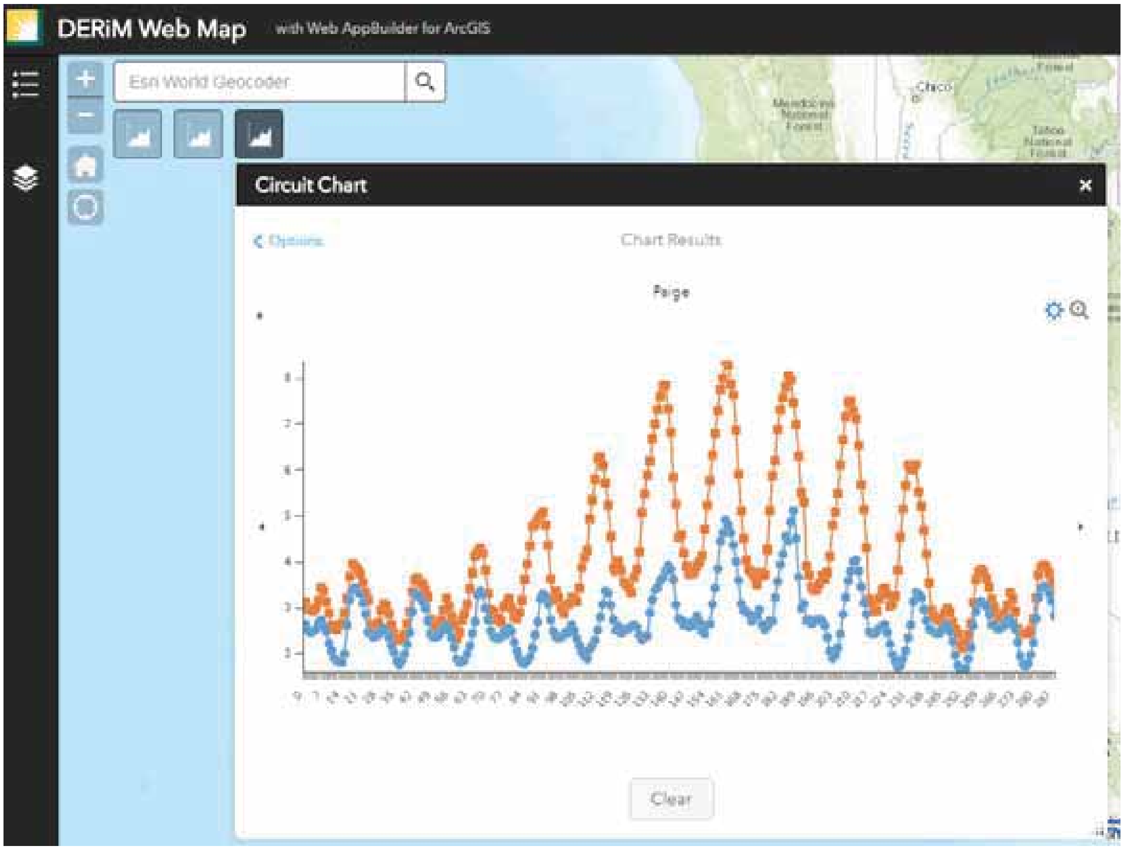



FIGURE 62: EXAMPLE OF LOAD PROFILE IN DERIM WEB APPLICATION

# 8. Additional Studies

## 8.1. Smart Inverter Functionalities

Smart inverters have functionalities that when applied properly can mitigate some of the impacts created by higher levels of DER penetration. Table 6 outlines the various phase I smart inverter functions which have been approved under Rule 21 proceeding and provides an indication of which functions would be able to influence ICA calculations. [23]

TABLE 6: SMART INVERTER PHASE I FUNCTIONALITIES

| SIWG Phase 1 Function | Description | Applicable to ICA? | Can it be evaluated in ICA? |
|---|---|---|---|
| Anti-islanding | Prevent unintentional island after loss of utility voltage | Depends on utility and already considered in standard inverter analysis | YES |
| Low/High Voltage Ride through | Maintain connection to grid through fault conditions | NO<br>Operational Requirement | N/A |
| Low/High Frequency Ride through | Maintain connection to grid through fault conditions | NO<br>Operational Requirement | N/A |
| Dynamic Volt/VAr operation | Adjust VAr output as a function of voltage at the PCC | YES | YES |
| Ramp rates | Vary the rate at which inverter changes output | NO<br>Operational Requirement | N/A |
| Fixed power factor | Operate inverter at PF other than 1 | YES | YES |
| Reconnect by soft start | Slowly ramp up output upon reconnecting to grid | NO<br>Operational Requirement | N/A |

### 8.1.1. General Approach

As part of the continuous refinements and improvements of the ICA methodology and with inputs from the ICAWG, SCE evaluated the impacts of smart inverters on Integration Capacity values at each node or line section on one distribution feeder within a DPA. The analysis included the application of the Volt/VAR function on a feeder which has its final ICA limited by the high voltage limit when using traditional inverters.

The selection criterion for the selected distribution feeder are detailed below:

- Steady state voltage was the most limiting component of the ICA.
- The selected feeder had relatively high integration capacity under the other screens such as thermal, protection, etc. This provided the opportunity to analyze if and how much the integration capacity can increase by utilizing the Volt/VAR function from the smart inverters.

[23] Smart Inverter function with phase I functions will be certified under UL 1741 and UL 1741 SA. Per SCE's Rule 21 Tariff, certified inverters with Phase I functions will be required to be installed for project interconnecting after August 2017.

To test the Volt/Var smart inverter function as described above, SCE selected the Goldenbear 12 kV circuit connected to the Mascot 66/12 kV Substation in the Rural DPA. The Goldenbear 12 kV circuit is a typical rural feeder that is longer in comparison to the system average. It has the following physical and electrical characteristics:

- The end of the main line is more than 8 miles from the source substation and has a total 3-phase conductor length of 33.5 miles
- The end of line resistance is approximately 11 Ohms as compared to the system average 1.75 Ohms
- As shown in Figure 63, the Goldenbear feeder has a light load profile throughout the year. Most distribution feeders will experience a peak load condition greater than 350 amps at times within the 12 months (typically the summer period). However, it can be observed from Figure 63 that the peak for the Goldenbear is approximately 150A which is lower than typical distribution feeders.

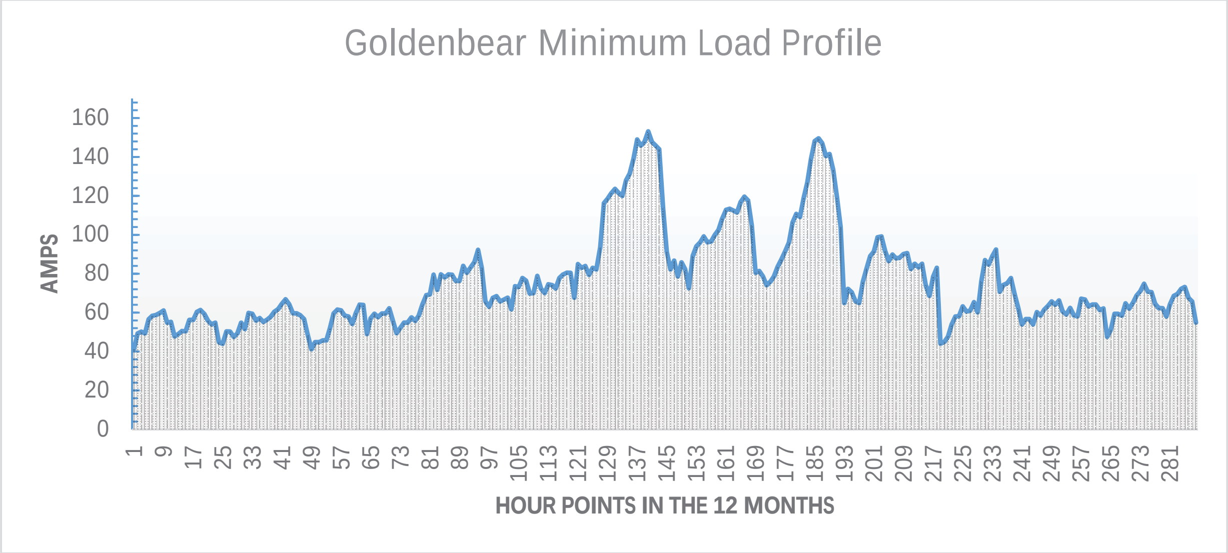



FIGURE 63 GOLDENBEAR MINIMUM LOAD PROFILE

- As shown Figure 64, the circuit has low integration capacity values under Steady-State Voltage (SSV) in comparison to thermal and protection especially as resistance increases away from the substation, which is as the distance from the substation increases.

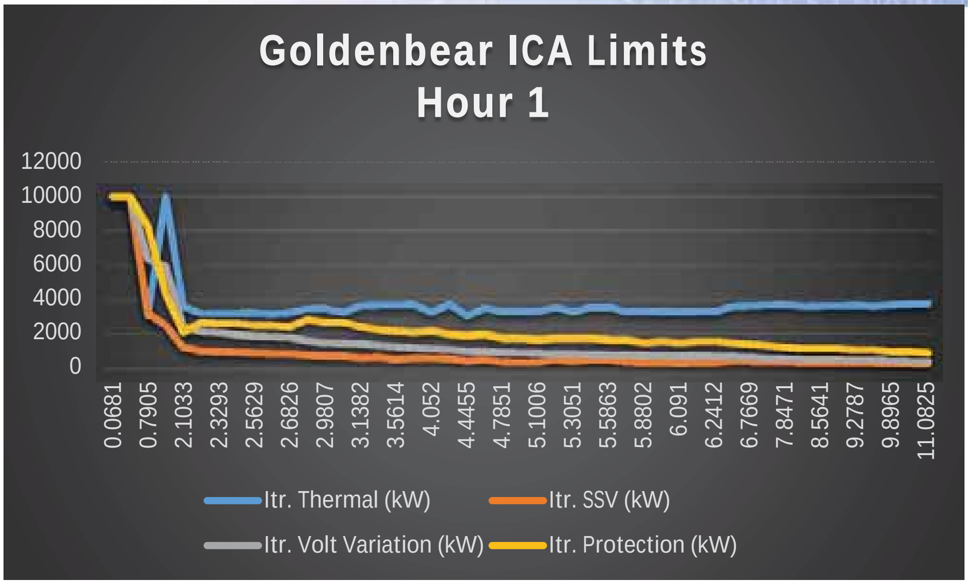



FIGURE 64 GOLDENBEAR TRADITIONAL INVERTER INTERCONNECTION CATEGORY ICA

### *Applied Study Methodology*

The applied methodology for Smart Inverters for Demo A was to test the ability of the Smart Inverter Volt/Var function to mitigate the high voltage conditions which traditional inverters create.

SCE understands that there are other study scenarios of interest. However, due to the flexibility of smart inverter functions and their potential connection to other regulatory proceedings (e.g., Demo B), it would be necessary to determine with stakeholders the set of limitations which are to be tested. SCE looks forward to continue collaboration with the ICAWG and stakeholders to determine the next level of Smart Inverter analysis.

- The Volt/VAR function was applied to every node on the Goldenbear feeder to determine the resulting integration capacity using the volt/var function
- The Volt/VAR curve utilized was based on a dead-band of 116V – 124V on a 120V base. The maximum reactive power is +/- 30% with a slope of 5% as shown is Figure 65 with a maximum reactive power absorbed from the substation at the distribution breaker to be one MVAR.

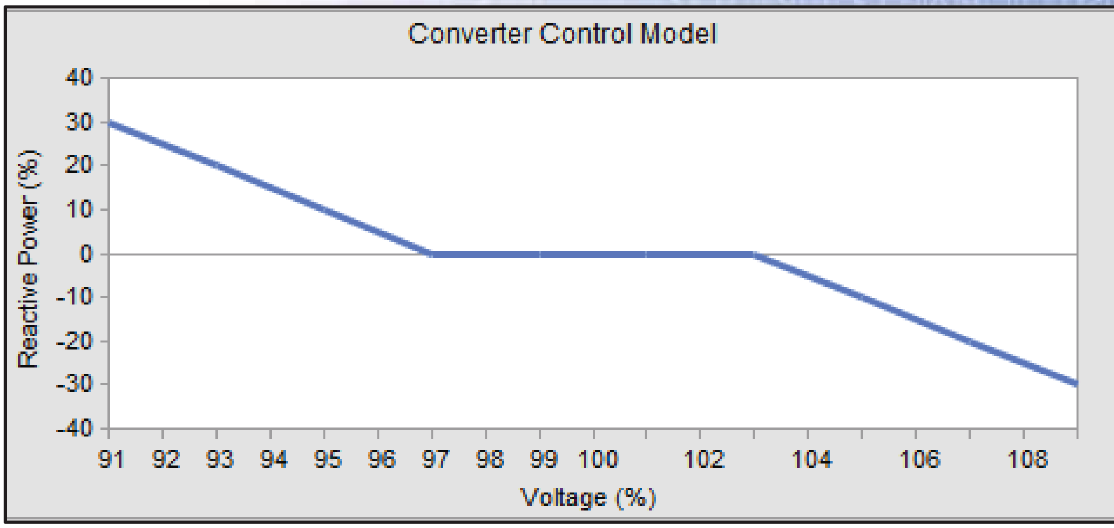



FIGURE 65: APPLIED VOLT/VAR CURVE

### 8.1.2. Results and Findings

Figure 66 shows the existing voltage profiles along the circuit. Under current load conditions with power flow from the substation to the customers, it can be observed that the voltage decreases as the distance increases from the substation. This is a typical voltage profile for feeders with power flowing from the substation to the load. The distribution system was designed to operate properly under this condition.

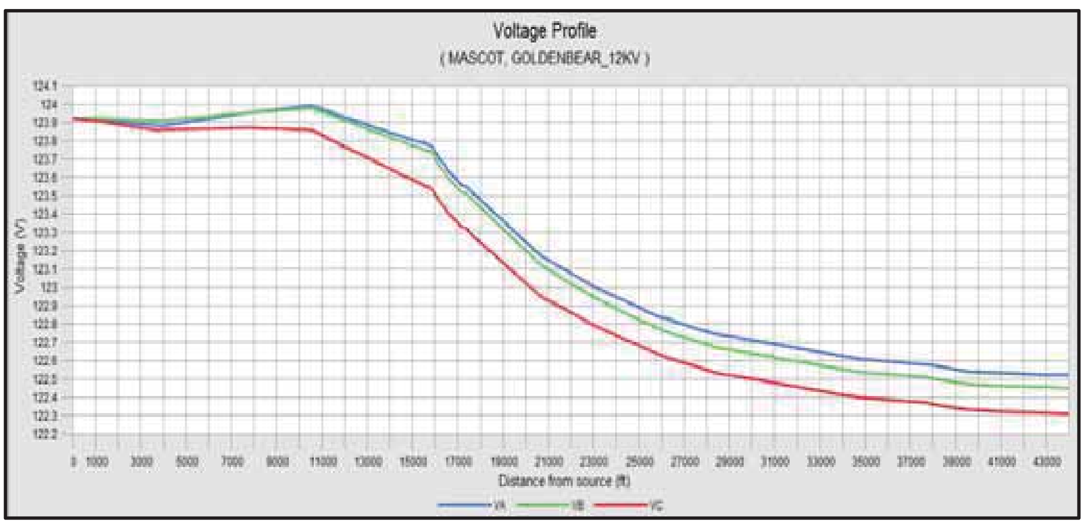



FIGURE 66 GOLDENBEAR FEEDER VOLTAGE PROFILE

When DER with traditional inverter-based technology is utilized, it can be observed from Figure 67 that voltage towards the end of the feeder increases significantly so that electrical power can flow towards the substation. The steady state ICA is limited to the point where the DER causes the feeder voltage to be at +5% of nominal voltage (e.g. 126V).

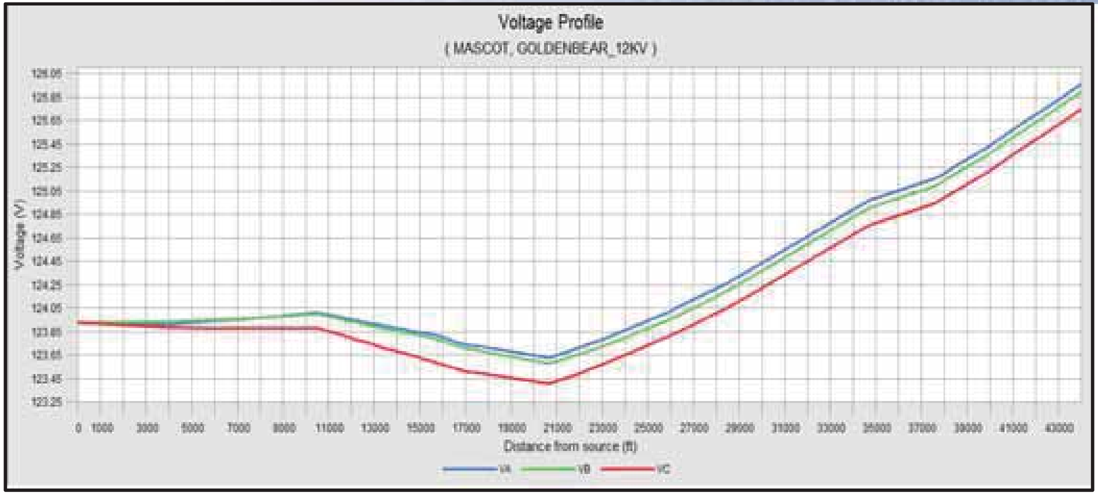



FIGURE 67 GOLDENBEAR FEEDER VOLTAGE PROFILE WITH TRADITIONAL INVERTERS

To determine the effect of the Smart Inverter Volt/Var curve to the calculated ICA, the Volt/Var curve profile as shown in Figure 65 was activated on the DER and the maximum ICA values without exceeding the Steady State Voltage was determined at each node.

Figure 68 shows the impact that the applied Volt/Var curve has on the ICA values. The following are some important observation:

- Near the substation, the volt/var function does not have significant effect to the ICA values. This is because near the substation, the system is very strong and smart inverters would have to absorb large amounts of reactive power from the substation in order to have effect on the voltage. However, for this study, SCE limited the amount of reactive power that can be absorbed from the substation to maximum of 1 MVAr, as to be able to maintain the substation as close to unity as possible.
- Impact of reactive power function in smart inverters have no significant effect of ICA when X/R is less than 1 .
- Smart inverter have the greatest positive affect to Steady State Voltage ICA at the middle of the feeder where the X/R is still higher than one. This is also where the absorbing of reactive power had most affect to steady state voltage.
- For the Goldenbear feeder, the average % increase in ICA was approximately 40% or an approximately 720KW increase on average. Depending on the node location, the increase was as high as 126% if the best location with the feeder while other locations where as low as 2%.

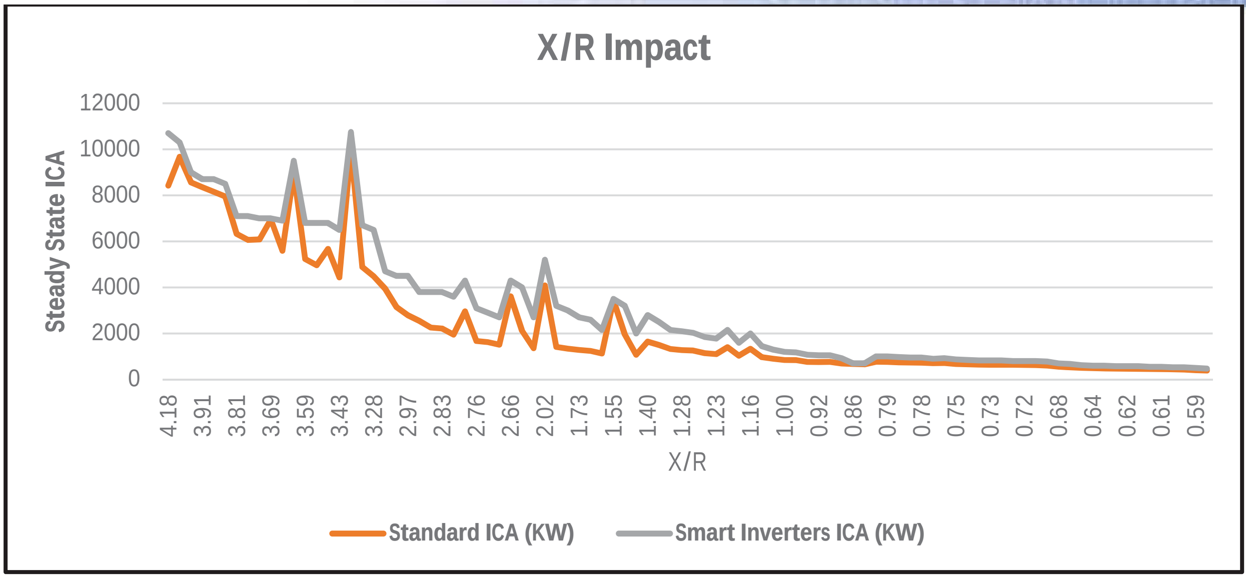



FIGURE 68 X/R IMPACT TO STEADY STATE VOLTAGE ICA

As discussed in the ICAWG, Smart Inverters are versatile and may have various application. In this study however, given the time restraint to complete the study and without significantly more discussion with stakeholders on the various application of smart inverters, SCE limited this study to specify the volt/var curve specified in Figure 65. SCE looks forward to additional discussion with ICAWG and stakeholders on future study needs.

## 8.2. DER portfolios

Demo A generates DER technology-agnostic ICA results for power-consuming DERs and power-producing DERs. ICA values for specific DER or portfolios of DER types can be developed based on the technology-agnostic ICA results. Due to the geospatial characteristics and technology variations, a typical DER operational profile and/or portfolio may not represent any customer's project design and specifications. Therefore, the ICA results based on assumed typical DER operational profiles may not provide accurate and valuable information to customers. Instead, Utilities developed an ICA translator tool to convert the technology agnostic ICA results into a set of ICA results with specific DER types or portfolios using the DER operational profiles of any design. Compared to being constrained to specific DER profiles used to generate the ICA results, this approach provides flexibility for users to utilize the technology-agnostic ICA results and develop a portfolio of DER technologies that can fit their specific need, reduce the impact to the grid, minimize the potential costs due to system upgrade, and maximize the economics of a project plan.

From the computational efficiency perspective, this approach allows for ICA to be run only once for power producing DERs and once for power consuming DERS. Given the significant amount of data being generated and the level of computing resources required to generate the ICA results, this approach can most effectively utilize Utilities resources to produce the information that is truly valuable to customers. To this extent and with ICAWG consensus, it was agreed that SCE would meet the ACR requirements by providing the following:

- Calculating and publishing "agnostic" ICA profiles for "Uniform Generation" and "Uniform Load" at each node.
    - Agnostic energy-producing DER ICA 576 values (Gen ICA).
    - Agnostic energy-consuming DER ICA 576 values (Load ICA).
- Calculation of typical fixed PV ICA (PV_ICA).
    - Typical fixed axis PV ICA 576 values (Fixed-Axis PV ICA).
- Develop and make available an ICA translator.

SCE will make available an "ICA translator tool which interested parties may use to convert the agnostic ICA values to a technology specific ICA value". Figure 69 depicts the ICA translator which can be downloaded at: http://on.sce.com/drpdemos

**Southern California Edison ICA Translator V1.0**

*Instructions: Enter hourly Load Agnostic 576 Hourly ICA results in the left table to update the expected Load ICA limit based on the DER Profile category.*

*SCE does not guarantee the accuracy of the data. The data is intended for information only and the user is responsible for the accuracy and use of the data. SCE maintains ownership of this tool and can make changes at any time.*

Technology specific ICA was limited to 4 times the average agnostic ICA. This was done to limit the technology ICA values to within technical reason. Not doing so would result in unrealistic technology specific ICA values at times when technology specific is very low or was zero for that hour. When techlogy specific output was zero for that hour, the techology ICA was set 4 times the average agnostic ICA.

USER SPECIFC ICA CALCULATION

| Enter Agonostic Houly ICA Value | | | Universal Gen (Inverter) | | PV | | PV w/ Storage | | PV w/Tracker | | ENTER User Specified Gen Profile | User Specified Gen ICA Profile | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hour | Min | Max | Min | Max | Min | Max | Min | Max | Min | Max | Profile | Min | Max |
| 1 | 3.136 | 3.136 | 3.1 | 3.1 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 0.033333333 | 11.5 | 11.5 |
| 2 | 3.134 | 3.134 | 3.1 | 3.1 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 0.033333333 | 11.5 | 11.5 |
| 3 | 3.134 | 3.134 | 3.1 | 3.1 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 0.033333333 | 11.5 | 11.5 |
| 4 | 3.121 | 3.121 | 3.1 | 3.1 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 0.033333333 | 11.5 | 11.5 |
| 5 | 3.111 | 3.111 | 3.1 | 3.1 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 0.033333333 | 11.5 | 11.5 |
| 6 | 3.111 | 3.111 | 3.1 | 3.1 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 0.033333333 | 11.5 | 11.5 |
| 7 | 3.111 | 3.111 | 3.1 | 3.1 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 0.033333333 | 11.5 | 11.5 |
| 8 | 3.111 | 3.111 | 3.1 | 3.1 | 11.5 | 11.5 | 11.5 | 11.5 | 9.3 | 9.3 | 0.335 | 9.3 | 9.3 |
| 9 | 3.107 | 3.107 | 3.1 | 3.1 | 9.3 | 9.3 | 11.5 | 11.5 | 4.6 | 4.6 | 0.673333333 | 4.6 | 4.6 |
| 10 | 3.107 | 3.107 | 3.1 | 3.1 | 6.3 | 6.3 | 11.5 | 11.5 | 4.0 | 4.0 | 0.773333333 | 4.0 | 4.0 |
| 11 | 3.107 | 3.107 | 3.1 | 3.1 | 5.2 | 5.2 | 11.1 | 11.1 | 3.8 | 3.8 | 0.820833333 | 3.8 | 3.8 |
| 12 | 3.107 | 3.107 | 3.1 | 3.1 | 4.6 | 4.6 | 8.2 | 8.2 | 3.8 | 3.8 | 0.820833333 | 3.8 | 3.8 |
| 13 | 3.101 | 3.101 | 3.1 | 3.1 | 4.6 | 4.6 | 7.2 | 7.2 | 3.8 | 3.8 | 0.820833333 | 3.8 | 3.8 |

FIGURE 69: SCE PROVIDED ICA TRANSLATOR

Fundamentally, the ICA takes the agnostic ICA at each hour and divides it by the per-unit production of the specific technology or portfolio of technologies. For example, if the ICA value at a particular hour is 2MW and the technology specific output per 1MW of installed capacity is 0.5MW, then the ICA for such technology would be 2MW/0.5 or 4MW. Thus is essence the ICA calculator deploys the following equation:

$$TS_{ICA}(t)=TA_{ICA}(t)/TSpu(t) \text{ for } t = 1 \text{ to } 288 \text{ hour}$$

Where: $TS_{ICA}(t)$=Technology Specific ICA at that hour

$TA_{ICA}(t)$= Technology Agnostic ICA at that hour

$TSpu(t)$ = Technology Specific per unit production

t = hours of translation from 1 hour to 288 hours

There are cases where the technology specific p.u output is very low or zero, the division in these cases yields a very large number or infinite number (example 1.0MW/0.00001 =

100,000MW or 1.0MW/0= infinite) which is not realistic. For these cases, the ICA translator limits the ICA value to 4 times the average of the agnostic ICA value to provide a number which is high but not unrealistic. Figure 70 shows a figurative sample of the ICA translator.

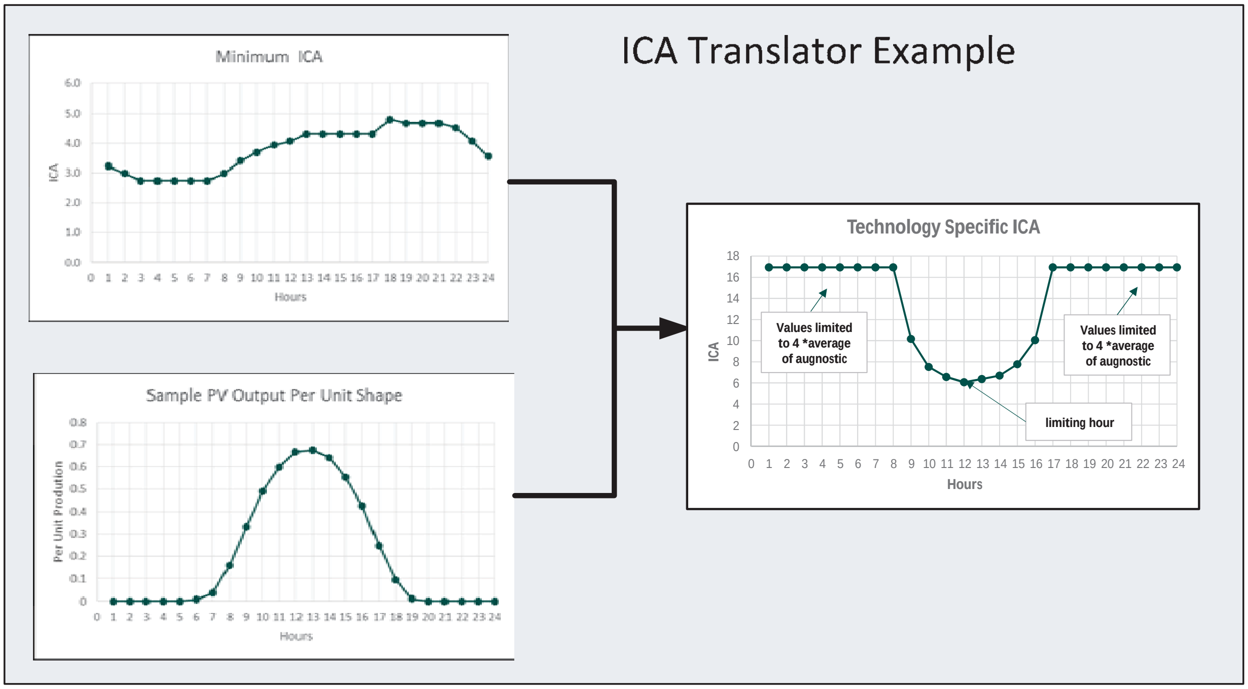



FIGURE 70: FIGURATIVE EXAMPLE OF ICA TRANSLATOR

## 8.3. Transmission Penetration

At high levels of DER penetration, it is necessary to adequately study the transmission system for reliability impacts caused by high levels of DER on the distribution system. These impacts include but are not limited to frequency response, voltage control and system protection. Most of the impacts to the transmission system will become more evident when power flows from the distribution system to the transmission system (reverse power flow at the substation busbar). Furthermore, excessive levels of DER may result in exceeding the thermal limits of the substation transformers, bus, and conductors. Figure 71 shows a condition where reverse power flow at a substation will occur if maximum ICA is installed on multiple distribution feeders.

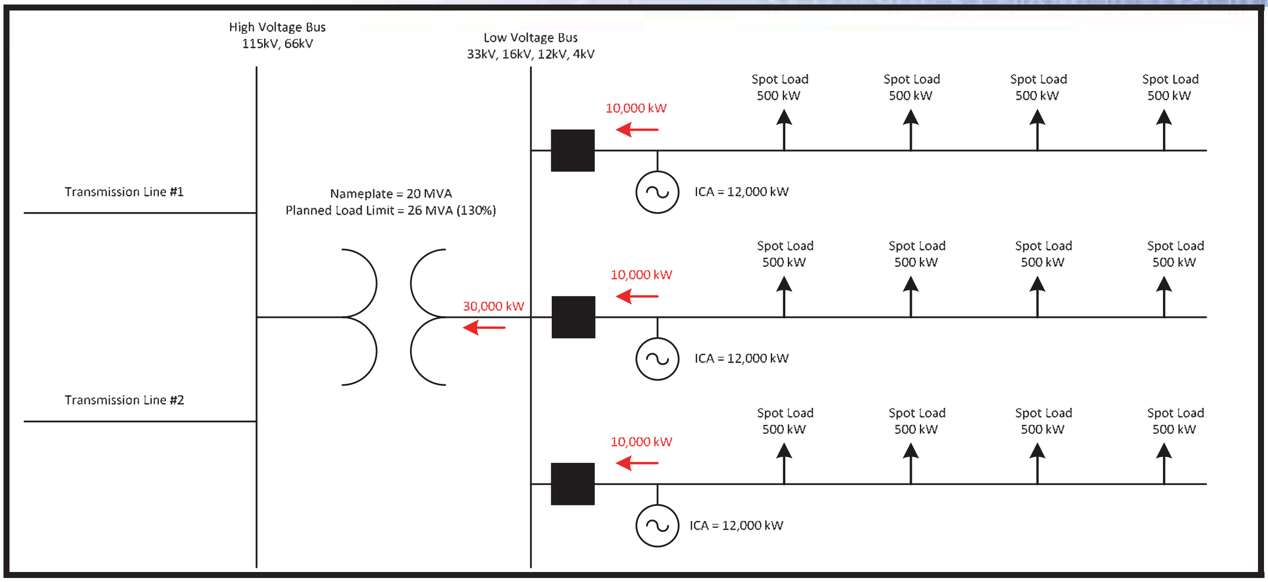



FIGURE 71: SUBSTATION REVERSE FLOW

As part of Demo A, SCE conducted reverse flow analysis to determine the maximum allowable ICA at the substation level under the reverse allowed scenario while the more detailed transmission levels analysis would be part of future enhancements to ICA based on input from the ICAWG. The substation ICA was established such that the aggregate ICA for all feeders at a substation shall not exceed the summation of the load on all feeders plus the substation thermal capacity:

$$Substation\ ICA\ (kW) = Substation\ Capacity\ (kW) + Substation\ Load$$

Figure 69 shown a CYME substation simulation showing power flow from the transmission to distribution system where the substation transformers are loaded to 43.4% of their thermal capacity. However, as shown in Figure 72, when the maximum ICA is installed at each of the distribution feeders, the power flow changes direction toward the transmission system and causes the substation transformer to become loaded to 123.5% of its thermal capacity. Therefore, the ICA at each of the feeders should be limited by the substation transformer capacity limitations. While the limitation of substation transformer capacity was not included in SCE's ICA calculations, other substation limitations such as breaker thermal and interrupting ratings was included in the ICA calculations as described in section 4.4.9.

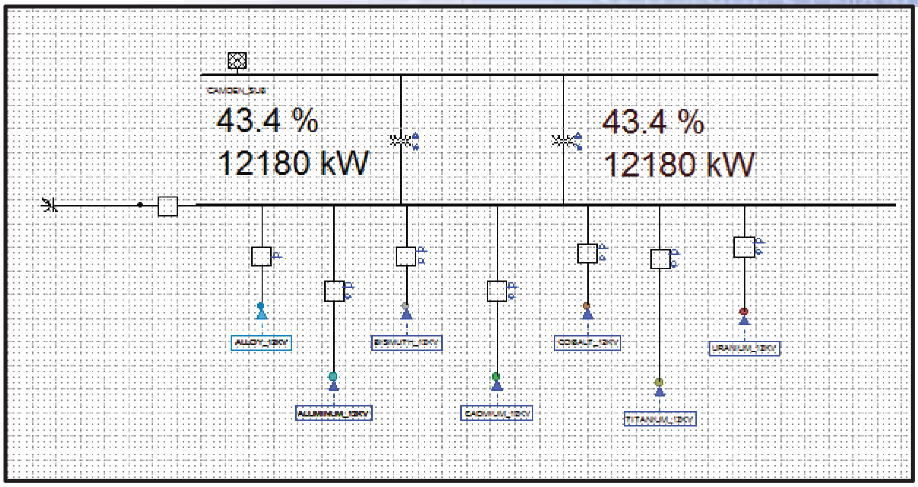



FIGURE 72: CYMEDIST SIMULATION OF FORWARD POWER FLOW

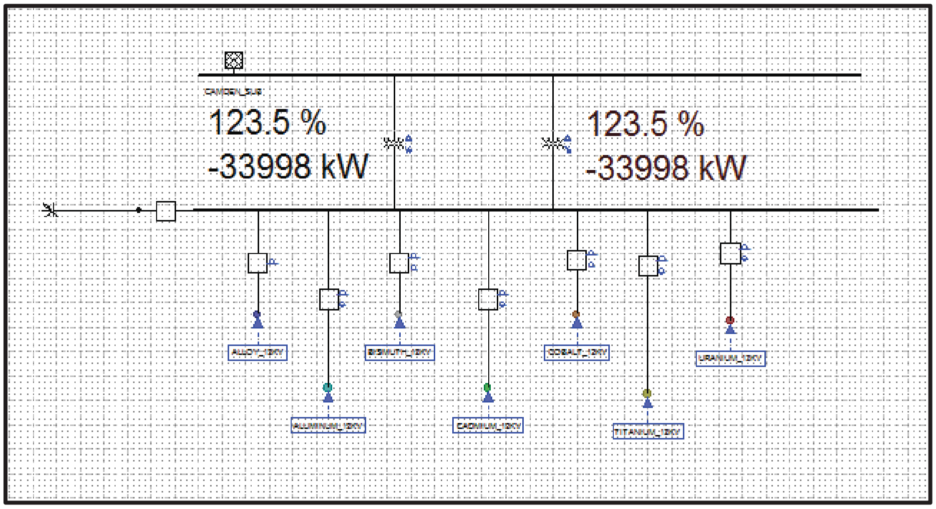



FIGURE 73: CYMEDIST SIMULATION OF REVERSE FLOW TO TRANSMISSION

In the future, and as part of ICA enhancement, SCE plans to conduct further analysis to determine the impact of high DER penetration on voltage stability, frequency response, and system protection on the bulk system.

# 9. Demo A Learnings

SCE, alongside the other IOUs, obtained lessons learned from the multiple techniques explored as part of the Integration Capacity Analysis (ICA). These learnings are outlined within this section. Discussion will first summarize the learnings and then provide details on the topics discussed. The following is a list of specific objectives within Demo A and learnings around those objectives.

1) Reverse Flow Limitation
   - The IOUs implemented a consistent criterion for Operational Flexibility (OpFlex ICA) in which strategic devices across the distribution system, such as SCADA operated switch points and voltage regulators, limited the amount of generation for all downstream nodes to the load downstream of the strategic device, as outlined in section 4.4.8. While removing the OpFlex ICA limitation category would significantly increase the Integration Capacity, higher levels of DER on the distribution system could create significant issues to reliability, safety, and/or power quality. Additional exploration of different methodologies is required to determine how this limitation may further be modified to allow higher levels of ICA without compromising safety, reliability, or power quality. SCE proposes to maintain this limitation due to the low level of visibility and control of DERs. At such time when SCE has adequate visibility of the resources and sufficient control, this limitation may no longer be applicable.
2) DER Growth and Forecast
   - Currently, SCE does not have a scalable methodology to determine how forecasted DER levels will be distributed throughout nodes within each distribution feeder. To this extent, SCE distributed the DER forecast evenly based on connected KVA on the distribution feeder. SCE understands this method of disaggregating future DER is not optimum but without knowing which customers will adopt DER and when they will adopt DER, it is not possible to more accurately disaggregate feeder level forecasts to nodal level forecasts. Figure 74 shows an example of how SCE desegregated the feeder DER forecast to node level DER forecast.

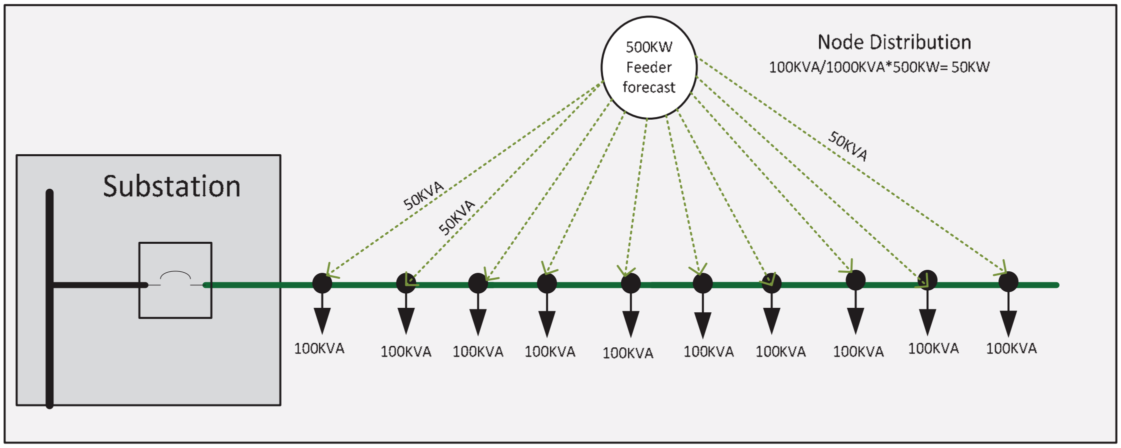



FIGURE 74: DER DISAGGREGATION METHODOLOGY TO NODE LEVEL

3) Diverse Locations for Demo

Selecting two DPAs that are diverse created learning opportunities:

- Preparation of network models was significantly more difficult for feeders on the Rural area than feeders on the Urban area, as rural feeders are typically much longer than urban feeders.
- Network power flow solutions took significantly longer for rural feeders than urban feeders, again due to the fact that rural feeders are typically much longer than urban feeders.
- Power solutions for substation level simulations were more successful in the urban area than substations on the rural area due to higher system complexity of the rural substation.
- Significant work was required to properly prepare the CYME network models, including phasing and load balancing.

4) DER Portfolios and New Technology

- The utilization of an “ICA translator” in combination with the agnostic ICA calculation reduced the level of work required for determining, preparing and publishing the ICA based on technology or DER portfolios.

5) Maps and Outputs

The work SCE performed for the Distribution Resource Plan Demonstration Projects A[24] resulted in a number of factors that should be considered for future requests to map large volumes of data:

- SCE does not currently employ a user-friendly web-based platform for sharing interactive non-geospatial (non-mapped) data, such as the load profiles in the DERiM WebApp. Since the load profiles are not geospatial in nature, a superior solution would be to utilize a web-based data viewer that provides a more robust, interactive experience. Due to the accelerated timeline, SCE’s approach to the Demonstration Project maps was to leverage existing solutions that could be developed in a very short timeframe. Therefore, SCE leveraged the readily available Web Application templates as part of ESRI’s ArcGIS Online platform. As a result, SCE was unable to implement tabbed map browsing, with interactive charts and custom graphs. These custom map elements will require additional investments in hardware and software infrastructure.
- The requirement to publish node-to-node line sections presented an exponentially larger set of data than was previously published for the initial DRP filing. This increase in data required the team to look for creative ways to prevent an excessive draw on the ArcGIS Online cloud server, which otherwise results in a “layer did not draw completely” error. This error causes the features (line sections) to begin to draw, but then stop abruptly, leaving holes in the visible dataset. There are a variety of ways to work around this, of which SCE enabled scale dependencies. Scale dependencies prevent the data from loading until the map zoom level is close

[24] Equivalent comments and learning related to DRP demonstration B

enough to limit the number of features to an acceptable level. With some additional support directly from ESRI, SCE was able to maintain the "Metropolitan Area" zoom level, consistent with existing DERiM ICA data (four sections per circuit). In the case of Demo B LNBA results, the projects were not unique on a section-to-section basis, so SCE elected to publish the concatenated circuits instead of the individual line sections. This enabled the ability to load the entire DPA in a single view, without having to zoom in. SCE expect the volume of data to continue to increase in the near future, and therefore emphasizes the need to invest in and deploy more robust hardware and software infrastructure that is capable of supporting the growing need. SCE met the requirement to publish a large volume of downloadable data files using a two-pronged approach: creating a dedicated webpage on the Azure Cloud Platform, and publishing all geospatial data to ESRI's OpenData website (please refer to the DERiM User Guide for a step-by step guide on downloading data from OpenData). The capability to publically share such a large dataset would require IT investments to build a scalable solution independent from sce.com. SCE was concerned about increased draw on the sce.com server that could potentially impact Customers' ability to perform core business transactions (view/pay bills, etc.).

- For full implementation of ICA for all of SCE's distribution circuits, SCE believes only the most actionable data which can be used in the interconnection process should be included in its DERiM such as uniform generation and fixed PV ICA values. In addition, the ICA results for only 82 circuits resulted in almost 7 GB of downloadable data. Extending this file size per circuit to all of SCE's distribution circuits would produce nearly 400 GB of data. SCE does not believe this volume of data can be efficiently managed and accurately updated on a monthly basis to be consistent with current data sharing practices. In addition, SCE does not envision all of this data to be truly useful for DER developers.

6) Comparative Analysis

- IOUs gained much consistency on baselining against a reference model, such as the IEEE-123 Test Feeder. However while the IEEE 123 Test Feeder was useful for initial alignment, a more representative California feeder is desired for continued comparison and validation.
- Running many hours of power flows can lead to simulations that do not converge to solutions. The risk of this increases with the Iterative Method given the additional amount of power flow simulations required by that method.
- Currently, the Streamlined Method is faster than the Iterative Method, but is not as good at determining issues for more complex feeders. It may provide false positives due to lack of exact simulation.
- The Iterative Method is more accurate in determining power flow conditions than Streamlined Method.

7) Locational Load Shapes

- Using smart meter data helps provide more granular data points to allow for more confidence in the load allocation, especially across different hours. However, since power flow simulation is an optimization algorithm, the extra constraining data points may add to issues with specific scenarios not converging within power flow tools.

## 9.1. Computational Efficiency

In consensus with ICAWG, the IOUs were allowed to apply three computational efficiency methods to increase the speed at which ICA values could be developed without materially affecting the ICA values. In Demo A, SCE applied two of the three computation efficiency methodologies.

- SCE utilized the load profile reduction technique which saved approximately 5 hours per feeder by deriving approximately 90% of the ICA values for calculated ICA values which exhibited the equivalent loading characteristics
- SCE utilized the “reduction categories” reduction technique and saved approximately 9 hours of computational time for both DPAs
- SCE did not utilize the reduction-of-nodes technique in its Demo A due to the Demo A timeframe and required methodology implementation time. SCE believes this technique will be used for future ICA processes once the methodologies are implemented and tested for accuracy

### 9.1.1. Profile Reduction

Currently, Demo A requires analysis of a 576 load profile. A 576 load profile is composed of hourly load profiles for typical maximum and minimum loading days for every month for 12 months. The purpose of analyzing 576 hours is to study different loading levels in order to have a comprehensive understanding of the integration capacity range.

The DER integration capacity is a function of the feeder physical characteristics, voltage, and loading. The feeder physical characteristics remain constant from hour to hour. The feeder voltage is directly impacted by the feeder loading level. Therefore, the integration capacity varies if and only if a significant shift in load (or voltage) occurs. Even though these 576 hours are considered as representative hours of the entire year (i.e., 8760 hours), many of these hours have similar loading conditions which produce equivalent integration capacity results. Depending on the circuit characteristics, SCE has estimated that approximately 78% to 91% of hours can be reduced in the analysis while maintaining the ability to closely represent the 576-hour ICA profile as required by the ACR.

As the 576 hours represent both maximum and minimum loading days throughout the year, there are 288 hours represented for each of the two loading conditions. Figure 75 and Figure 76 show a pair of load profiles based on a 288 loading profile and the reduced 56-hour values, respectively. The 56-hour load profile achieves an 80% reduction, but maintains a very close approximation to the full range load profile with a slightly less degree of smoothness in the profiles. Both profiles cover the full loading range from 130Amps to 310Amps, which ensures the full range of integration capacities to be captured at this location.

IOUs believe that performing profile reduction using industry accepted data reduction methods can significantly improve the ICA runtime performance while still providing the required level of ICA accuracy. SCE implemented a load profile sweep to reduce the computational time required to return the ICA values with a 576 loading profile as input. This load profile sweep progressively analyzed the load profile starting at hour 0. Each value condition was then reviewed to determine if a loading condition between a pre-defined bandwidth was analyzed (±6 amps). If there was a value within that range, the loading condition inherited the ICA results of the value within the bandwidth. For example, if hour 200's loading was 300 Amps, and hour 20's was 301 Amps, hour 200 would inherit hour 20's ICA results.

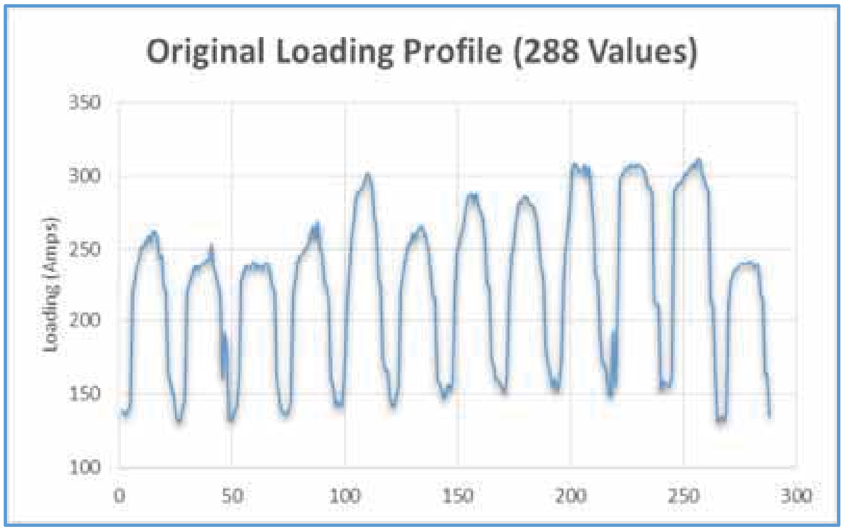



FIGURE 75: ORIGINAL 288-HOUR LOAD PROFILE


FIGURE 76: REDUCED 56-HOUR LOAD PROFILE

### 9.1.2. Node Reduction

The ICA performed as part of Demo A is a nodal analysis. This level of granularity allows the DER integration capacity to be evaluated at all locations on a circuit, but unnecessarily increases the number of iterations required. Due to the nature of circuit models, there are nodes within close proximity, with very short line sections and no customer loads in between, or nodes that are for simulation purposes only. In some cases, these nodes have the same level of impedance and loading conditions. In other words, they are electrically similar, or even identical, and analysis at these nodes will result in equivalent levels of DER integration capacity. Performing ICA on every one of these nodes will not provide additional value. Figure 77 shows that the resistance between two adjacent nodes is similar and that performing ICA calculation at these nodes does not provide different ICA results (the top pair of dialog boxes) and the loading between two adjacent nodes are also similar and does not provide different ICA results (the bottom pair of dialog boxes).

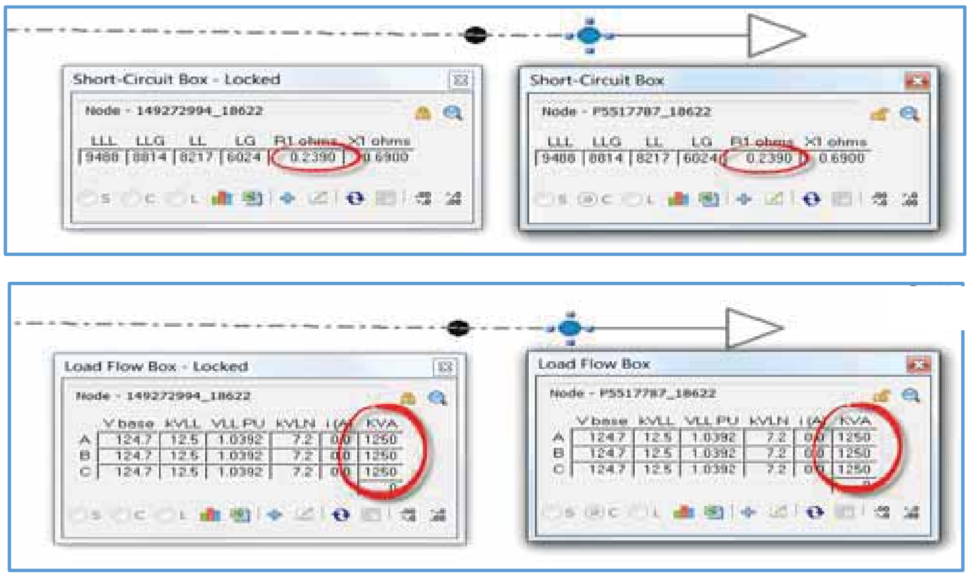



FIGURE 77 ELECTRICAL PARAMETER COMPARISON OF ADJACENT NODES

The network reduction technique maintains the primary geographical and electrical characteristics of a given feeder. It can improve the ICA computational efficiency while maintaining the resolution of the ICA accuracy. As indicated earlier, SCE did not apply this technique in its Demo A due to time constraints to develop the necessary protocols, but SCE believes that this will be an important method of implementing ICA on future projects.

### 9.1.3. Reduction of Limitation Categories

The DER integration capacity of a given node is evaluated against thermal, steady state voltage, voltage fluctuation, protection and operational flexibility limitations independently and the most limiting values are used to establish the final integration capacity limit for the node. However, certain ICA limitation categories will not be limiting factors due to the nature of some distribution feeders. For example, distribution feeders with large amount of available fault duty will not see their protection schemes compromised by the addition of DERs.

Among the five limitation categories evaluated in Demo A ICA, the voltage fluctuation and protection limitation categories are dependent on the electrical strength of the system (i.e., level of short circuit current) rather than the loading or voltage conditions of the feeder. When the End-Of-Line current of a feeder is sufficiently large (typically greater than 4,000 Amps), these two limitation categories will not affect the final integration capacity value of any node in the feeder. As a result, these two limitation categories do not have to be evaluated when the feeder is strong as these do not limit the ICA values when used. When this computation reduction technique is used, SCE will show 20 MW of integration capacity to complete the dataset such that these limitations will not affect the overall ICA results at any node. This can also improve the computational efficiency of the ICA process without sacrificing the result accuracy, which may lead to significant resource savings for the full system ICA process with a regular update bases.

## 9.2. Consistency between Methods

Performing ICA calculations with two method allowed SCE to evaluate different methods of integration capacity analysis. In general, the consistency between the two methods is as follows:

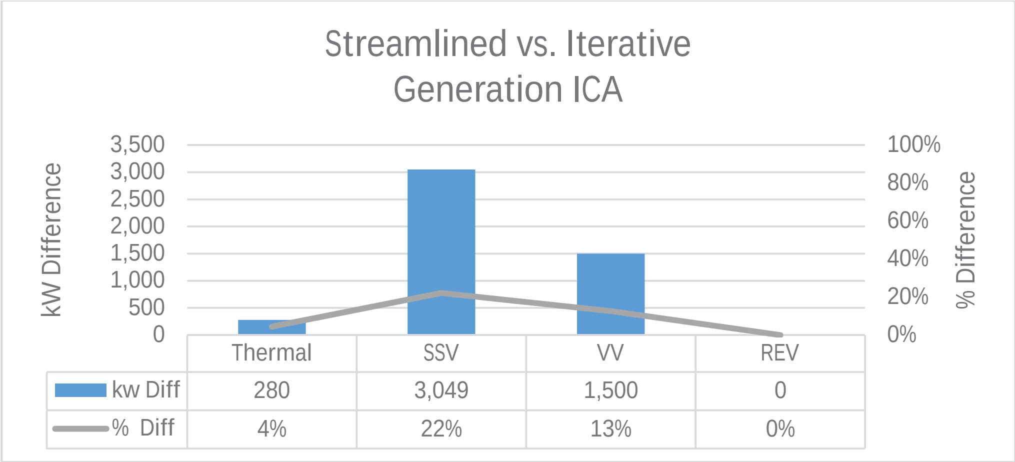



FIGURE 78 STREAMLINED VS ITERATIVE COMPARISON FOR GEN ICA

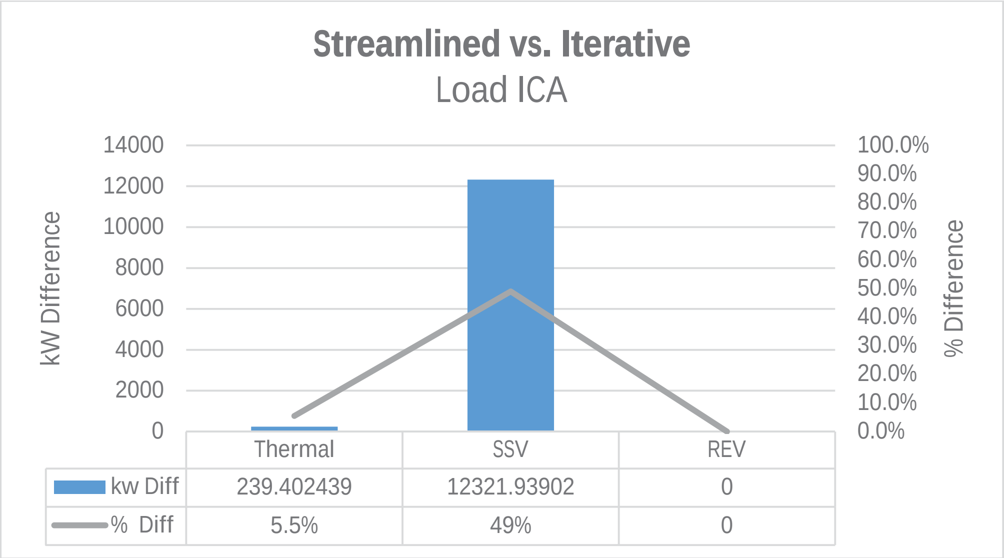



FIGURE 79 STREAMLINED VS ITERATIVE COMPARISON FOR LOAD ICA

### *Thermal Limit consistency*

In general, the Iterative Method provided a slightly higher level of ICA consistent throughout the nodes within the feeders. The % difference between Streamlined and Iterative Methods is 4 % on average which results in a 280kW difference.

### *Steady State Voltage consistency*

The % differences between approaches had a much broader range than others since the ICA values correlated closer toward the end of the feeders. Overall, the Iterative Method provided a slightly higher level of ICA on a nodal basis. The % difference between Streamlined and Iterative Methods 22% on average which results in a 3,049 Kw difference.

### *Protection consistency*

Protection is an area where significant differences were found. This was expected as the Streamlined Method utilizes a heuristic method of simply using 10% of short circuit at the node to predict the level of DER which can be installed without desensitizing the relays (reduce relay reach) while the Iterative Method used the CYME fault flow and Python scripts to determine via fault flow, the level of DER which reduces desensitized the relay to below typical standards reduced the relay reach to below 2.3* multiple)

### *Voltage Flicker consistency*

In general, the Iterative Method provided a slightly higher level of ICA. In general, the ICA values correlated closer toward the end of the feeders. The % difference between Streamlined and Iterative Methods is 13% on average which results in a 1,500 kW difference.

### *Operation Flexibility consistency*

Because the way this limit was applied, both the Streamlined and Iterative Methods yielded the same values. To determine this value for both methods, first a power flow is performed via CYME power flow tool. For the Iterative Method, this initial power flow provides indication of the power flow at each of the SCADA/VR devices and based on the power flow, the script returns the value of DER which would equal to the power flow. For example, if the power flow shows that at particular SCADA device the load was 3MW, then 3MW would be the limit as installing more than 3MW would cause a reverse of power flow at the SCADA device exceeding the limit under this criterion. Similarly, for the Streamlined Method, an initial power flow is performed using CYME power flow tool and the same data is extracted to insert in the streamlined equation which yield the same value.

## 9.3. ORA 12 Success Criteria

Office of Ratepayer Advocates (ORA) proposed 12 success metrics in the November 10, 2015 ICA workshop to evaluate ICA tools, methodologies, and results. These metrics are:

1. Accurate and meaningful results.
   a. Meaningful scenarios.
   b. Reasonable technology assumptions.
   c. Accurate inputs (i.e. load and DER profiles).
   d. Reasonable tests (i.e. voltage flicker).
   e. Reasonable test criteria (i.e. 3% flicker allowed).

f. Tests and analysis performed consistently using proven tools, or vetted methodology.
g. Meaningful result metrics provided in useful formats.

2. Transparent methodology.
3. Uniform process that is consistently applied.
4. Complete coverage of service territory.
5. Useful formats for results.
6. Consistent with industry, state, and federal standards.
7. Accommodates portfolios of DER on one feeder.
8. Reasonable resolution (a) spatial, (b) temporal.
9. Easy to update based on improved and approved changes in methodology.
10. Easy to update based on changes in inputs (loads, DER portfolio, DER penetration, circuit changes, assumptions, etc.).
11. Consistent methodologies across large IOUs.
12. Methodology accommodates variations in local distribution system, such that case by case or distribution planning area (DPA) specific modifications are not needed.

SCE, consistent with the other IOUs, incorporated these 12 recommended success metrics in the Demo A implementation. The following list describes how Demo A meets or exceeds each of these metrics, and where areas of improvement may be possible.

### *Accurate and meaningful results*

a) **Meaningful scenarios**

Demo A conducted ICA studies under two power flow scenarios to understand the DER capacity while maintaining safety, reliability and operational flexibility. One scenario explored the capability of the distribution system to integrate DER taking into account an operational limitation to not allow reverse power flow at the substation bus bar towards the transmission system. The second scenario explore the technical maximum DER capacity irrespective of power flow toward the transmission system. Furthermore, the Integration Capacity values for inverter-based uniform generation and uniform load are produced in Demo A. Finally, with the provided ICA translator, stakeholders can develop customized Integration Capacities for any DER types or DER portfolios.

b) **Reasonable technology assumptions**

ICA methodologies and assumptions have been developed based on engineering principles and practices which are commonly applied and used in the engineering industry. These assumptions include the utilization of power flow to determine limiting factors such as thermal and voltage limits, the utilization of American National Standard (ANSI) C84.1 - 2011 Range A as guiding principle for voltage fluctuation limits, the assumption on short circuit duty contribution for DER and the utilization of tariffs and standards including Rule 21 and IEEE1741/UL1547.

One area where SCE sees the need for continued improvement includes: adequate modeling of smart inverters; advances in operational flexibility limitations; and advances in reactive power group control mechanisms.

c) Accurate inputs (i.e. load and DER profiles)
SCE, in conjunction with the other IOUs, developed and validated circuit models based on the most up-to-date system configuration at the commencement of the study and leveraged load forecasting tool/algorithm, SCADA data and DER forecasts provided in the DRP filings to develop a forecasted hourly feeder load profile, which was in most cases further allocated to different customers based on AMI data. All these efforts aim to ensure the most accurate inputs are provided to the ICA methodologies for accurate ICA results.

SCE believes that the DRP OIR Track 3 efforts underway will help to improve the DER forecasts that go into the circuit model, which should improve the accuracy of the circuit load forecast. SCE expects that these improved forecasts will be incorporated into future updates to the ICA.

d) Reasonable tests (i.e. voltage flicker)
SCE applied the necessary test to calculate ICA values to show compliance with the test criteria explained in section 4.4, above. For voltage fluctuations/flicker, under the Iterative Method, SCE simulated the injection of DER until a voltage deviation of 3% from a node voltage was observed. For the Streamlined Method, a calculated 3% deviation from the steady state voltage was translated into DER capacity via the streamlined equations. For steady state voltage under the Iterative Method, DER was increased at a node until the steady state voltage was outside the criteria. For the Streamlined Method, the difference in voltage between simulation and criteria was translated to a DER limit via the streamlined equation. For thermal ratings, SCE limited DER to a value where all devices would be at maximum 100% of their thermal ratings per SCE's and typical distribution standards

e) Reasonable test criteria (i.e. 3% flicker allowed)
The power system criteria adopted in Demo A is consistent with industry standard criteria (e.g., thermal criterion), electric service rules (e.g., steady state voltage criterion), and IEEE recommended practices (e.g., voltage fluctuation criterion). For voltage flicker/fluctuation, SCE utilized the requirements under IEEE519 which limits voltage deviation to 3%. For steady state voltage, SCE utilized the limits within SCE's Rule 2 and ANSI Range A, which limits feeder voltage to +/- 5% of nominal voltage. For thermal ratings, SCE utilized SCE's thermal limits which are based on manufacturer's data and system configuration.

f) Tests and analysis performed consistently using proven tools, or vetted methodology
Industry standard power flow tools (CYMDIST) were used in the Demo A to evaluate the system conditions under various DER interconnection levels. The ICA methodologies are also synchronized amongst the IOUs based on the comparative assessment efforts to ensure a consistent ICA process.

g) Meaningful result metrics provided in useful formats
The ICA results are provided in both online map and downloadable data formats. The most practical and relevant scenario is displayed on the map while the complete data

set (i.e. 576 ICA for each main criteria) is provided in the downloadable files so that DER developers can query and retrieve relevant information. Both the online map and downloadable data are provided in sufficient details and in consistent formats so that stakeholders can easily understand and utilize the information.

Once the ICA results are put to use, there may be improvements made to the output files based on input from stakeholders. To the extent that improvements are practical, SCE will continue to strive to provide the most effective output possible.

*Transparent methodology*

The details of the methodologies (equations, assumptions and thresholds) are provided in the project reports. SCE intends to coordinate with the ICAWG to establish a standard set of circuits (beyond the IEEE 123 test feeder) to allow for validation and testing through external stakeholders.

*Uniform process that is consistently applied*

The ICA methodologies are consistent with the four-step Baseline Method outlined in the ACR. SCE has developed python scripts designed to maintain consistent implementation of the Iterative and Streamlined Methods on all the feeders in Demo A, while minimizing manual engineering implementation of the ICA calculations. Additionally, SCE used a consistent manner when preparing the network models, when preparing the AMI data and managing the study and results.

*Complete coverage of service territory*

As part of Demo A, SCE implemented and demonstrated the ICA methodology in two selected DPAs. Based on the Demo A results, improvements to the ICA methodology such as computational efficiency techniques are proposed for the ICA process covering the entire service territory. This effort will be supported by activities such as CYME gateway to streamline circuit modeling creation and update.

The studies performed in Demo A were directed toward 3-phase radial feeders. Additional studies are required for determining ICA limitation on feeders which are operated as a "closed looped" network and single phase radials.

*Useful formats for results*

The ICA results are published via online maps as supported by the ICAWG and data is downloadable on a per feeder basis. The most practical and relevant scenario is displayed on the map so that DER developers can navigate through circuit sections based on the visual presentation to identify the locational variance of the DER Integration Capacity. The downloadable data files contain all the ICA results so that DER developers can query information to perform specific studies in order to identify the optimal locations for certain DER or DER portfolios. Both maps and downloadable data files are designed in a consistent style and are clearly explained through the inclusion of "keys" and documentations so that all California stakeholders can obtain similar data and visual aspects and can easily understand and utilize the information.

There may be room for improvement based on input from the ICAWG and other stakeholders. If certain functionalities are deemed critical to DER implementation, SCE can look to modify the maps in the future to accommodate new functionalities to the extent feasible.

### *Consistent with industry, state, and federal standards*

The power system criteria adopted in Demo A adheres to industry, state, and federal standards. Thermal criteria are based on equipment ratings established by manufacturers and design criteria established in CPUC General Orders 95 and 128. Steady state voltage criteria is determined by IOUs' Rule 2, which are drawn from American National Standard (ANSI) C84.1 - 2011 Range A. Transient voltage criteria align with IEEE recommended practice defined in IEEE Standard 1453-2015. Both protection and operational criteria are based on the EPRI hosting capacity methodology and align with IOU's system design and operating standards as well as interconnection standards

### *Accommodates portfolios of DER on one feeder*

The IOUs provided an ICA translator along with the ICA results calculated for inverter-based uniform generation and uniform load DERs. This ICA translator is designed to convert the technology agnostic ICA curves to any DER technologies or portfolios of DER technologies. Stakeholders can use this translator to generate the ICA values for their planned DER portfolios based on a customized DER output profile. This mechanism can provide the most representative ICA values for any DER technologies or DER portfolios comparing with ICA values based on typical DER profiles.

### *Reasonable resolution (a) spatial, (b) temporal*

SCE used granular geospatial circuit models and hourly load profiles to conduct the ICA. The integration capacity is evaluated at all three phase nodes of each primary line section within individual distribution feeders including the primary side of service transformers that feed customer premises. Demo A also adopted hourly time series analysis to evaluate the nodal integration capacity for 24 hours a day, for two days of every month of the year covering both the peak and minimum loading conditions.

### *Easy to update based on improved and approved changes in methodology*

SCE has been steadily working to improve the ICA methodologies since the DRP plan filing in 2015 and throughout Demo A. The methodologies are developed using a modular structure which eases the potential changes from long term refinement activities. The ICA also utilizes open scripting platforms within power flow tools to develop the automated batch process, which require less dependence on specific tool module updates from power flow tools.

It should be noted that while SCE has strived to develop the ICA tools with future improvements in mind, care should be taken not to underestimate the time and resources required to implement further upgrades. Each increase to the capabilities of the ICA tools comes with a commensurate increase in time, cost, and engineering resources to achieve such capabilities. In some cases, certain functionalities may not be possible until other foundational upgrades are in place.

*Easy to update based on changes in inputs (loads, DER portfolio, DER penetration, circuit changes, assumptions, etc.)*

As shown in the process flowchart, the ICA methodologies are designed based on a modular structure, which facilitates the integration of various inputs to the ICA calculation. In addition, various initiatives such as the integration of load forecasting tool with power flow tool and the streamline of circuit modeling update from GIS database are underway across IOUs to enhance the flexibility of the ICA process.

As noted above, SCE has attempted to foresee and accommodate some future improvements, but as with any new tool or process, there are unforeseen challenges that can and will arise as the tools evolve over time.

*Consistent methodologies across large IOUs*

SCE worked closely with the other IOUs to develop common ICA methodologies and processes including assumptions and power system criteria in order to ensure consistency. SCE believes the adopted ICA methodologies are aligned with the Baseline Method described in the ACR. In addition, comparative assessment using IEEE 123 node test feeders was performed in order to further ensure that the application of the ICA methodologies such as power flow tool and model parameter configuration where consistent among IOUs.

*Methodology accommodates variations in local distribution system, such that case by case or distribution planning area (DPA) specific modifications are not needed*

The ICA methodologies are based on fundamental circuit analysis functions and are designed for batch analysis which sufficient flexibility to address locational variance of system characteristics. The methodologies are able to be applied system wide without method customization or adjustment to accommodate difference throughout the distribution system.

## 9.4. Recommendations

The ACR has outlined topics for continued advancement and improvement of the ICA methodologies. These suggested topics are:

- Expansion of the ICA to single phase feeders;
- Ways to make ICA information more user-friendly and easily accessible (data sharing);
- Interactive ICA maps;
- Market sensitive information (type and timing of the thermal, reactance, or protection limits associated with the integration capacity on each line);
- Method for reflecting the effect of potential load modifying resources on integration capacity;
- Development of ICA validation plans, describing how ICA results can be independently verified;
- Definition of quality assurance and quality control measures, including revision control for various software and databases, especially for customized or “in-house” software;

Additional topics of ICA methodology refinement were suggested during Working Group meetings. These topics include:

1. Weather correlation;
2. "Click and claim" function;
3. More programmer friendly interface;
4. Alignment of ICA with other DER related activities (such as interconnection revision process, general rate cases, and the integrated resource planning proceeding) and other related working groups (such as the IDER Working Group and the Cost Effectiveness Working Group);
5. Visual presentation of additional growth scenarios to assist in planning;
6. Interaction between ICA and LNBA (Locational Net Benefit Analysis);

### *Initial Deployment (next 12 months)*

Following the ICA studies exercised during Demo A, SCE believes certain types of analyses are ripe for inclusion in the ICA process in the near term.

Expansion of the ICA to single phase feeders has been explored and is currently under development through analysis of one feeder. Once the single feeder analysis is complete and methodologies have been determined for implementation of single phase ICA, It may be appropriate and feasible for inclusion in the next year. It should be noted that ICA analysis on single phase feeders is dependent on the accuracy of the phasing information in the circuit model, which may not be accurate in all cases. SCE believes that although efforts are being madeto improve the phasing information in the circuit models, it will likely take longer than one year.

SCE will work with the ICAWG to discuss the data access issues including ways to make ICA information more user-friendly and easily accessible.

The ICA maps developed in Demo A provide a powerful tool for DER providers to site and size their projects. SCE believes that thoughtful use of the maps and data behind the maps will enable widespread deployment of DER without impacting the distribution system. After stakeholders have a chance to test and experience the ICA maps, SCE will work with ICAWG to identify possible improvements for a more interactive map with a more programmer friendly interface. Depending on the discussions, the actual implementation may take longer and become a long term refinement.

There was significant discussion during ICAWG meetings regarding a method of incorporating the ICA information into the Rule 21 Interconnection procedures. SCE strongly supports this concept, as long as sufficient technical detail is used to perform the ICA, which would allow the interconnection process to be expedited. SCE proposes that a limited set of ICA values sufficient to meet the requirements of the current Rule 21 process be calculated via the Iterative Method. SCE believes that Iterative Method is more appropriate as this method parallels what is currently used in the Rule 21 detailed study processes, and performs a full analysis on the network models. However, SCE recommends that only a selected set of data be calculated via the Iterative Method as it requires significantly more computational processing time, which would be difficult to complete for SCE's 4,500 circuits. SCE does not recommend leveraging the Iterative Method for calculating ICA to be used in cases such as planning. For planning, the Streamlined Method would be more efficient in producing the adequate ICA values. Therefore, SCE recommends that a "Blended ICA" approach be utilized for the near term where the Iterative Method is utilized to expedite the interconnection process, and the Streamlined Method is utilized to meet the needs of other use cases.

### *Long Term Improvements (2+ years)*

Load modifying resources, such as demand response, are generally controllable resources, which can have positive or negative impacts to the integration capacity. The uncertainties associated with these resources, arising from human behaviors, may present a different pattern. SCE will explore methods to reflect the effect of potential load modifying resources on integration capacity.

Accurate ICA results are important for stakeholders in developing their project plans, an ICA validation plan that enables the results to be independently verified is necessary and beneficial. SCE will explore options and propose quality assurance and quality control measures including revision control for various software and databases, especially for customized or "in-house" software.

While weather correlations can be a worthy upgrades to the ICA, they will also be very difficult to implement. For example, the current 576-hour analysis is made up of 'typical' high and low load days for each month, which are really a mixture of high and low load hours. This would make associating the ICA curve with a particular weather pattern impossible. The ICA would either need to change to a full 8760-hour analysis, or choose fixed days so that a weather correlation can be made. SCE believes that weather correlation is not necessary, as using a conservative approach (i.e., assume solar PV is at peak output even on a low load day) will serve DER providers well when considering where to site projects.

Implementing a "click and claim" function into the SCE's DERiM can provide significant value if implemented correctly in conjunction with the interconnection process requirements. It should be noted that significant technology advancements would be required to accomplish this functionality. SCE believes its Grid Interconnection Processing Tool (GIPT) may be capable of enabling such functionality in the future.

Aligning ICA enhancement with other DER related industry initiatives and working group activities can potentially avoid redundant or conflicting efforts, improve the methodologies in an integrated manner, and maximize the value of the studies. For example, the interaction between ICA and LNBA can not only feed valuable information to each other, but also provide meaningful information to the stakeholders in planning their projects.

The preparation of online map and downloadable data files in Demo A has shown that the data sizes are significant even for the two selected DPAs, which represent only a small portion of the entire service territory. While visual presentation of various scenarios can provide valuable information to assist in planning, the significant amount of information can also make the process cumbersome and confusing, which was also the reason why IOUs proposed to present the most practical and relevant scenario on the map and make other data downloadable for offline use, IOUs believe the marginal benefit of visually presenting more information may not be paid off by the effort required for both the developers and users.

## 9.5. Conclusions

Through this analysis, SCE met the compliance requirements as outlined in the ACR. In this demonstration project SCE:

- Tested two methodologies, the Iterative Method and the Streamlined Method.
- performed the analysis on two distinct DPAs composed of nine substation and 82 distribution feeders in total.
- Applied approved computation efficiency methodologies to reduce the time to complete the study without reducing accuracy.
- Determined ICA values for 576 hour composed of typical maximum and typical minimum day under the two scenarios of (1) no reverse power towards the transmission system and (2) irrespective of direction of power flow.
- Determine and implemented mapping and data sharing mechanisms.

Through this demonstration, SCE strived to find the proper balance of accuracy of results and computational time requirements to produce meaningful ICA values that would be useful for near-term use-cases, while also allowing for continued refinements of the methodologies and calculations for long-term applications. Based on this analysis, SCE believes that there are benefits for each of the two ICA methodologies. Thus, SCE proposes that a *Blended ICA Method* should be adopted for initial implementation of ICA across the SCE service territory.

This phase of the Integration Capacity Analysis helped informed SCE of the various challenges and requirements that must be addressed to be able to execute this type of analysis system wide. It also provided sufficient information to permit future ICAWG meetings to be more productive and efficient, and address the most critical needs.

Through the continued development of new tools and technology, improved methodologies, and adequate prioritization of needs, SCE believes that the ICA will continue to improve with the support of the regulatory and stakeholders.

# Appendix: ACR requirements compliance matrix

## a) Compliance Matrix

| Requirement | ACR Description | ACR | Document |
|---|---|---|---|
| **Load forecasting and DER growth scenarios** | IOUs shall use a transparent method for both load forecasting and DER growth in their ICA calculation methodology. DER growth scenarios will be approved in a separate Commission action. For purposes of both load forecasting and DER growth scenarios, Demonstration Project A shall be conducted using the following scenarios:<br>• 2-year growth scenario as required in the Guidance and described above; and<br>• Growth scenarios I and III as proposed in the DRP Applications.<br>• Each scenario shall be conducted in two different DPAs that are selected to represent the range of physical and electrical conditions within the respective IOU distribution systems. | Section 1.1, p5 | Final Report Chapter 4.3.1, 5.1.2, 5.2, 5.3 and downloadable data files |
| **Baseline Method Steps** | | | |
| **Establish distribution system level of granularity** | Analysis shall be performed down to specific nodes within each line section of individual distribution feeders. Nodes shall be selected based on impedance factor, which is the measure of opposition that a circuit presents to electric current on application of voltage. Minimum and maximum (i.e. best and worst case) ranges of results shall be evaluated using lowest and highest impedance. | Section 1.3, p 6 | Final Report Chapter 4.2 |
| **Model and extract power system data** | A Load Forecasting Analysis Tool (e.g. Load SEER) shall be used to develop load profiles at feeder, substation and system levels by aggregating representative hourly customer load and generation profiles.8 Load profiles shall be created for each DPA. The load profiles are comprised of 576 data points representing individual hours for the 24-hour period during a typical low-load day and a typical high-load day for each month (2 days * 24 hrs * 12 months = 576 points). | Section 1.3, p 7 | Final Report Chapter 4.3 |

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| | A Power Flow Analysis Tool (e.g. CYMEDist for PG&E and SCE and Synergi Electric for SDG&E) shall be used to model conductors, line devices, loads and generation components that impact distribution circuit power quality and reliability. The Power Flow Analysis Tool shall be updated with the latest circuit configurations based on changes to the GIS asset map per the current practice of each utility. | | |
| Evaluate power system criterion to determine DER capacity | The Load Forecast Tool and Power Flow Analysis Tool shall be used to evaluate power system criterion for the nodes and line sections that determine DER capacity limits on each distribution feeder. ICA results are dependent on the most limiting power system criteria. This could be any one of the factors listed in PG&E's Table 2-4 in their DRP Application under "Initial Analysis" and summarized below: (a). Thermal Criteria – determined based on amount of additional load and generation that can be placed on the distribution feeder, without crossing the equipment ratings. (b). Power Quality / Voltage Criteria – voltage fluctuation calculated based on system voltage, impedances and DER power factor. Voltage fluctuation of up to 3% is part of the system design criteria for all three utilities. (c). Protection Criteria – determined based on required amount of fault current fed from the sub-transmission system due to DER operation. This is an area that the Working Group shall further develop. A potential starting point is the approach of PG&E as follows: Reduction of reach concept for generators was used with 10% evaluation as a flag for issues with the protection schemes. PG&E assumes that DER inverters contribute 120% rated current compared to 625% rated current from synchronous machines for a short circuit on the terminals. (d). Safety/Reliability Criteria – determined based on operational flexibility that accounts for reverse power flow issues when DER/DG is generating into abnormal circuit operating scenarios. Other | Section 1.3, p 7-9 | Final Report Chapter 4.4 |

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| | limitations supporting the safe and reliable operation of the distribution system apply. | | |
| Calculate ICA results and display on online map | The ICA calculations shall be performed using a layered abstraction approach where each criteria limit is calculated for each layer of the system independently and the most limiting values are used to establish the integration capacity limit. The ICA calculations shall be performed in a SQL11 server database or other platform as required for computation efficiency purposes. The resulting ICA data shall be made publicly available using the Renewable Auction Mechanism (RAM) Program Map. The ICA maps shall be available online and shall provide a user with access to the results of the ICA by clicking on a feeder displayed on the map. For the purposes of Demonstration Project A, the current utility map displays shall be used until further direction on a common approach is provided by the Commission. | Section 1.3, p 9 | Final Report Chapter 4.1.3; 7 |
| Specific Modifications to Include in Baseline Method | | | |
| Quantify the Capability of the Distribution System to Host DER | (a) Devices that contribute to reactive power on the circuit (e.g. capacitors, etc.) and their effect on the power flow analysis shall be included in the power flow model | Section 1.4, P 9-10 (and Section 1.1, p 1-2) | Final Report Chapter 4.3.2 |
| | (b). Power flow analysis shall be calculated across multiple feeders, whenever feasible for more accurate ICA values. All feeders that are electrically connected within a substation shall be included in this analysis. | Section 1.4, P 9-10 | Final Report Chapter 4.3.2 |
| | (c). The ICA shall be modified to reflect DERs that reduce or modify forecast loads. | Section 1.4, P 9-10 | Final Report Chapter 4.3.1 |
| | (d). Disclose any unique assumptions utilized to customize the power flow model of each IOU and all other calculation that could impact the ICA values. | Section 1.4, P 9-10 | Final Report Chapter 4.3.2 |
| Common Methodology Across All Utilities | The "baseline" methodology with modifications described in this ruling will be used as a provisional common ICA methodology used by all IOUs in the Demonstration A Projects. At this time, SCE and SDG&E are required to adopt the | Section 1.4, p 10 (and Section 1.1, p 2) | Final Report Chapter 4.1 |

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| | modified baseline methodology described in this ruling, which is derived from PG&E's basic methodology. SCE and SDG&E's power flow analysis and load forecast tool methodologies should be adapted, as required, using PG&Es methodology as the basis. | | |
| Different Types of DERs | (a) The methodology shall evaluate the capacity of the system to host DERs using a set of 'typical' DER operational profiles. PG&E has developed a set of profiles that provide a starting point. These profiles are: Uniform Generation, PV, PV with Tracker, EV – Residential (EV Rate), EV – Workplace, Uniform load, PV with Storage, Storage – Peak Shaving, EV – Residential (TOU rate) | Section 1.4, p 11 (and Section 1.1, p 2) | Final Report Chapter 8.2 |
| | (b). ICA shall quantify hosting capacity for portfolios of resource types using PG&E's approach with representative portfolios of i. solar, ii. solar and stationary storage, iii. solar, stationary storage, and load control and iv. solar, stationary storage, load control, and EVs. | Section 1.4, p 11 | Final Report Chapter 8.2 |
| | (c). Utilities shall propose a method for evaluating DER portfolio operational profiles that minimize computation time while accomplishing the goal of evaluating the hosting capacity for various DER portfolios system-wide. | Section 1.4, p 11-12 | Final Report Chapter 8.2 |
| | (d) The ICA Working Group shall identify additional DER portfolio combinations | Section 1.4, p 12 | Final Report Chapter 8.2 |
| Granularity of ICA in Distribution System | Locational granularity of ICA is defined as line section or node level on the primary distribution system, as specified in the PG&E methodology | Section 1.4, p 12 (and Section 1.1, p 2) | Final Report Chapter 4.2 |
| Thermal Ratings, Protection Limits, Power Quality (including Voltage), and Safety Standards | (a) Include all the different types of defined power system criteria and subcriteria in the analysis. i. In Table 2-4 in its DRP application, PG&E has indicated a set of power system criteria to be used in a "Potential Future Analysis." All items on this list should be incorporated to the extent feasible initially, with the objective of complete inclusion as the capabilities become available. | Section 1.4, p 12 (and Section 1.1, p 2) | Final Report Chapter 4.4, Appendix b) |

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| | (b) Protection Limits used in ICA – The IOUs shall agree upon on a common approach to representing protection limits in the ICA. | Section 1.4, p 12 | Final Report Chapter 4.4.6 |
| | (c) Utilities shall provide documentation to describe the ICA limit criteria and threshold values and how they are applied in the Demonstration A Projects, in an intermediate status report, due Q3 2016. | Section 1.4, p 13 | SCE's Intermediate Status Report for Demonstraiton Project A |
| | (d). Utilities shall provide documentation to identify and explain the industry, state, and federal standards embedded within the ICA limitation criteria and threshold values, and include this in Final Report due early Q4 2016. | Section 1.4, p 13 | Final Report Chapter 4.4 |
| | (e). Included with ICA results for each feeder provide i. Feeder-level loading and voltage data, ii. Customer type breakdown, iii. Existing DER capacity (to the extent not already available). | Section 1.4, p 13 | Final Report Chapter 7; Online map; downloadable data files |
| | (f). Identify feeders where sharing the information in paragraph "e" violates any applicable data sharing limitations. | Section 1.4, p 13 | N/A |
| | (g). ICA results should include detailed information on the type, frequency, timing (diurnal and seasonal) and duration of the thermal, voltage, or system protection constraints that limit hosting capacity on each feeder segment. The information shall be in a downloadable format and with sufficient detail to allow customers and DER providers to design portfolios of DER to overcome the constraints. This information may include relevant load and voltage profiles, reactive power requirements, or specific information related to potential system protection concerns. | Section 1.4, p 13-14 | Final Report Chapter 5; downloadable data files |
| Publish the Results via Online Maps | (a) All information made available in this phase of ICA development shall be made available via the existing ICA maps in a downloadable format. The feeder map data shall also be available in a standard shapefile format, such as ESRI ArcMap Geographic Information System (GIS) data files.21 The maps and associated materials and download formats shall be consistent across all utilities and should be clearly | Section 1.4, p 14 (and Section 1.1, p 2) | Final Report Chapter 7; downloadable data files |

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| | explained through the inclusion of "keys" to the maps and associated materials. Explanations and the meanings of the information displayed shall be provided, including any relevant notes explaining limitations or caveats. Any new data types developed in the ICA Working Group shall be published in a form to be determined in the data access portion of the proceeding. | | |
| | (b) Existing RAM map information and ICA results shall be displayed on the same map. RAM information shall be the default information displayed on that map with ICA data available if the user specifies it. | Section 1.4, p 14 | Final Report Chapter 7 |
| Time Series or Dynamic Models | ICA shall utilize a dynamic or time series analysis method as specified in the Guidance. This analysis shall be consistent among the three IOUs. The IOUs currently use different power flow analysis tools that may implement a time series analysis differently. The methodology used by the three IOUs should therefore be based on capabilities that are common among the tools that support a consistent result. IOUs shall consult with the ICA Working Group to ensure that the power flow analysis tools use an equivalent approach to dynamic or time series analysis. | Section 1.4, p 14-15 (and Section 1.1, p 2) | Final Report Chapter 4.1 |
| Avoid Heuristic approaches, where possible | There are no new modifications based on this Guidance requirement | Section 1.4, p 15 (and Section 1.1, p 2) | Final Report Chapter 4.4 |
| General Requirements | | | |
| Power Flow Scenarios | The Guidance Ruling required the IOUs to model two scenarios in their Demonstration A projects: (a) The DER capacity does not cause power to flow beyond the substation busbar. (b) The DERs technical maximum capacity is considered irrespective of power flow toward the transmission system. | Section 2, p 15 (and Section 1.1, p 4) | Final Report Chapter 4; 5 |

| | | | |
|---|---|---|---|
| **Project Schedule** | Demonstration A project schedules proposed in IOU Applications are modified and shall commence immediately with the issuance of this Ruling. | Section 2, p 16 | SCE's Implementation Plan for Demonstration Proejcts A |
| **Project Locations** | Demonstration A project locations proposed in the Applications are modified and shall include two DPAs that cover as broad a range as possible of electrical characteristics encountered in the respective IOU systems (e.g., one rural DPA and one urban DPA). The IOUs shall clarify if their originally proposed Demonstration A project locations satisfies one of the two required DPAs and what their other proposed DPA(s) are. The IOUs shall also justify in their detailed plans the basis for choosing each DPA for the Demonstration Projects. | Section 2, p 16 (and Section 1.1, p 3) | Final Project Chapter 3 |
| **Project Detailed Implementation Plan** | The IOUs shall submit detailed implementation plans for project execution, including metrics, schedule and reporting interval. To the extent practicable, the IOUs shall consult with the ICA Working Group on the development of the plan. The plan shall be submitted to the CPUC within as a status update within 45 days of this ruling and served to the R.14-08-013 service list. The ICA Demo A Plan shall include (a) Documentation of specific and unique project learning objectives for each of the Demonstration A projects, including how the results of the projects are used to inform ICA development and improvement; (b). A detailed description of the revised ICA methodology that conforms to the guidance in Section 1.3 and Section 1.4 above, including a process flow chart. (c). A description of the load forecasting or load characterization methodology or tool used to prepare the ICA; (d). Schedule/Gantt chart of the ICA development process for each utility, showing: i. Any external (vendor or contract) work required to support it. ii. Additional project details and milestones including, deliverables, issues to be tested, and tool configurations to be tested; (e). Any | Section 2, p16-18 | SCE's Implementation Plan for Demonstration Proejcts A |

| | | | |
|---|---|---|---|
| | additional resources required to implement Project A not described in the Applications; (f). A plan for monitoring and reporting intermediate results and a schedule for reporting out. At a minimum, the Working Group shall report out at least two times over the course of the Demonstration A project: 1) an intermediate report; and 2) the final report. (g). Electronic files shall be made available to the CPUC Energy Division and ORA to view and validate inputs, models, limit criteria, and results. Subject to appropriate confidentiality rules, other parties may also request copies of these files; (h). Any additional information necessary to determine the probability of accurate results and the need for further qualification testing for the wider use of the ICA methodology and to provide the ultimate evaluation of ex-post accuracy. (i). ORA's proposed twelve (12) criteria or metrics of success to evaluate IOU ICA tools, methodologies and results are adopted and should be used as guiding principles for evaluating ICA. | | |

## b) Criteria Matrix

| | Streamlined | Iterative |
|---|---|---|
| | SCE | SCE |
| **Thermal** | | |
| – Substation Transformer | ✓ | * |
| – Circuit Breaker | ✓ | ✓ |
| – Primary Conductor | ✓ | ✓ |
| – Main Line Devices | ✓ | ✓ |
| – 3 phase Tap Line Devices | ✓ | ✓ |
| – Service Transformer | | |
| – Secondary Conductor | | |
| – Transmission Line | | |
| **Voltage / Power Quality** | | |
| – Transient Voltage | ✓ | ✓ |
| – Steady State Voltage | ✓ | ✓ |
| – Voltage Regulator Impact | ✓ | ✓ |
| – Substation Load Tap Changer Impact | ** | ** |
| – Harmonic Resonance / Distortion | | |
| – Transmission Voltage Impact | | |
| **Protection** | | |
| – Protective Relay Reduction of Reach | ✓ | ✓ |
| – Fuse Coordination | | |
| – Sympathetic Tripping | | |
| – Transmission Protection | | |
| **Safety/Reliability** | | |
| – Islanding | *** | *** |
| – Transmission Penetration | ✓ | * |
| – Operational Flexibility | ✓ | ✓ |
| –Transmission System Frequency | | |
| –Transmission System Recovery | | |

| Legend | |
|---|---|
| Included | ✓ |
| See Notes | * |
| Not in Demo Scope | |
| Not Applicable | |

*Not evaluated directly in power flows, but applied post analysis. SCE will determine it is necessary to evaluate substation transformer with an Iterative Method

** None of the substation within Demo A had LTC so this was used in the Demo.

*** SCE's protection practices rely on UL certification process as well as other protection mechanisms to maintain system safety and reliability without requiring additional protection systems to address unintentional islanding concerns.

# Appendix B

# Demonstration Project B Final Report

# Southern California Edison Distribution Resources Plan Demonstration Project B

Locational Net Benefit Analysis Final Report

## Table of Contents

## 1. Executive Summary

Pursuant to the May 2, 2016 *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B* ("ACR"),[1] Southern California Edison (SCE) submits this final report for Demonstration Project B (Demo B) which demonstrates the approved Locational Net Benefit Analysis (LNBA) methodology within one selected Distribution Planning Area (DPA). In this final report, SCE demonstrates its compliance with the ACR, which requires:

- Selection of a DPA that includes different types of distribution infrastructure projects within different time horizons for possible deferral.
- Application of the approved LNBA methodology to: a) identify potentially deferrable distribution infrastructure projects; b) calculate LNBA results for these projects under two DER growth scenarios; and c) develop DER requirements necessary to defer the project.
- Depiction of the LNBA results in an online heat map as a layer along with the Integration Capacity Analysis (ICA) results.

SCE supports the Commission's goal of integrating DERs into the utilities' distribution planning, operations and investment processes. SCE, in its recently released whitepaper "The Emerging Clean Energy Economy,[2]" outlined a similar vision to accelerate the transition to a clean, reliable energy future that includes a high penetration of DERs. SCE's whitepaper describes the "plug-and-play" future that SCE envisions for the electric grid, by facilitating customer choice of new technologies, creating opportunities for DERs to provides grid services, and modernizing the grid to ease integration and optimization of DERs. Realizing this shared vision of a modernized, digital power system will take a significant effort from all stakeholders over many years, and efforts such as Demo B are important steps towards achieving our common objectives.

The ACR dictates the selected DPA must have both near term (0-3 years lead time) and longer term (3 or more years lead time) projects; moreover, the DPA must have at least one voltage support/power quality or reliability/resiliency project, in addition to one or more capacity related projects. To meet these requirements, SCE selected a portion of its Rector System as the DPA for Demo B. This area is located in Tulare County, a part of California's Central Valley, in SCE's territory. This DPA encompasses five distribution substations, serving mostly agricultural customers with a mix of residential and commercial customers as well. Due to the drought condition, this area has experienced rapid load growth, especially in

[1] R.14-08-013, Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, May 2, 2016, Appendix A at pp. 37.
[2] SCE's whitepaper can be found at: http://www.edison.com/content/dam/eix/documents/our-perspective/der-dso-white-paper-final-201609.pdf

agricultural pumping load. This condition requires several infrastructure upgrade projects and therein provides an ideal setting for this demonstration to perform the LNBA studies.

For the purposes of Demo B, the IOUs consulted with the LNBA Working Group to identify electric services that Distributed Energy Resources (DERs) can provide. Specifically, as per the Competitive Solicitation Framework Working Group final report[3], these services were defined as: transmission and distribution capacity, voltage support, reliability services related to back-ties, and resiliency services related to microgrids.

DERs have the potential to provide additional electric services such as: conservation voltage reduction and volt/VAR optimization, equipment life extensions, and ancillary services. However, due to the challenges of existing technologies, communications and controls, and regulatory processes that are required to fully understand the effects or realize the benefits of DERs, these services are not expressly included in Demo B. However, with technology improvements, DERs may provide these services in the future and be included in the LNBA methodology.

To identify projects that are potentially deferrable by DERs, after agreeing upon the electric services that DERs can provide, SCE examined all the infrastructure upgrade projects identified in SCE's distribution planning process, maintenance work notifications from SCE's Distribution Inspection and Maintenance Program, and projects in SCE's reliability program within the Demo B DPA.

In the planning scenario, there are five projects identified as potentially deferrable by DERs. These projects include two distribution capacity upgrade projects (one near-term and one mid-term), two subtransmission capacity upgrade projects (one near-term and one long term), and one near-term subtransmission voltage support project. The scope of distribution capacity projects includes increasing substation capacity by upgrading transformers, installing new distribution circuits, and improving power factor by installing new capacitors. The scope of subtransmission capacity projects includes constructing new underground subtransmission line and reconductoring smaller conductors with higher capacity conductors. The subtransmission voltage support project will install a new switched capacitor bank at one substation. Engineering studies were performed to determine the DER requirements, including the peak DER load reduction requirement and time/duration of the need, necessary to defer the project.

Additional DER growth can offset some of the load growth in the area and mitigate or even eliminate the need for the planned grid upgrade projects. In the very high DER growth scenario published in SCE's Distribution Resources Plan[4], only one distribution capacity

[3] Competitive Solicitation Framework Working Group Final Report Filed by Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-M), San Diego Gas & Electric Company (U 902-E), and Southern California Gas Company (U 904-G), Aug 1, 2016

[4] Application of Southern California Edison Company (U 338-E) for Approval of Its Distribution Resources Plan, July 1, 2015, at pp. 76

project has a need within the planning horizon (i.e., project needed in 2025), while the other four identified deferrable projects are no longer needed within the 10-year planning horizon.

The ACR defined a primary analysis and a secondary analysis for IOUs to determine the benefits[5] of DERs in each location within the DPA, acknowledging the challenges of performing the secondary analysis within Demo B project time frame[6]. As such, SCE decided to pursue the primary analysis for the LNBA methodology. The IOUs selected E3 to develop a LNBA tool that allows for the calculation of the LNBA results, which represent the potential value of deferring a project. In addition, this tool can also calculate the system avoided costs, such as avoided generation capacity and avoided greenhouse gas emission. The system avoided costs are the same for all the locations and do not present locational difference.

SCE utilized this LNBA tool to incorporate the project cost information and DER requirements for the project deferral; the tool was also used to calculate the LNBA results for each of the five deferrable projects in the planning scenario and the one deferrable project in the very high DER growth scenario. The LNBA result is calculated as the value of a three-year deferral of the project divided by the maximum need in kilowatts (kW) over that same three-year period. In order to preserve market fairness, the actual LNBA results are not provided; instead, the LNBA results are matched to the corresponding dollar symbol (e.g., $, $$) indicating the range of the deferral value. These results in the symbolic format are presented on the Demo B heat map, which is publicly available. If a circuit doesn't have any deferrable projects associated with it and therefore has no T&D deferral value, it is assigned a $ for the system avoided costs. Other circuits are assigned an LNBA result between $$ and $$$$ depending on the T&D deferral value. The LNBA results for the deferrable projects studied in Demo B have covered the full range (from $$ to $$$$) demonstrating the locational difference in the benefits of DERs.

Through this demonstration, SCE explored different methodologies and analyses to assess the locational benefits of DERs to achieve grid upgrade project deferral. The results clearly show the locational difference. Therefore, SCE believes the information provided in its filing of Demo B final report, heat map, and downloadable dataset will help DER developers to choose the siting of future projects. At the same time, SCE also identified several areas where the process needs to be streamlined and tools need to be enhanced in order to enable a system-wide deployment of the LNBA methodology. SCE believes LNBA methodologies will continue to evolve, processes will become more efficient, and LNBA results will be more accurate. SCE appreciates that Demo B provided a learning opportunity to pilot the LNBA methodology and looks forward to participating in refinements to improve the output for all stakeholders.

This final report is organized into the following chapters:

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[5] The LNBA value does not include DER costs as a component in Demo B.

[6] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B, August 23, 2016, at pp. A26-A27.

- Chapter 2 describes the background of Demo B, including the project history, project objectives, the LNBA components, and definition of "net", as well as an overview of the LNBA tool and the heat map.
- Chapter 3 presents electric services that DERs can and cannot provide as part of Demo B.
- Chapter 4 describes SCE's distribution planning area (DPA), which is a portion of the Rector Subtransmission System, and provides a high level overview of load and DER forecasts.
- Chapter 5 provides detailed information regarding deferrable projects in SCE's DPA.
- Chapters 6 and 7 provide a high level overview of the maintenance and reliability projects, respectively.
- Chapters 8 and 9 detail the functionality of the LNBA tool and provide a walkthrough of the two major parts of the LNBA tool: (1) project deferral benefit and (2) system-level avoided cost.
- Chapter 10 discusses the lessons learned from Demo B and the future refinements that can improve the methodology and the process.
- Appendices presents additional information on SCE's Demo B heat map, LNBA tool documentation, and the compliance matrix matching the Demo B requirements established in the ACR to the details in this final report, heat map, and/or the LNBA tool.

## 2. Demo B Background and Objectives

### Background

On August 14, 2014, the California's Public Utilities Commission (CPUC or Commission) issued Rulemaking (R.) 14-08-013 which established guidelines, rules, and procedures to direct California's investor-owned electric utilities (Utilities or IOUs) to develop their Distribution Resources Plan (DRP). On February 6, 2015, the Commission issued a Final Guidance[7] to establish requirements for the IOUs in filing their DRPs. This Final Guidance included a requirement that each IOU propose a demonstration project (Demo B) that performs the Commission approved Locational Net Benefit Analysis (LNBA) methodology for one DPA. The LNBA helps identify the benefits that DERs can provide in a given location, particularly benefits associated with meeting a specific distribution need. On July 1, 2015, the three IOUs filed DRPs in compliance with the Final Guidance. On February 1, 2016, a workshop on LNBA was held.

The Commission subsequently issued an ACR on May 2, 2016 and a revised ACR on August 23, 2016.

### Objectives

The objectives of Demo B are to:

- Select a DPA that includes:
    - "one near-term and one longer-term distribution infrastructure project for possible deferral;"[8] and
    - "at least one voltage support/power quality- or reliability/resiliency-related deferral opportunity in addition to one or more capacity-related opportunities"[9]
- Apply the approved LNBA methodology to identify potential distribution infrastructure projects for deferral, calculate LNBA results under two DER growth scenarios, and develop DER requirements necessary to defer the project.
- Display results in an online heat map as a layer along with the Integration Capacity Analysis (ICA) results.

This detailed final report describes how SCE fulfilled the Commission's requirements for Demo B. Specifically, this report: (1) details methods used to calculate locational benefits in Demo B; (2) demonstrates how each IOU determined locational variability of benefits within

[7] Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning, ("Final Guidance"), February 6, 2015.

[8] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, August 23, 2016, at pp. A25.

[9] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, August 23, 2016, at pp. A25.

a selected DPA and discusses the results; (3) develops project requirements that must be met for DERs to defer projects; and (4) tests methods and applies lessons learned to future LNBA work. This report also details the specific requirements defined in the ACR (*see* Appendix 3 of this final report), mapping the location where each requirement is addressed in either this report, the online heat map, or downloadable dataset.

Consistent with the requirements of the ACR, the following chapters of this final report reflect a collaborative effort between SCE, Pacific Gas & Electric Company (PG&E), and San Diego Gas & Electric (SDG&E): Chapter 2 – Background and Objectives, Chapter 3 – Electric Services, Chapter 8 – Project Deferral Benefit Calculation, and Chapter 9 – Other LNBA Components Calculation. In addition, the three IOUs engaged Energy and Environmental Economics (E3) to develop an excel tool for estimating location-specific avoided costs of installing DERs. This LNBA tool is based on a specific approved LNBA methodology framework provided to the utilities by the ACR for Demo B. Appendix 2, which presents the proposed LNBA methodology, was written by E3.

Many of the decisions and approaches described in this report were taken in consultation with the LNBA Working Group, which was formed as a result of the ACR. In particular, SCE understood that the LNBA Working Group expressed strong support for using technology-agnostic approaches to evaluate location-specific benefits in Demo B. The methods and tools reflected in this report are therefore designed, to the maximum extent possible, to be technology-agnostic and permit evaluation of any DER or combination of DERs.

Demo B provides an initial demonstration of a number of new planning analyses. It is SCE's expectation that these methods will continue to evolve as more experience is gained. SCE believes the results of this demonstration will help inform a Commission Decision to update the LNBA process for the first system-wide implementation. SCE expects that this initial LNBA public tool will provide useful information to DER developers in choosing where to site DER projects. SCE also expects that portions of the analyses developed in this demonstration will ultimately be incorporated into its annual planning processes. Specifically, the analysis of identifying which conventional distribution projects may be deferred by DER solutions relates specifically to the Deferral Framework to be developed in Sub-track 3 of Track 3 of the DRP proceeding[10]. SCE looks forward to engagement with the Commission and Stakeholders to refine these tools and expand their usefulness.

## 2.1. LNBA Components for Demo B

The ACR defined two methodologies–a primary analysis or secondary analysis–by which IOUs could determine the benefits of DERs in each location within its selected DPA(s).[11] Given that the secondary analysis would require significant time to develop additional

[10] Assigned Commissioner's Ruling on Track 3 Issues, October 21, 2016, at pp. 7.

[11] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, August 23, 2016, at pp. A26-A27.

methodologies and the time constraints for Demo B, as acknowledged in the ACR,[12] SCE decided to pursue the primary analysis (as defined in table 2 of the ACR, reproduced below). However, the LNBA Tool is designed to easily incorporate many refinements, including some that are reflected in the secondary analysis.[13]

**Table 2 Approved LNBA Methodology Requirements Matrix for Demonstration Project B**

| Components of avoided costs | Proposed LNBA in IOU Filings | Primary Analysis | Secondary Analysis |
|---|---|---|---|
| *from DERAC* | *from IOU applications* | *Required* | *Optional additional* |
| **Avoided T&D** | **Sub-Transmission / Substation / Feeder** | **As proposed but with modifications (1)** | **As proposed but with modifications (1)** |
| | **Distribution Voltage / Power Quality** | **As proposed but with modifications (1)** | **As proposed but with modifications (1)** |
| | **Distribution Reliability / Resiliency** | **As proposed but with modifications (1)** | **As proposed but with modifications (1)** |
| | **Transmission** | **As specified herein (2)** | **As specified herein (2)** |
| Avoided Generation Capacity | System and Local RA | Use DERAC values | Use DERAC values with location-specific line losses (3) |
| | Flexible RA | Use DERAC values with flexibility factor (4) | Use DERAC values with flexibility factor (4) |
| Avoided Energy | Use LMP prices to determine | Use DERAC values | As proposed but with modifications regarding use of LMP prices (5) and location-specific losses (3) |
| Avoided GHG | incorporated into avoided energy | Use DERAC values | As proposed |
| Avoided RPS | similar to DERAC | Use DERAC values | As proposed |
| Avoided Ancillary Services | similar to DERAC | Use DERAC values | As proposed |
| *additional to the DERAC* | Renewable Integration Costs | values or descriptions of these benefits (6) | values or descriptions of these benefits (6) |
| | Societal avoided costs | values or descriptions of these benefits (6) | values or descriptions of these benefits (6) |
| | Public safety costs | values or descriptions of these benefits (6) | values or descriptions of these benefits (6) |

The benefits in the LNBA methodology include: avoided transmission and distribution (T&D) costs; avoided generation capacity costs; avoided energy costs; avoided greenhouse gas (GHG) costs; avoided renewable portfolio standard (RPS) costs, avoided ancillary services costs; renewable integration costs; and, if quantifiable, societal and public safety costs. The avoided T&D costs are further broken down into four categories: (1) sub-transmission, substation, and feeder; (2) distribution voltage or power quality; (3) distribution reliability or resiliency; and (4) transmission. Similarly, avoided generation capacity costs are further broken down into two categories: (1) system and local resource adequacy (RA); and flexible

[12] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, August 23, 2016, at pp. A27.

[13] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, August 23, 2016, at pp. A26-A38.

RA. The non-T&D components are referred to in this report generally as system-level avoided costs.

## 2.2. Definition of Net in Demo B

In a typical net benefit analysis, total net benefits represent the present value of benefits minus the present value of costs. However, for purposes of Demo B, table 2 of the ACR,[14] quoted above in section 2.1, defines the LNBA as the combined net present value of the components detailed in the paragraph above. The ACR does not include DER costs as components of Demo B. SCE notes, however, the value of each component can be either positive or negative. For example, an energy storage device that operates to reduce feeder peak load may have a negative energy avoided cost if the feeder peak occurs when California Independent System Operator (CAISO) prices are lower than the prices during charging times.[15]

## 2.3. LNBA Tool Overview

To calculate the LNBA values, the IOUs engaged E3 to develop an LNBA tool for Demo B.[16] This tool incorporates the primary analysis components as describe in Table 2 of the ACR[17] and is divided into two major parts. The first part, a project deferral benefit module, calculates the indicative value of deferring a specific capital project. The second part, a system-level avoided cost module, estimates the system-level avoided costs given a user-defined DER solution. The summation of results from both modules provides the avoidable cost for a given DER solution at a specific location. Users provide an hourly profile corresponding to the DER solution of interest. For any DER solution, expressed as an Hourly DER Profile, the LNBA tool provides two quantitative results corresponding to the two modules described above: (1) an indicative value of the T&D deferral if the solution meets the projects' need requirements; and (2) an estimate of the system-level avoided costs based primarily on E3's DERAC tool.

The project deferral benefit module allows users to input various capital assumptions for deferrable projects and calculate the benefit of deferring such projects. Users need to define various financial inputs, such as the cost of the capital project, discount rate, inflation rate, deferral duration, and revenue requirement multiplier. Similarly, users need to define various project requirements, such as the project driver, electrical characteristic duration, scale, and time of need, loss factors, etc.[18] For the purpose of Demo B, SCE will provide inputs for project requirements for the projects identified as deferrable. SCE will also

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[14] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, August 23, 2016, at pp. A27-A28.
[15] Locational Net Benefit Analysis Working Group presentation, July 26, 2016, at pp. 12-16.
[16] The LNBA tool v2.11 and the E3 LNBA Tool Documentation (Appendix 2) can be found at: https://e3.sharefile.com/d-sb2965cf362c48399
[17] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, August 23, 2016, at pp. A27-A28.
[18] Locational Net Benefits Analysis Working Group presentation, November 16, 2016, at pp. 18-23.

provide values for certain financial variables. Further discussion of inputs and sources is provided in Chapter 8.

The system-level avoided cost module calculates the estimated value of system-level avoided costs. These costs are composed of avoided generation capacity costs, avoided energy costs, avoided GHG costs, avoided RPS costs, avoided ancillary services costs, and renewable integration costs that exist for delivery of energy at any point on the system. Avoided societal and public safety costs were not quantifiable and thus were not included in the LNBA Tool for Demo B; however, consistent with commission guidance,[19] a qualitative description of societal and public safety benefits is included in Section 9.7 of this final report. Once a user inputs assumptions into the tool, such as an hourly generation profile and contracted life, the module calculates the value of each system-level avoided cost components. Since these costs are at the system level, the system-level avoided cost results will not vary within the DPA of Demo B.[20] The system level avoided cost components were derived directly from E3's DERAC[21] as outlined within the ACR.

## 2.4. Heat Maps Overview

The heat map associated with Demo B provides a visual depiction of Demo B's deferrable project results, calculated using the project deferral module of the LNBA tool. Since values calculated from the system-level avoided cost in Demo B are the same for all locations in the DPA, the heat map does not reflect these LNBA components. Results for the heat map are further separated by six layers consisting of three time periods—short, medium, and long term, as directed by the Commission[22]—each depicted under two DER growth scenarios. There are two additional layers that map the two DER growth scenarios to the DPA.[23] The Demo B heat map is on the same platform as the ICA map, enabling users to access ICA and LNBA data through the same interface. A link to SCE's heat map with access instructions is provided in Appendix 1.

## 2.5. CPUC Requirements and Deliverables

The ACR details a number of requirements and deliverables to be met as part of Demo B. The final deliverables for Demo B include this final report, a heat map displaying LNBA results, a downloadable dataset detailing the Demo B data, and the LNBA tool. In order to ensure that the requirements of the ACR are met, SCE has provided a table (Appendix 3)

[19] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, August 23, 2016,, p. 27, "Societal Avoided costs.... Values or descriptions of these benefits"
[20] Locational Net Benefits Analysis Working Group presentation, November 16, 2016, at pp. 18-23.
[21] https://ethree.com/public_projects/cpuc4.php
[22] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, August 23, 2016,, p. 28.
[23] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, August 23, 2016,, p. 32.

that maps the specific ACR requirements and identifies the location (in the three final deliverables) where SCE addressed each requirement.

## 3. Electric Services in Demo B

Sec. 4.4.1(A) of the ACR requires the IOUs to identify the full range of electric services that result in avoided costs for all locations within the DPAs selected for analysis. These must include electric services associated with distribution grid upgrades identified in (i) the utility distribution planning process, (ii) circuit reliability improvement process and (iii) maintenance process.[24]

To accurately value DERs and their services, SCE must identify gaps in available services. The LNBA methodology proposed by the Commission requires SCE to consider the full range of electric services that DERs can provide; this includes electric services that are internal (utility owned) and external (third party providers) to the utility, both of which can potentially result in an "avoided cost."[25] To quantify the potential reduction in investment and to ensure sustainability and reliability of services, each service should also be compared to the conventional "wire-based" methods.

Generally speaking, the electric services should address the two key planning processes (planning for capacity and planning for reliability), as well as the need to ensure safe operation and timely maintenance of the system. That is, electric services are associated with three core functions:

- Utility distribution capacity planning processes
- Circuit reliability/resiliency improvement processes, and
- Safety/maintenance processes

In order to investigate the type and value of the services that can be provided by DERs, each service will be characterized from the following perspectives:

- How the service is provided today (i.e. conventional method)
- How DERs can provide the service

Several challenges exist that require modification to current practice and technology in order to optimize the capability of DERs.

- Modifications to engineering practices, such as protection design/coordination, changes in voltage levels, load/DER forecast accuracy, and capacity planning processes
- Need for technology advancement related to monitoring and communication with DERs. This is required to ensure DERs are performing as expected and optimize operation to meet electric system needs. Advancement in communication between grid devices and DERs can also enable the potential operation of future microgrids.

[24] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, August 23, 2016, at pp. A29.

[25] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, August 23, 2016, at pp. A29.

- Increase real time visibility of DER operation to enable distribution system operators to maintain safe and reliable operation of the electric system.
- Existing generation interconnection rules related to islanded operation require modification for microgrids to be considered as future grid resiliency solutions. Existing interconnection rules require distributed generating resources to shut off during an outage and only operate during an outage if the generation becomes isolated from the grid.
- Need a more streamlined expedited regulatory approval process for DER interconnections intended to meet electric system needs

The following sections describe the electric services, grouped by the potential role of DERs to provide these services: services that DERs can provide, services that DERs may be able to provide, and services that DERs cannot provide. For purposes of Demo B, DERs were assumed able to defer projects associated with the services that DERs can provide.

## 3.1. Services that DERs Can Provide in Demo B

### 3.1.1. Transmission and Distribution Capacity Deferral

DERs can reduce the thermal loading on all components of the electrical grid. In a radial network, thermal loading is reduced between the DER's location and the location of the existing source(s) of generation as long as overall power flow profiles result in a net reduction. By sufficiently reducing the load on the distribution system, a DER may alleviate the need to modify or construct additional electrical infrastructure and allow existing equipment to serve more loads. To accomplish this, a DER must deliver energy of the need, typically during peak loading times, therein reducing the electrical demand on existing system components. As the cost for the grid's existing capacity has already been realized by customers, the reduction in electrical demand facilitated by a DER does not necessarily result in value for utility customers[26]. In order for the DER to have real value for customers, it must defer a future capital investment(s) at a lower net overall cost. In this case, it must defer an investment needed to increase capacity. If the DER capacity enhancement fails to defer future investment(s) in a reliable and cost effective way, there is no added value for customers in terms of the T&D capacity deferral. However, when a DER does defer a planned utility expenditure, the DER creates added value equal to the time value of money that the utility would have charged customers for the needed capital project. The T&D deferral module developed by E3 in conjunction with the LNBA Working Group will serve as a calculator for these values. For a full explanation of the module please refer to Section 8.

### 3.1.2. Voltage Support

DERs have the capability to provide voltage support in areas on the distribution electric system where additional infrastructure is required to provide customers service delivery voltage required by Rule 2. However, DERs also have the potential to cause voltage excursions above Rule 2 limits when exporting generation on the electric system. DERs will

[26] Chapter 3.2.2 discusses the equipment life extension services that DERs may be able to provide in the future.

not provide voltage support value if DER operation creates voltage excursions itself. Voltage support services are generally substation and/or feeder level voltage management services that are coordinated with utility voltage/reactive power control systems to correct voltage excursions outside Rule 2. Distribution systems that have low voltage concerns may have the ability to gain voltage support though the reduction of load provided by DER. These services can be provided by an individual resource and/or aggregate resources, assuming appropriate visibility and dispatch at a circuit level.

Typically, the utilities mitigate low voltage issues by installing resources at the circuit level capable of injecting/absorbing reactive power [27] (capacitor banks), voltage regulation/boosting equipment (load tap changer, voltage regulators), or by changing the tap position on distribution transformers[28] locally for customers experiencing low voltage. DERs can provide customer benefit if they are able to defer or eliminate a capital investment required for voltage control as long as the DER don't cause any voltage issues themselves.

DERs may potentially provide voltage support for the electric grid in two ways. First, the DER must be able to inject/absorb reactive power (VAR) at the appropriate location(s) as required to mitigate the voltage need that would otherwise require an upgrade to the distribution system. One method to accomplish this is proper utilization of smart inverters. Second, DERs could reduce the net load at the appropriate locations and therein decrease the voltage drop on the affected sections of the distribution system[29].

For the purposes of Demo B, the value of the voltage support service is directly determined by the deferral value of a planned voltage support project. As with deferred capacity projects, the deferral value is driven by the time value of money realized by deferring an investment. In the absence of planned investment, there are no avoided costs, and thus no value to providing a voltage service. More specifically, as long as voltage remains within the Rule 2 limits there is no need for voltage support and therefore no value in providing additional voltage support equipment. In the future, DERs may support conservation voltage reduction (CVR) strategies if increased visibility and control is made available. With CVR still in conceptual study stages and CVR benefits and assumptions not clearly analyzed for LNBA tool implementation, Demo B voltage support projects did not include CVR benefits.

In Demo B, voltage support project deferral requirements are expressed in terms of load reduction rather than reactive power injection or absorption. The LNBA does not currently have the capabilities to receive the reactive power need as an input. This could be a future enhancement to the LNBA calculation once inverter technology can be leveraged to provide

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[27] Reactive Power is in the unit of Volt-ampere reactive power (VAR). Supplying VARs to an alternating current electric system will increase the voltage while absorbing VARs will reduce voltage. VARs measure the lead or lag between synchronization of voltage and current.

[28] Some distribution transformers have the capability to increase or decrease output voltage on the secondary side of the transformers that serve customers. "Tapping" the distribution transformer refers to increasing or decreasing the voltage output on the secondary side of the transformer.

[29] The voltage level on a distribution feeder decreases as the feeder serves customers further away from the substation and as load increases. Reducing load with DER will counteract the voltage drops on the distribution feeder due to the increasing load.

VARs to meet distribution needs. Supplying the voltage support need in terms of load reduction also provides non-inverter-based DER technologies, such as energy efficiency, to be evaluated as DER solutions to defer voltage support projects.

### 3.1.3. Reliability - Back-tie

The back-tie service creates value by deferring the installation or upgrade of a back-tie switch and associated circuitry. This is used to improve restoration of service by providing an alternative path of supply under abnormal grid conditions. In order to ensure reliable service within a distribution system, it is desirable to have a back-up tie installed such that it can be used to transfer the load from the faulted feeder to an adjacent feeder with available capacity. However, the capacity of a tie switch and attached conductors may be limited and may not be sufficient to accommodate the additional power required on the faulted feeder. One traditional method to resolve the limited capacity is to employ higher rated infrastructure (e.g. larger size electrical equipment including switches and conductors, increased capacity of the tie circuit, and new lines). DERs can provide customer benefit if they are able to defer or eliminate a future capital investment required to increase back-tie capacity at the appropriate locations.

The DER alternative would include installing dispatchable DERs at the appropriate locations to enable rerouting of power, therein reducing the load to be transferred at the time required in the event that the transfer switch is closed. The load reduction would be such that an existing (lesser rated) tie would be able to feed some greater amount of load. Similar to the other T&D deferral services, the value of this service would be equal to the time value of money that would have been spent on a project to improve the rating of the tie to achieve an equal transfer capability with the DERs installed.

### 3.1.4. Resiliency via Microgrid

Resiliency services, as defined in the competitive solicitation framework working group[30], are load modifying or supply services capable of improving local distribution reliability and/or resiliency. This service will provide power to islanded customers through local generation when central power is unavailable during outages. As referenced in the previous section, utilities usually design their distribution systems such that all circuits have ties to adjacent circuits in order to provide another source. The potential of an alternative power source allows system operators to transfer load from one circuit to another in the event of a maintenance outage or unplanned outage.

A microgrid project would serve as an alternative to installation or upgrade of back-ties. The existing LNBA tool does not place a benefit on reliability, so for the purposes of Demo B, the benefit of a microgrid project is related to the deferral or elimination of a traditional back-tie upgrade. During an outage, microgrids are designed to continue service in the event of both distribution circuit and larger system outages (e.g., a substation or transmission line

[30] Competitive Solicitation Framework Working Group Final Report Filed by Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-M), San Diego Gas & Electric Company (U 902-E), and Southern California Gas Company (U 904-G), Aug 1, 2016

outage). However, because substation and transmission outages are rare, the minor increase in reliability brought about by microgrids may not justify their added cost alone. DERs could potentially provide a local microgrid service, consisting of several DERs that feed customers until normal grid service is restored

Additional considerations such as interconnection requirements and advancements in communication, monitoring, and control are required for DER to provide microgrid services. For safety reasons, existing interconnection rules do not allow distributed generation to island SCE distribution circuity. Future technology enhancements must enable increased visibility and communication between DER and grid devices ensuring DERs do not supply power to a faulted location. This is a critical safety concern for the public as well as field crews troubleshooting and detecting the faulted location. Depending on the ownership structure and customers' involvement, the safety, integrity and duration of the service become critical challenges that require in-depth investigation.

## 3.2. Services that DERs Cannot Provide in Demo B but May Provide in the Future

This section addresses the services that DERs have the potential to provide, but are not expressly included in Demo B. Currently, these services are categorized here due to insufficient information (e.g. equipment life extension), insufficient control infrastructure (e.g. Volt/VAR optimization), or regulatory process challenges (e.g. ancillary services) that is required to ensure DER capability to reliability and safely deliver them.

### 3.2.1. Conservation Voltage Reduction (CVR) and Volt/VAR Optimization (VVO)

The IOUs were directed to "include opportunities for conservation voltage reduction and Volt/VAR optimization."[31] CVR refers to the practice to maintain the distribution voltage levels at the lower-end of the acceptable voltage ranges as specified in SCE's Rule 2 (such as between 114 V and 120 V while maintaining 114 V minimum at the customer's meter) in order to achieve energy saving. Studies have shown that doing so can reduce the electrical consumption of certain customer end use devices without a noticeable change in performance. CVR is often a byproduct of VVO, a process to optimally manage voltage and reactive power to reduce system losses, peak demand and/or energy consumption so as to achieve more efficient gird operation.

The actual savings that can be achieved in CVR and/or VVO highly depend on a variety of feeder-specific factors including but not limited to feeder configuration, voltage regulation control, customer end use devices and DER penetration. There has been some benchmarking to quantify the savings but the results vary significantly from system to system. More importantly, most of these did not include many DERs. As DERs will interact with voltage regulation and control devices, the presence of DER in the system brings

[31] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, May 2, 2016, at pp. 30

additional challenges for accurately evaluating the benefits of CVR and/or VVO. The IEEE Guidelines for Implementation and Verification of Conservation Voltage Reduction (IEEE P1885) is an ongoing effort to develop a consistent methodology framework to evaluate the savings achieved by CVR.

Due to the uncertainties listed previously, SCE needs to perform detailed engineering analysis and field research which involve extensive testing over an extended period of time in order to accurately evaluate the benefit of CVR and/or VVO in its own system[32]. In addition, necessary communications and controls will be required to enable the functionalities and full benefits of the program. Therefore, CVR and VVO are not currently estimated or otherwise included in Demo B LNBA values.

### 3.2.2. Equipment Life Extension

Equipment Life Extension is the assumption that DERs may extend the lifespan of existing distribution equipment. Specifically, the reduction in thermal stress by DERs reducing loading on specific equipment may extend the life of electrical insulation (e.g., cable jacketing or transformer oil/paper winding insulation) which in turn may lead to longer electrical equipment lifetimes. Further studies are required to fully understand the correlations between loading and equipment life prior to including this component as a DER service. Therefore, equipment life extension is not currently estimated or otherwise included in Demo B LNBA values.

Currently, the correlation between thermal stress and insulation lifespan are not sufficiently characterized nor are adequate studies available to support needed conclusions, making it difficult to accurately quantify the potential role of DERs in extending equipment life for varying existing vintages of equipment. Furthermore, at present, electrical equipment that is replaced due to aging infrastructure reasons include multiple drivers beyond capacity (e.g. service upgrades) such as visual inspection (e.g. corrosion, damage, bad connections), and obsolete technology (e.g., modernized relays to support new protection schemes). Equipment is strategically replaced due to age and expected failure, as determined through a health index assessment, of which loading is one of multiple drivers.

### 3.2.3. Security Risk Mitigation

Using local DERs to supply critical customer loads reduces the reliance on the central grid and, if upgrades to communications and monitoring systems allow correct operation, may lead to a more robust grid. A current security risk that comes with central grid reliance is low probability, high impact events affecting large numbers of customers. Local DERs may mitigate some of the potential losses and serve to reduce security risks associated with larger assets. This reduced security risk could be a significant societal benefit created by the aggregation of mass deployment of DER.[33]

[32] SCE's Integrated Grid Project has a component to investigate how inverters from variable generation and storage devices can be integrated into the centralized volt/VAR algorithm to respond more quickly to voltage variations caused by high penetrations of DER and still maintain the proper circuit voltage profile.

[33] Evaluation Framework and Tools for Distributed Energy Resources, February 2003.

However, to date, there are no known efforts to objectively quantify the decreased security risks or societal gains associated with DERs supplying critical loads as opposed to a conventional central power plant. Therefore, security risk mitigation is not currently estimated or otherwise included in Demo B LNBA values.

### 3.2.4. Ancillary Services

Ancillary Services help maintain grid stability and reliability. These services include frequency regulation[34], spinning reserve[35], and non-spinning reserve[36]. Some DER technologies can provide these services while some DER technologies may actually increase the requirements for these services. For example, energy storage connected to the bulk power system can increase the available reserves on the system without decreasing conventional generators' efficiency, while most renewable DERs such as PV can increase the system's spinning reserve requirements under certain scenarios like cloud cover[37].

The CAISO operates the only existing market for ancillary services and is working to create a program to allow smaller DERs access to the CAISO ancillary services market[38]. As the CAISO will be the main solicitor for these services, SCE will rely on the CAISO to further develop the market for DERs and to define the requirements for DERs to deliver these services without inadvertently causing distribution system reliability issues. With the currently available market history established through CAISO, there is not sufficient data to assess whether certain DER technologies can effectively deliver these services and determine the actual costs and benefits for these services. As a result, potential ancillary services that DERs can provide is not an electric service considered for Demo B.

### 3.2.5. Power Quality

Power quality is "the concept of powering and grounding electronic equipment in a manner that is suitable to the operation of that equipment and compatible with the premise wiring system and other connected equipment"[39]. So simply put, power quality measures the performance of power system, which covers not only voltage (such as voltage sags, swells, and flicker) but also frequency and waveform (such as harmonics).

With proper coordination between DERs and the grid, DERs can provide uninterrupted service during the loss of central grid services and provide the ability to ride through short-term interruptions. However, some of these benefits will require advanced functions or

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[34] Certified resources providing frequency regulation respond to automatic control signals to increase or decrease their operating levels to maintain the system frequency very narrowly around 60 hertz.
[35] Spinning Reserve is the on-line reserve capacity synchronized to the grid system, ready to meet electric demand within 10 minutes of a dispatch instruction by the ISO
[36] Non-Spinning Reserve is off-line generation capacity that can be ramped to capacity and synchronized to the grid within 10 minutes of a dispatch instruction by the ISO.
[37] If there are a lot of PV installed within a small area, cloud passing could result in PV output in the system drops rapidly.
[38] CAISO Distributed Energy Resource Provider program https://www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx
[39] Institute of Electrical and Electronics Engineers (IEEE) 100 Authoritative Dictionary of IEEE Standard Terms

features such as dynamic reactive current support[40], which will not be available in the near future. In addition, DERs can also negatively impact the power quality. For example, if DERs trip offline during voltage sage events, it will further drive the voltage down; the presence of DERs may also lead to temporary overvoltage, rapid voltage changes, and harmonic distortion.

As discussed, DERs may have both a positive and a negative impact on power quality issues. The evaluation of these impacts usually requires very detailed studies on a case by case basis. In addition, some functionalities that are required to provide power quality services are under development and will not be available until a later time. Therefore, power quality is not currently estimated in Demo B LNBA values.

## 3.3. Services that DERs Cannot Provide

This section highlights electric services that are considered non-deferrable.

### 3.3.1. Repair or Replacement

This category specifically references the repair or replacement of equipment that has been identified as damaged, corroded, broken, leaking, deteriorated, or any other designation identifying a component as impaired in some way that compromises the continued safe operation of the electric system. Equipment in this category can vary from an entire wooden distribution pole to a component in an underground structure. The equipment identified in this category has an existing condition that needs to be rectified.

These services were deemed not available to be provided by DER because these pieces of equipment need to be in good operating condition in order to transfer power from source to end use customer. DERs cannot replace damaged equipment required for the transfer power across the electric system. Both DER and end use customers require distribution system equipment to operate reliably in order to generate energy and consume energy. If damaged equipment is not replaced or repaired, there is an increased probability of the identified component failing causing an outage for both customers consuming and producing power.

### 3.3.2. Reliability (Non-Capacity Related)

Section 3.1 detailed reliability improvements that DERs can provide. However, additional investments may be required to enable those services as well as other utility costs exist that improve reliability that are not capacity related. The reliability (back-tie) and resiliency (microgrid) services that can be provided by DER may need additional investments in order to provide those services.

Installing sectionalizing equipment, such as switches, will enable the ability to transfer to the back-tie circuit or operate a microgrid at desired locations. DERs have the ability to serve load during outage conditions, but they do not provide the sectionalizing capability to

[40] Dynamic reactive current support function deploys volt-VAR management during short-duration abnormally low or high voltage events to support the grid until the voltage returns within its normal range

transfer or isolate customers from the faulted location. Sensing equipment is also required to provide visibility to system operators to optimally transfer load and DERs as well as locate the faulted condition to ensure safe grid operation. Circuit breakers and other distribution line fault detection are required to detect fault conditions and operate accordingly to ensure the safety of the public. DERs do not provide these protection services such as detecting or isolating faults when they occur.

Reliability projects usually require sectionalizing and sensing equipment, regardless if DER is included in the solution, to enable the transfer of customers from a faulted distribution circuit to be served from a different source. In addition, reliability projects also cover fixing standards violations that can involve structural standards such as too much equipment in an underground structure or on a distribution pole. DERs do not provide a service that would fix these structural standards violations.

### 3.3.3. Operations and Maintenance

Maintenance is required to continue the healthy operation of equipment. Operations and Maintenance costs will exist regardless of DERs installed on a distribution network, as long as customers require power delivery through the electrical grid. There is no mechanism for DERs to defer the need to maintain existing equipment. Examples of work in this category include equipment testing, scheduled equipment/structural inspections, and vegetation management.

### 3.3.4. Emergency Preparation and Response

The utility's ability to restore service after outages is not assisted by DERs. These projects often require equipment installation in preparation for an emergency, the replacement of damaged equipment during/after an emergency, or strategies to dispatch service personnel more efficiently. These projects need to be designed and activated in a very short time frame, and simply cannot be met through installing DER on the grid. As such, costs associated with improving emergency response are not avoidable by installing DERs. However, installing an increased amount of reliability back–tie DER services has the potential to provide service to an increased amount of customers while damaged equipment is being replaced.

### 3.3.5. New Business/Work at the Request of Others

These projects entail the installation of necessary infrastructure to serve new customers. If there is a lack of existing infrastructure, new customers cannot consume or produce energy. DERs do not mitigate the need to connect new customers to the grid. For example, if a new business requiring electrical service builds a new facility, a primary distribution line extension may be required along with a distribution transformer and a service conductor to the facilities panel. This equipment is required for the customer to receive power from the electrical grid whether from centralized power or DER not located behind the customer's electrical meter.

## 4. Selected Planning Areas

### 4.1. General Description

In SCE's DRP, the DPA for Demo B was proposed to be selected from its service territory in Orange County, California[41] because this region was identified as an area with ongoing grid modernization and DER integration activities.[42]

However, the Section 4 (LNBA Methodology and Demonstration Project B) of Attachment A of the ACR[43] included expanded requirements for Demo B. The original location no longer fulfilled the Demo B requirements, and therefore, SCE instead selected the Rector Sub-transmission system that meets the modified requirements, including:

- One near term infrastructure project (0-3 years lead time)
- One longer term infrastructure project (3 or more years lead time)
- One of the following criteria:
  - – Voltage support / power quality project
  - – Reliability / resiliency improvement related project
- One (or more) capacity related project

SCE selected five distribution substations within the Rector Sub-transmission system as its DPA with the following planned projects:

- A capacitor addition project to maintain an efficient power factor on the Laton 12 kV circuit, with a project operating date of June 2017;
- Construct a 66 kV underground subtransmission line tapped off of the existing Goshen-Liberty 66 kV Subtransmission Line to the Liberty Substation to support the continuing load growth in the area, with a project operating date of June 2018;
- A voltage support project at Mascot Substation due to the loss of Liberty-Hanford-Mascot 66 kV Subtransmission Line, with a project operating date of June 2018;
- A distribution substation capacity increase project in conjunction with a new distribution circuit project at Goshen Substation, with a project operating date of June 2019;
- Re-conductor of the Rector-Lourich-Octol-Tipton-Tulare 66 kV Subtransmission Line to increase capacity, with a project operating date of June 2025.

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[41] Application of Southern California Edison Company (U 338-E) for Approval of Its Distribution Resources Plan, July 1, 2015, Chapter 2; Section E.2 – Demonstration and Deployment Area

[42] In addition, SCE intended to leverage two ongoing projects, the Preferred Resources Pilot project and the Integrated Grid Project, to further incorporate data and/or resources from these activities into Demo B. SCE further refined its DPA selection by identifying the area served by two subtransmission substations: Johanna Substation and Santiago Substation. The area served by these substations was directly affected by the closure of the San Onofre Nuclear Generating Station (SONGS). SCE's recent load forecasts indicated the load growth in this area is in excess of 3% per year through the year 2022. Due to these factors, SCE initially identified this region for a DPA for the Demo B project.

[43] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B, May 2, 2016, at pp. 34.

Figure 1 shows the selected DPA (highlighted in blue), which is located in the California Central Valley in SCE's service territory. Table 1 lists the characteristics of the selected DPA.


FIGURE 1 GEOGRAPHIC LOCATION OF RECTOR DPA

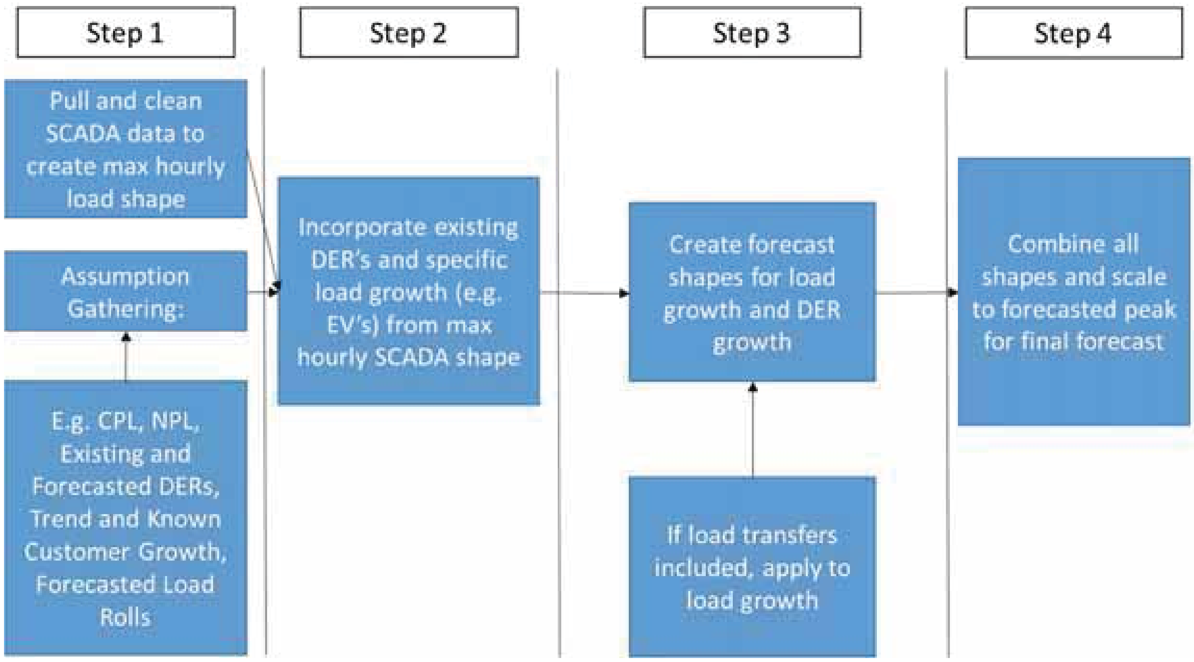
TABLE 1 RECTOR DPA CHARACTERISTICS OVERVIEW

| | Rector DPA |
|---|---|
| Substations | Goshen 66/12, Hanford 66/12, Mascot 66/12, Octol 66/12, Tulare 66/12 |
| Area | Central Valley |
| Service Area Size | 120 $mi^2$ |
| Number of Feeders | 44 |
| Number of Customers | 49,700 |
| 2016 Projected Load | 314 MVA |
| Number of Service transformers | 9,617 |
| Load types | Mixture of residential and commercial, with significant agricultural loads |
| Special Notes: | Load growth driven by drought conditions |

## 4.2. Planning Inputs: Load Profile Development

SCE began with a 10-year base load growth forecast by considering historical growth rates, development plans, and local economic conditions. SCE analyzed historical substation load profiles and historical customer load growth in the geographic regions served by the distribution assets in the Demo B DPA to forecast how demand is expected to change over the next 10 years. In addition, SCE worked with available agricultural, commercial, industrial, and residential development plans to understand projected increases in demand on existing distribution equipment. This projected increase was based on information provided by developers and historical load profiles of the distribution equipment planned to serve the development. Historical growth rates and known development plans were compared to past and present economic conditions to determine if forecast growth should be adjusted to represent existing conditions. The methodology explained below is extremely time consuming and may not be feasible to perform for all distribution circuits and substations with existing tools and software. Advancements in software are required to perform the load profile development explained below for the entire SCE distribution electric system.

Figure 2 illustrates SCE's hourly load and generation forecasting methodology.



[44]

FIGURE 2 SCE HOURLY LOAD FORECASTING METHODOLOGY

### Step One:

The most recent historical year of hourly SCADA data for the circuit or substation is acquired and corrected for abnormal events (e.g., load transfers, outages, and bad data reads). Due

[44] Normal Projected Load (NPL) reflects the expected forecast demand under normal temperature conditions. Criteria Projected Load (CPL) reflects the expected forecast demand under the maximum temperature conditions over a 10-year period.

to changing customer mix over time, the most recent historical year of SCADA data is used to reflect the existing customer mix.

In addition, forecast assumptions are obtained so they can be applied to the corrected historical SCADA data. This information includes but is not limited to DER growth, historical growth, and future customer growth.

### Step Two:

After the historical SCADA shape has been corrected, the existing DER is removed from the historical shape to be forecasted separately from the load. DER would increase at the same rate of load and not at the rate of DER penetration if DER was bundled with the load when developing forecasted shapes. DER and load are separate components of the forecast that increase at different rates. The resultant load shape is estimated to represent the demand being contributed by customer load excluding all DER including electric vehicles and energy storage. This load shape will represent the base shape for the forecasted profiles to be created.

### Step Three:

Once a base shape is determined, forecasted shapes are created for all the DERs and load growth components of the forecast. These shapes are adjusted to the magnitude used in the 10-year forecast.

### Step Four:

Once all the DER and load growth shapes are created, they are combined to create the final forecasted profile. This final profile is then scaled to the peak load projected for the maximum temperature expected over a 10-year period.

Sometimes a circuit constraint can be solved with a no cost permanent load transfer. If permanent load transfers are forecasted before the last forecast year, an extra step is added to the process described above. The load being transferred to or from the circuit is then removed or added to the shape. This new shape now becomes the new base load shape for the years after the load transfer. Steps 2 – 4 in the processes described above are then repeated to create the final shape for the remaining years of the forecast.

## 4.3. Planning Inputs: DER Forecasts

SCE utilized two DER forecasts for Demo B which included (1) the planning forecast developed in the 2015 SCE distribution and subtransmission planning process, and (2) the DRP Scenario 3 very high DER growth forecast. In general, the process that SCE used to create a circuit-level DER forecast is based on an allocation of a system-wide DER forecasts. The DER allocations described in this section were unconstrained by any limitations of the existing distribution grid to accommodate the DERs. Areas with limited integration capacity and high DER potential may preclude development of some of the DERs projected in the forecast, or alternatively may identify areas where additional distribution investment is needed to accommodate DER growth.

### 4.3.1. SCE 2015 Distribution and Subtransmission Planning Forecast

SCE incorporates energy efficiency, electric vehicles and distributed generation into the planning forecast. This information is gathered from a variety of sources and created at a system level to be synthesized to adjust the forecast for each distribution circuit, distribution substation and subtransmission substation. Energy efficiency and distributed generation will impact demand by decreasing the forecast while electric vehicles increase demand.

The energy efficiency component of the DER forecast consists of the CEC Codes and Standards forecast and the SCE program savings based on the CPUC EE Potential Study[45] These two forecasts are combined and applied to the base load forecast to reduce future growth. Similarly, with PV generation, a forecast is developed at a system level and added to the forecast reducing growth on assets that peak in coincidence with SCE's solar PV representative curves. The plug-in electric vehicles (PEV) is forecast is developed at a lower level compared to a system level forecast.[46].

### 4.3.2. DRP Scenario 3: Very High DER Growth Forecast

The system wide forecast for the very high DER growth scenario developed for the DRP included additional categories of DER compared to the SCE 2015 distribution and subtransmission planning forecast. The DRP Final Guidance required SCE to develop three DER growth scenarios and provided criteria for each scenario, which served as the foundation for their development. The DER forecast components included in scenario 3 are solar PV, energy storage, combined heat and power, additional achievable energy efficiency (AAEE), and demand response, and were developed based on the requirements set forth in the DRP to achieve goals such as:

1. Governor's 2030 Energy Policy Goals
2. Zero Net Energy Goals
3. 2030 GHG reductions identified in the Air Resources Board's 2014 Scoping Plan Update
4. Governor's Zero Emission Vehicle Action Plan
5. Commission's 2020 Energy Storage Requirements
6. Commission's Demand Response (DR) Goal of 5% of peak load managed by DR
7. Reduction in the cost and frequency of routine outages
8. Reduction in the cost and improved responsiveness to major or catastrophic events

The system wide forecasts developed for each DER type were then allocated to each distribution circuit internally using representative DER profiles. SCE identified the types of customers who have the greatest economic potential and/or interest in installing DERs, inventoried the dispersal of these customers across SCE's individual distribution circuits, and then allocated the quantity of DERs to distribution circuits in proportion to the amount of customers with DER potential on these circuits. The methods used to develop the DER

[45] 2013 California Energy Efficiency Potential and Goals Study. February 14, 2014.

[46] This can be referenced in SCE's 2018 GRC testimony Exhibit SCE-09, Results of Operations-Vol. 1. SCE 2018 GRC filed September 2016, SCE-09 Results of Operations-Vol. 1 Sales Forecast.

forecasts for solar PV, energy storage, AAEE, demand response, and combined heat and power are the exact same methods as explained in SCE's Distribution Resources Plan filed to the CPUC July 1, 2015[47].

## 4.4. LNBA Tool Input: Annual Hourly (8760) Load Reduction Need

The load profiles input into the LNBA tool were developed using consistent methodologies for all SCE example projects included in Demo B. Two forecasts were developed: (1) SCE's distribution and subtransmission planning scenario and (2) DRP Scenario 3 very high DER growth, where the originally identified planning need was analyzed to determine the amount of load reduction required to defer the traditional capital investment using the DRP Scenario 3 forecast. The annual hourly (8760) load profile input into the LNBA tool represents the amount of load reduction required to meet the identified planning need. The curve displayed in the tool is the portion of the load profile that is above the defined capacity limit of the distribution circuits and/or substations with the projected violation; not the entire forecasted load curve projected for the circuits or substations with the identified planning need. For example, if a subtransmission line project can be deferred through reducing load at a distribution substation, the amount of load reduction required at that substation is represented as a curve within the LNBA tool. If multiple distribution circuits or substations require load reduction to defer the traditional capital upgrade, the curves for each circuit and/or sub were combined to display a single load reduction requirement profile.

The load reduction requirement for each project was developed by analyzing the load profile created for each distribution circuit and substation in the Demo B DPA identified with or contributing to a planning need, as explained in Section 4.2. The peak day was verified for each year of the forecast and selected for each forecasted annual hourly (8760) load profile. The peak load profile was selected to represent the largest amount of load the distribution circuit or substation would be required to serve over a year timeframe. The capacity limit identified to defer the need for the traditional capital investment is then compared to the peak load profile. The result represents the load reduction requirement DERs would need to serve in order to defer the traditional capital investment.

The same peak need load profile was then created for each day during the defined peak period. For example, most of SCE's distribution assets peak during the summer, in this case the peak need profile was generated for each day from June – October. The same peak need load profile is created for each day in the months of June – October while the rest of the year will not display a load reduction requirement profile. This resultant annual hourly (8760) profile was input into the LNBA tool. The intent of using this method is to represent the amount of DER that must be available at any point during the peak time of year (e.g. summer). The resultant profile is not intended to represent that DERs will be required to serve the supplied load profile every day of the summer, just that it must be available for SCE to call on DER to operate during the summer season.

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[47] Application of Southern California Edison Company (U 338-E) for Approval of Its Distribution Resources Plan, July 1, 2015, at pp. 80 - 84

Reasons for providing the annual hourly (8760) profile in this manner has to do with the accuracy of forecast data. It's unrealistic to predict forecasted overloads on distribution circuit and substations on specific days, 10-years into the future, with existing tools. The DERs may only be required to operate several times a year in order to defer the traditional capital investment, however, SCE does not have the tools to accurately forecast exact days in which DERs would be required to operate. SCE believes it is sufficient to provide the seasons in which DERs will need to be available to operate.

## 5. Description of Deferrable Upgrade Projects in Rector DPA

In SCE's distribution planning process, two distribution and substation capacity upgrade projects, three sub-transmission capacity upgrade projects, and two VAR support projects were identified in the Rector DPA. The two distribution and substation capacity upgrade projects included feeder addition and capacitor installation. The three sub-transmission capacity upgrade projects involved new line construction, capacitor bank installation, line reconductoring, and line/bus conversion. The two VAR support projects required the installation of new capacitors.

These seven projects were required to either increase electrical grid capacity or provide voltage support and were generally deferrable by DERs. However, two of the projects were completed during the course of Demo B and were excluded in Demo B study. Since the two projects were completed, there is no longer a need where DERs can provide a potential solution to defer the projects. Thus, the two projects were not included as a deferrable project. These two projects are described as follows:

- **Turner Capacitor Project**

  The Turner 12 kV circuit out of Tulare 66/12 kV Substation serves residential and industrial load in the surrounding community of Tulare. A recent addition of load at an industrial facility increased the load on the Turner circuit to the point that additional capacitance was required in order to maintain an efficient power factor. This project aimed to improve the power factor on the Turner circuit by installing one new 900 kVAR switched overhead capacitor on a wood pole.

- **Octol Substation Project**

  Octol 66/12 kV Substation serves mostly agricultural load in the rural areas of Tulare County. Due to the drought condition, this area has experienced significant increases in agricultural pumping load. Octol Substation and its four 12 kV circuits would exceed their capacity limitations by 2016. The project aimed to increase the substation capacity and install two new 12 kV distribution circuits at Octol Substation. The project scope included replacing the existing transformers with two 28 MVA transformers, rebuilding the high voltage switchrack at Octol Substation and installing the various cable, switches, and automation for the new distribution circuits, in order to serve the increasing load growth in the area.

Table 2 provides a summary of the five projects that can be deferred by DERs, including the operating date and the LNBA results, in both the planning scenario and the very high DER growth scenario. As shown in the table, in a very high potential DER growth case, the additional DER growth may defer some projects beyond the planning horizon considered in Demo B, which is 2025. The following sections describe the detailed project information for these five deferrable upgrade projects and the associated methodologies to identify the needs of DER for deferral.

TABLE 2 PROJECT SUMMARY

| Category | Project Name | Planning Scenario | | Very High DER Growth Scenario | |
|---|---|---|---|---|---|
| | | Operating Date | LNBA Results[48] | Operating Date | LNBA Results |
| Distribution Infrastructure Projects | Goshen Substation Project | 6/1/2019 | $$$ | Project no longer needed in the planning horizon (until 2025) | $ |
| | Laton Circuit Capacitor Project | 6/1/2017 | $$ | 6/1/2017 | $$ |
| Subtransmission Infrastructure Projects | New Rector-Goshen-Liberty 66kV Subtransmission Line | 6/1/2018 | $$$ | Project no longer needed in the planning horizon (until 2025) | $ |
| | Rector-Lourich-Octol-Tipton-Tulare 66 kV Subtransmission Line Reconductor | 6/1/2025 | $$$$ | Project no longer needed in the planning horizon (until 2025) | $ |
| | Mascot Substation 66 kV Capacitor Bank | 6/1/2018 | $$ | Project no longer needed in the planning horizon (until 2025) | $ |

## 5.1. Distribution Infrastructure Projects

The two distribution infrastructure projects identified as potentially deferrable by DERs in Demo B are explained in the following sections below.

### 5.1.1. Goshen Substation Project

Goshen 66/12 kV Substation is located in the census-designated area of Goshen near Visalia in Tulare County, California. Goshen Substation serves mostly agricultural load. Driven by the increases in agricultural pumping load and the upgrades to the Visalia waste water treatment plant, Goshen 66/12 kV Substation and two 12 kV distribution circuits from Goshen Substation and Oak Grove 66/12 kV substation are expected to exceed their capacity limits by 2019.

This project will provide the necessary capacity at Goshen Substation and its distribution circuits to serve the increasing load growth in the area. The project has an operating date of June 2019 and is categorized as a mid-term project in Demo B.

PROJECT IDENTIFICATION:

- Project Name: Goshen Substation Project
- Project Area: San Joaquin Region, Rector System, Goshen Substation
- Program / Project Type: Distribution Substation Plan

[48] $: No T&D deferral value (still has other LNBA components, e.g. energy); $$: T&D deferral value between 0 and 100 $/kW of need; $$$: T&D deferral value between 100 and 500 $/kW of need, $$$$: T&D deferral value greater than 500 $/kW of need. Please refer to Chapter 8 for detailed discussion.

PROJECT DRIVERS:

- Associated existing equipment and location:
  Two 14 MVA transformers and one old 12 kV lattice type switchrack for four existing 12 kV circuits
- Key Driver of Need:
  Load growth in the area has triggered the need for more capacity at Goshen Substation and a new distribution circuit. A capacity increase will allow future growth and will allow future transfers to offload Oak Grove Substation. A new circuit will require a 12 kV switchrack rebuild at Goshen Substation.
- Observed Issues:
  The Planned Loading Limit (PLL) is expected to be exceeded for Goshen Substation, Curtis circuit fed by Goshen Substation and Monson 12 kV circuit supplied by Oak Grove Substation[49].
- Expected Magnitude of Need:
  As the Curtis circuit is supplied by Goshen Substation, any load reduction on the Curtis circuit can also alleviate the need at Goshen Substation. For example, the peak demand need at Goshen Substation is 2.07 MW and the need at Curtis circuit is 0.2 MW in year 2021. If DER supplies 2.07 MW at Goshen Substation or other circuits it supplies, Curtis circuit will still be overloaded. On the other hand, if there is 0.2 MW of DERs on Curtis circuit, the Goshen substation only needs an additional 1.87 MW to eliminate the overload concerns.
  Part of the Monson circuit load is planned to be transferred to the new 12 kV circuit in order to eliminate its overload condition. In order to defer this project, the amount of load that exceeds the PLL of the Monson circuit needs to be supplied by DERs. Since the Monson circuit is supplied by Oak Grove Substation, the load reduction at Goshen Substation or the Curtis circuit cannot offset the need of the Monson circuit, the need at Monson circuit has to be met independently.

  Table 3 to Table 5 list the expected magnitude of the need by year, under the distribution planning scenario at Goshen substation, Curtis circuit and Monson circuit, respectively.

[49] The Monson circuit and Oak Grove Substation are outside of the Demo B DPA. However, in order to defer the Goshen Substation project, the overload on the Monson circuit still needs to be addressed.

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### TABLE 3 EXPECTED MAGNITUDE OF NEED AT GOSHEN SUBSTATION UNDER PLANNING SCENARIO

| Year | Capacity Need (MW) |
|---|---|
| 2019 | 0.77 |
| 2020 | 1.37 |
| 2021 | 2.07 |
| 2022 | 2.67 |
| 2023 | 3.87 |
| 2024 | 4.47 |
| 2025 | 5.17 |

### TABLE 4 EXPECTED MAGNITUDE OF NEED AT CURTIS CIRCUIT UNDER PLANNING SCENARIO

| Year | Capacity Need (MW) |
|---|---|
| 2019 | 0.00 |
| 2020 | 0.00 |
| 2021 | 0.20 |
| 2022 | 0.30 |
| 2023 | 1.10 |
| 2024 | 1.30 |
| 2025 | 1.40 |

### TABLE 5 EXPECTED MAGNITUDE OF NEED AT MONSON CIRCUIT UNDER PLANNING SCENARIO

| Year | Capacity Need (MW) |
|---|---|
| 2019 | 1.92 |
| 2020 | 2.22 |
| 2021 | 2.62 |
| 2022 | 2.82 |
| 2023 | 2.92 |
| 2024 | 3.02 |
| 2025 | 3.12 |

- Expected Timing of Need:
  The expected timing of the need is from March to October. Figure 3 to Figure 5 show the need curve for Goshen substation, Curtis circuit, and Monson circuit, respectively, on the peak day from 2019 to 2025.

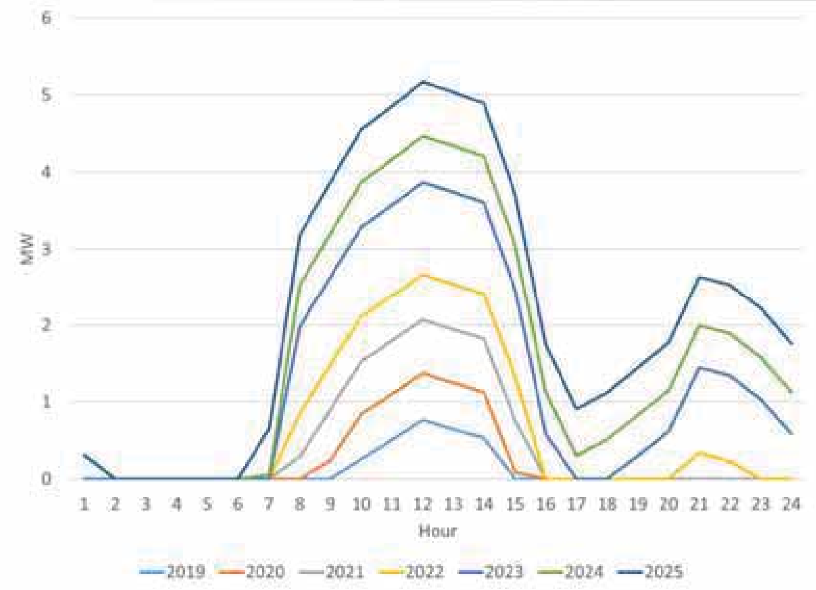


FIGURE 3 NEED CURVE FOR GOSHEN SUBSTATION UNDER PLANNING SCENARIO

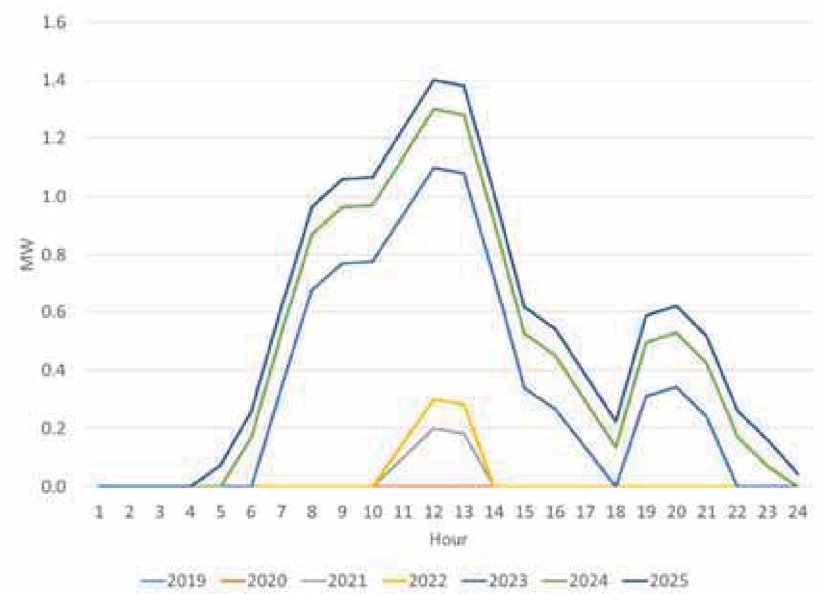


FIGURE 4 NEED CURVE FOR CURTIS CIRCUIT UNDER PLANNING SCENARIO

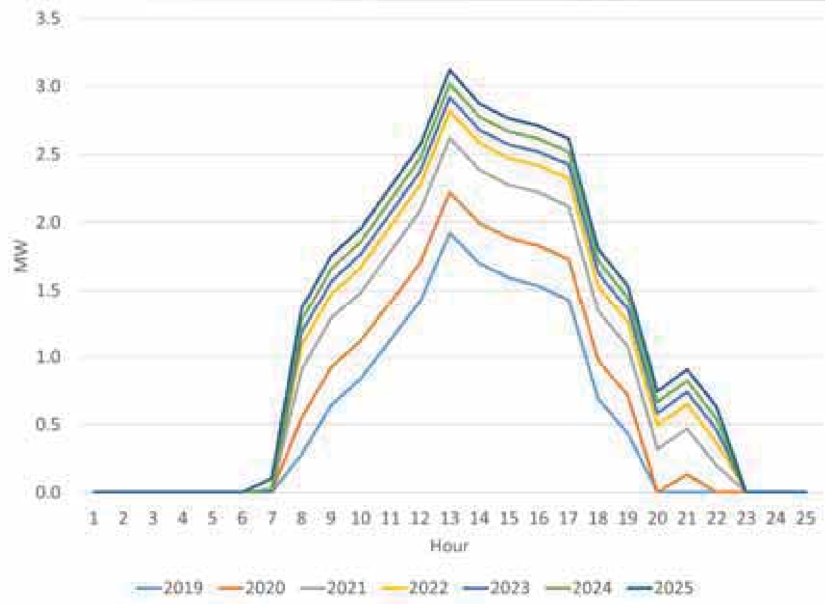


FIGURE 5 NEED CURVE FOR MONSON CIRCUIT UNDER PLANNING SCENARIO

- Known Forecast Uncertainties:
  As part of the load growth is driven by the increased agricultural pumping load due to drought condition. The level of Drought and surface water availability in the next few years will impact the actual load growth. In addition, economic growth factors can also influence the actual load growth in the area.

CONVENTIONAL UPGRADE DESCRIPTION:

- New/Upgraded Equipment and Location:
  Two 28 MVA transformer, one new 12 KV switchrack and one new 12 KV circuit at Goshen Substation
- Associated Load Transfers:
  - Offload Curtis to the new circuit – 1.9 MVA load transfer
  - Offload Harrell to the new circuit – 2.4 MVA load transfer
  - Offload Tagus to the new circuit – 1.7 MVA load transfer
  - Offload Monson to the new circuit – 1.8 MVA load transfer (Goshen Substation to absorb 1.8 MVA from Oak Grove Substation via this transfer)
- Expected Equipment In-Service Date:
  6/1/2019

ELECTRIC SERVICES TO DEFER THE PROJECT:

- Electric Service that DER needs to provide to defer the conventional upgrade:
  Transmission and Distribution capacity deferral
- LNBA results:
  $$$

VERY HIGH DER GROWTH SCENARIO:

Under the very high DER growth scenario published in SCE's DRP, the expected load growth in this area can be offset by the growth of DERs and this project is no longer needed during the study period from 2016 to 2025.

### 5.1.2. Laton Circuit Capacitor Project

The Laton 12 kV circuit out of Hanford 66/12 kV Substation is located in the census-designated area of Hanford in Kings County, California. The Laton circuit serves mostly residential load. The recent construction of new residential tracts has increased the load on the Laton circuit to the point that additional capacitance is required in order to maintain an efficient power factor.

This project will reduce the VAR deficit on Laton from 1700 kVAR to 500 kVAR to improve the power factor and circuit efficiency[50]. The project has an operating date of June 2017 and is categorized as a near-term project in Demo B.

PROJECT IDENTIFICATION:

- Project Name: Laton Circuit Capacitor Project
- Project Area: San Joaquin Region, Rector System, Hanford Substation
- Program / Project Type: Distribution VAR Program

PROJECT DRIVERS:

- Key Driver of Need:
  Load growth in the area has triggered the need for more capacitance on the Laton circuit out of Hanford Substation in order to maintain an efficient power factor. This will require the installation of a new 1200 kVAR overhead capacitor.
- Expected Magnitude of Need:
  As the VAR need is determined by circuit loading, any load reduction on the Laton 12 kV circuit will also alleviate the need for additional capacitors.

TABLE 6 EXPECTED MAGNITUDE OF NEED AT LATON CIRCUIT UNDER PLANNING SCENARIO

| Year | Capacity Need (MW) |
|---|---|
| 2017 | 2.43 |
| 2018 | 2.45 |
| 2019 | 2.48 |
| 2020 | 2.52 |
| 2021 | 2.56 |
| 2022 | 2.60 |
| 2023 | 2.65 |
| 2024 | 2.70 |
| 2025 | 2.75 |

[50] A VAR deficient less than half of the largest acceptable capacitor (e.g.,1200 kVAR) on the feeder does not trigger a capacitor project.

- Expected Timing of Need:
  The expected timing of the need is from May to September. Figure 6 shows the need curve on the peak day, which describes the magnitude of the DER needs at different time of the day, from 2017 to 2025.

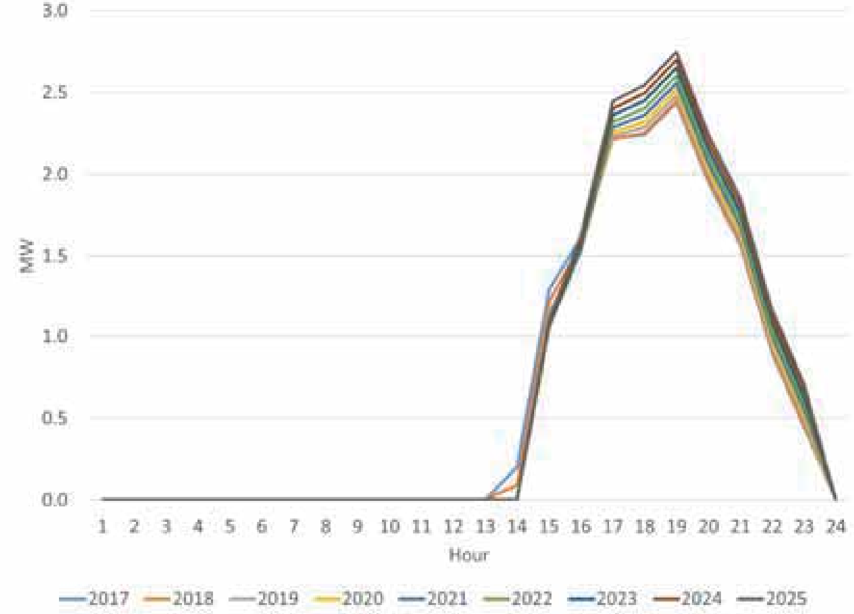


FIGURE 6 NEED CURVE FOR THE LATON CIRCUIT UNDER PLANNING SCENARIO

- Known Forecast Uncertainties:
  As the project is driven by the expected load growth in the area, economic growth factors can influence the actual load growth.

## CONVENTIONAL UPGRADE DESCRIPTION:

- New/Upgraded Equipment and Location:
  One 12 kV 1200 kVAR switched overhead capacitor on existing wood pole 4226842E.
- Associated Load Transfers:
  None
- Expected Equipment In-Service Date:
  6/1/2017

## ELECTRIC SERVICES TO DEFER THE PROJECT:

- Electric Service that DER needs to provide to defer the conventional upgrade:
  Transmission and Distribution capacity deferral
- LNBA results:
  $$

VERY HIGH DER GROWTH SCENARIO:

Under the very high DER growth scenario published in SCE's DRP, the load reduction required in order to alleviate the need for additional capacitors will be reduced, but required during the same time of the day as presented in Table 7.

TABLE 7 EXPECTED MAGNITUDE OF NEED ON THE LATON CIRCUIT UNDER VERY HIGH DER GROWTH

| Year | Capacity Need (MW) |
|---|---|
| 2017 | 2.27 |
| 2018 | 2.22 |
| 2019 | 2.15 |
| 2020 | 2.08 |
| 2021 | 2.01 |
| 2022 | 1.93 |
| 2023 | 1.85 |
| 2024 | 1.76 |
| 2025 | 1.67 |

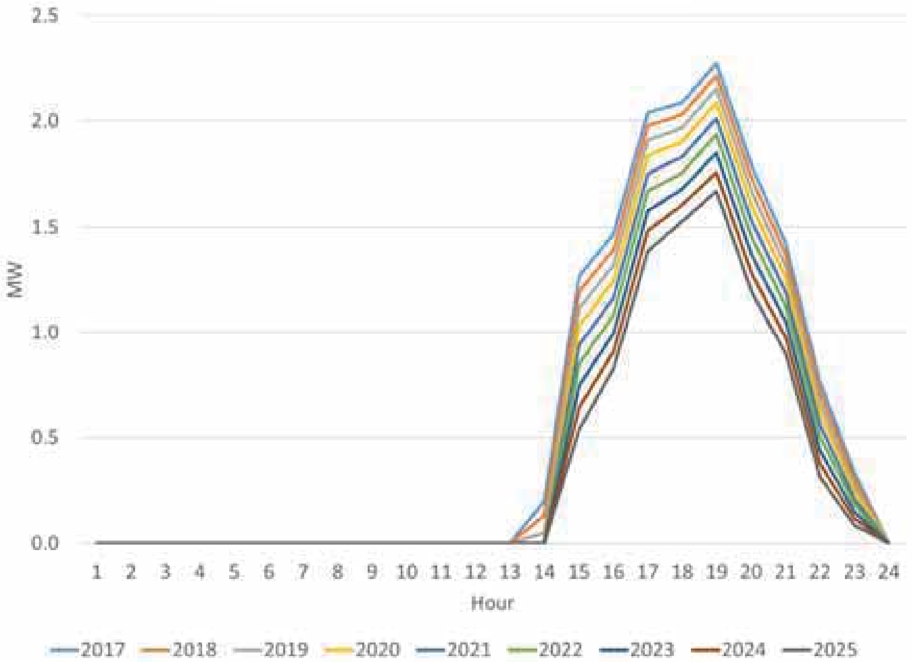


FIGURE 7 NEED CURVE FOR THE LATON CIRCUIT UNDER VERY HIGH DER GROWTH SCENARIO

## 5.2. Subtransmission Infrastructure Projects

Three subtransmission projects were identified as potentially deferrable by DERs in the Demo B project. Due to the network configuration of the subtransmission system versus radial configuration for the distribution system, the methodology for determining the DER need is different from the distribution projects. In systems with network configurations, changes made at one location will likely impact other parts of the system. Sometimes, due to constraints such as space limitation, the proposed solution may include adding or upgrading equipment in adjacent substations. For example, a capacitor bank is planned to be installed in Mascot Substation to address a voltage issue at Hanford Substation (please refer to section 5.2.3 for details). A network system requires a load flow analysis to determine impacts to the entire system when a single modification is made. In systems with radial configurations, changes made on the system only impact the specific circuits that are being modified or involved in a transfer of load. Figure 8 displays a representation of a networked subtransmission system configuration.

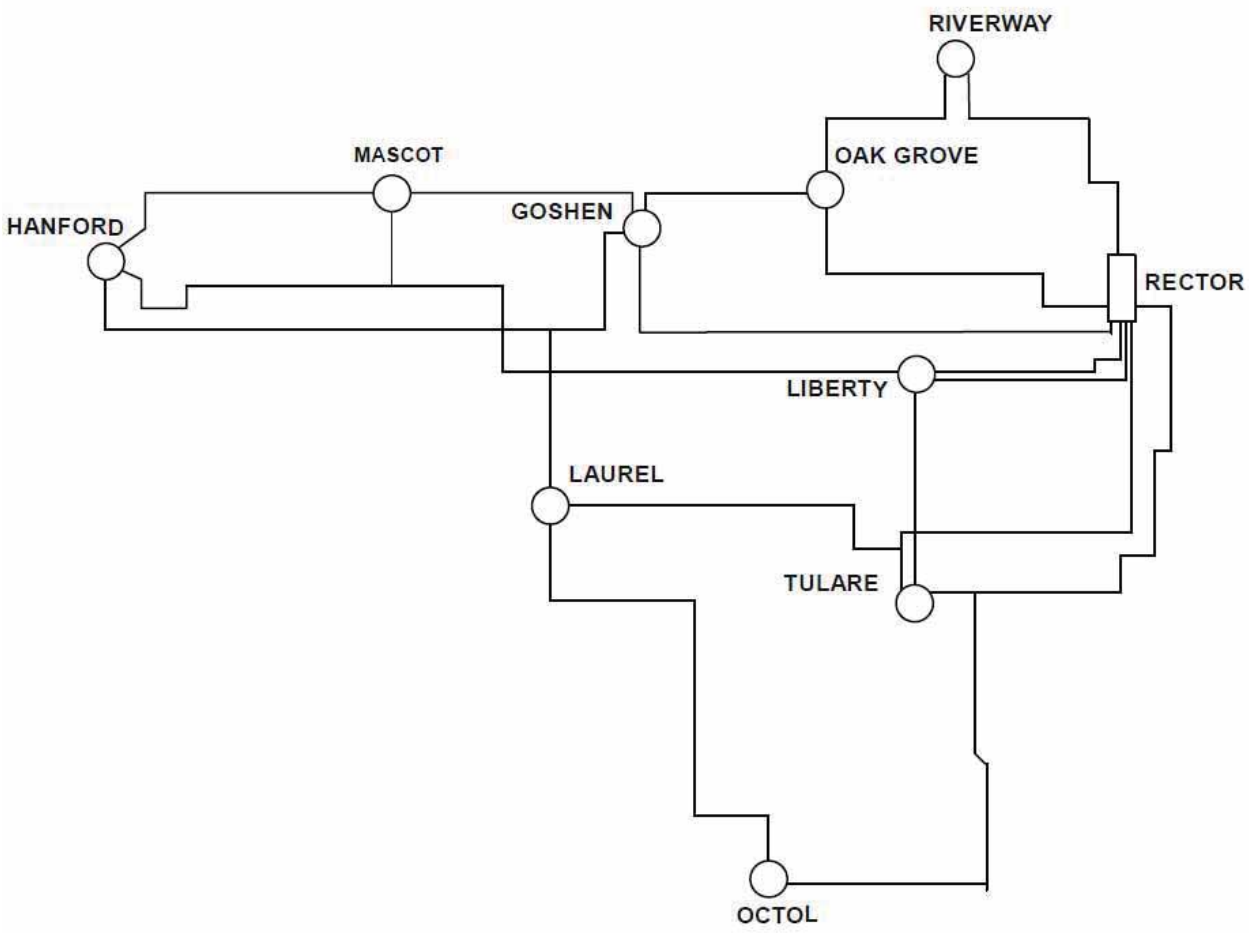


FIGURE 8: REPRESENTATIVE SUBTRANSMISSION LINE NETWORK CONFIGURATION

The purposes of subtransmission projects are to:

- Provide sufficient subtransmission line capacity to maintain subtransmission line loadings within established normal ratings with all lines in service. (base case condition)
- Provide sufficient subtransmission line capacity to maintain subtransmission line loadings within established emergency ratings with one line out of service. (N-1 condition)
- Provide sufficient subtransmission line capacity and/or subtransmission capacitor banks to limit voltage drops at load-serving substations to 5% or less under N-1

conditions and maintain 0.95 per unit (p.u.) voltage and above under base case conditions and N-1 contingency conditions after corrective action has occurred.

During the planning process, SCE performed power flow analysis to determine projected subtransmission line loading under base case and N-1 conditions, as well as voltage drops at load-serving substations under N-1 conditions. If lines were found to be loaded beyond their normal ratings under base case conditions, or beyond their emergency ratings under N-1 conditions, or if N-1 voltage drops exceeding 5% were found at load-serving substations, infrastructure project(s) are evaluated to correct the identified issues. Traditional options include reconductoring existing lines with larger conductor, reconfiguring existing lines, adding new lines, installing subtransmission capacitor banks, or transferring load between substations at the distribution level.

Depending on the nature of the issues, sometimes DERs can serve as an alternative in lieu of the traditional measures to reduce the line loading levels in order to correct the identified problem. Since the voltage drop is determined by the line loading as well, load reduction can also alleviate the voltage problems.

When identifying the amount of DERs needed to defer the planned substransmission projects, studies were performed on all five substations within the Demo B DPA to determine the DER needs for every year of the 2016-2025 planning cycle. The most effective solution (i.e., the solution with the smallest amount of DERs needed) is presented.

Following the standard SCE practice, this study is based on a load forecast under the normal weather, non-coincident peak distribution station load forecasts taken directly from SCE's 2016-2025 Distribution Substation Plan (DSP) for the planning scenario utilizing the DER forecast in the 2016-2025 DSP; and under the normal weather, non-coincident peak distribution station base load forecasts taken directly from the 2016-2025 DSP and combined with the DER forecast under SCE's 2015 DRP very high potential growth case for the very high DER growth scenario. Local generation at the subtransmission level was assumed to be either on-line or off-line, depending on which scenario produced the worst-case line loading in the power flow analyses for both maximum and minimum summer and winter loading scenarios.

### 5.2.1. New Rector-Goshen-Liberty 66kV Subtransmission Line

The Rector-Goshen 66 kV Subtransmission Line serves Goshen Substation in the city of Goshen. The loading on the Rector-Liberty 66 kV No. 1 and Rector-Liberty 66 kV No. 2 subtransmission lines is projected to exceed their capacity limits in 2016, under N-1 line outage conditions, due to continuing load growth in the area.

The main driver for this project is the load growth at Liberty Substation which is outside of the Demo B DPA. Because of the network configuration of the system, there is a flow going from Liberty Substation to both Hanford Substation and Tulare Substation, which are within the Demo B DPA. Reducing the load at Hanford Substation and Tulare Substation can also alleviate the overload issues.

The project has an operating date of June 2018 and is categorized as a near-term project in Demo B. It is to note that due to the time needed for obtaining the permit and construction, the project operating date is in 2018 even though the need arises in 2016. SCE will have to file exceptions but monitor the associated lines closely for necessary actions.

PROJECT IDENTIFICATION:

- Project Name: New Rector-Goshen-Liberty 66 kV Subtransmission Line
- Project Area: San Joaquin Region, Rector System, Liberty 66/12 kV Substation
- Program / Project Type: Subtransmission Lines Program

PROJECT DRIVERS:

- Key Driver of Need:
  Load growth in the area has triggered the need for one more subtransmission line to serve Liberty 66/12 kV Substation
- Location and Overloaded Equipment:
  Rector Substation; Rector-Liberty 66 kV Subtransmission No.1 & 2 Lines
- Expected Magnitude of Need:
-
-
- TABLE 8 lists the expected magnitude of need at Liberty Substation under the planning scenario. From 2018, the capacity need drops from 40.5 MW to 8 MW. The overload magnitude drops significantly in 2018 because the circuit breaker limitations on both the Rector-Liberty No.1 66 kV and Rector-Liberty No.2 66kV Subtransmission Lines are to be cleared by planned projects to replace the circuit breakers on both ends of the lines.

  As previously stated, the study evaluated the opportunities of deferring this project in five substations within Demo B DPA and presented the most effective solution. The amount of needs identified at a specific substation may be higher than the overload magnitude on the substation causing the violation due to the network configuration of the subtransmission systems, especially when the DERs are not directly located at the substation causing the violation.

  Table 9 shows the magnitude of need at Tulare Substation that can defer this project, under the planning scenario. It shows that the amount of DER needed in order to defer the project is as high as 102 MW and 105 MW for 2016 and 2017, respectively. As the project operating date is not until 2018, the LNBA calculation evaluated the needs since 2018.

TABLE 8 EXPECTED MAGNITUDE OF NEED AT LIBERTY SUBSTATION UNDER PLANNING SCENARIO

| Year | Capacity Need (MW) |
|---|---|
| 2016 | 37.1 |
| 2017 | 40.5 |
| 2018 | 8.0 |
| 2019 | 11.0 |
| 2020 | 12.8 |
| 2021 | 14.9 |
| 2022 | 16.4 |
| 2023 | 18.0 |
| 2024 | 20.1 |
| 2025 | 21.8 |

TABLE 9 EXPECTED MAGNITUDE OF NEED AT TULARE SUBSTATION UNDER PLANNING SCENARIO

| Year | Capacity Need (MW) |
|---|---|
| 2016 | 102 |
| 2017 | 105 |
| 2018 | **12** |
| 2019 | **20** |
| 2020 | **27** |
| 2021 | **33** |
| 2022 | **33** |
| 2023 | 39 |
| 2024 | 49 |
| 2025 | 53 |

Starting from 2023, the amount of DERs needed to defer the project becomes larger than Tulare Substation's minimum load, which is around 35 MVA. In other words, if the required amount of DER is interconnected to the system after 2023, reverse power flow will occur at Tulare Substation during light load periods and may adversely impact the system protection scheme, reliability and safety, which will require detailed study for system upgrade solutions. As a result, for the purpose of Demo B, the project can be deferred by sufficient DERs until 2022 within the examined 10-year range.

- Expected Timing of Need:
  The expected timing of the need is from June to September. Figure 9 shows the need curve on the peak day, which describes the magnitude of the DER needs at Tulare

Substation at different time of the day, from 2018 to 2022.

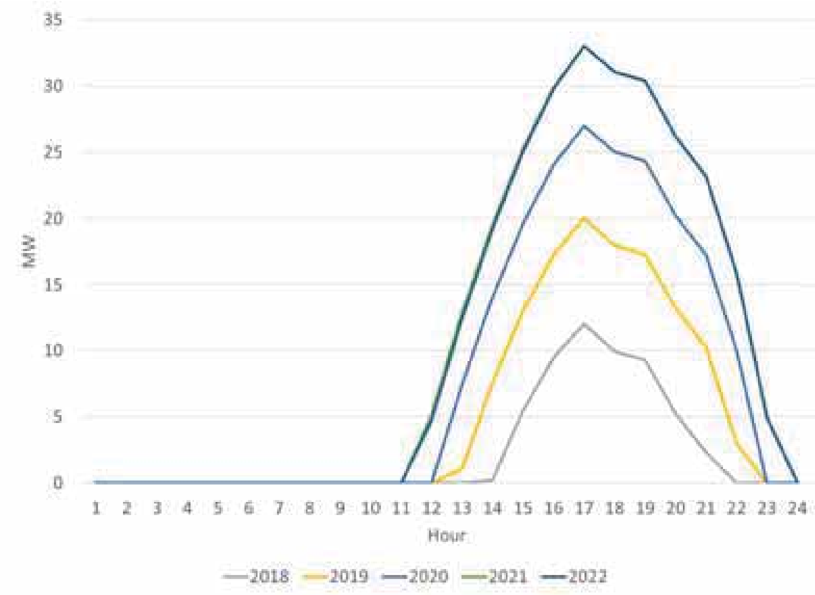


FIGURE 9 NEED CURVE FOR THE TULARE SUBSTATION UNDER PLANNING SCENARIO

- Known Forecast Uncertainties:
  As the project is driven by the expected load growth in the area, economic growth factors can influence the actual load growth.

CONVENTIONAL UPGRADE DESCRIPTION:

- New/Upgraded Equipment and Location:
  New 66 kV source line tapped off of the existing Rector-Goshen 66 kV Line to Liberty Substation.
- Associated Load Transfers:
  None
- Expected Equipment In-Service Date:
  6/1/2018

ELECTRIC SERVICES TO DEFER THE PROJECT:

- Electric Service that DER needs to provide to defer the conventional upgrade:
  Transmission and Distribution capacity deferral
- LNBA results:
  $$$

VERY HIGH DER GROWTH SCENARIO:

As stated previously, due to the time needed for obtaining the permit and construction, this project has an operating date of 2018 even though the need arises in 2016. Under the very high DER growth scenario published in SCE’s DRP, the expected load growth in this area can be offset partially by the growth of DERs and the overload is expected to occur only in 2016 and 2017, as shown in Table 10. However, as shown in Table 11, the amount of DERs needed at Tulare Substation in order to defer this project in these two years is much higher than its substation minimum loading, which will lead to reverse power flow during light loading conditions and will require a detailed study to understand the potential impact. For the purpose of Demo B, the project (with an operating date of 2018) is no longer needed at least until 2025 under the very high DER growth scenario.

TABLE 10 EXPECTED MAGNITUDE OF NEED AT LIBERTY SUBSTATION UNDER VERY HIGH DER GROWTH SCENARIO

| Year | Capacity Need (MW) |
|---|---|
| 2016 | 32.9 |
| 2017 | 33.2 |

TABLE 11 EXPECTED MAGNITUDE OF NEED AT TULARE SUBSTATION UNDER VERY HIGH DER GROWTH SCENARIO

| Year | Capacity Need (MW) |
|---|---|
| 2016 | 88 |
| 2017 | 89 |

### 5.2.2. Rector-Lourich-Octol-Tipton-Tulare 66 kV Subtransmission Line Reconductor

The Rector-Lourich-Octol-Tipton-Tulare 66 kV Subtransmission Line serves Lourich, Octol and Tulare substations in the city of Tulare; and Tipton Substation in the city of Tipton. Due to continuing load growth in the area, particularly Octol Substation, the loading on the Rector-Lourich-Octol-Tipton-Tulare 66 kV Subtransmission Line is projected to exceed capacity limits by 2025 under base case conditions.

The project has an operating date of June 2025 and is categorized as a long-term project in Demo B.

PROJECT IDENTIFICATION:

- Project Name:
  Rector-Lourich-Octol-Tipton-Tulare 66 kV Subtransmission Line Reconductor
- Project Area:
  San Joaquin Region, Rector System, Octol 66/12 kV Substation
- Program / Project Type: Subtransmission Lines Program

PROJECT DRIVERS:

- Key Driver of Need:
  Load growth in Octol Substation has triggered to upgrade the small conductor on this line in order to increase the line capacity.
- Location and Overloaded Equipment:
  Approximately 5.83 miles of 2/0 copper and 4/0 ACSR conductor on the Rector-Lourich-Octol-Tipton-Tulare 66 kV Subtransmission Line

- Expected Magnitude of Need:
  Table 12 lists the expected magnitude of need at Octol Substation under the planning scenario.

TABLE 12 EXPECTED MAGNITUDE OF NEED AT OCTOL SUBSTATION UNDER PLANNING SCENARIO

| Year | Capacity Need (MW) |
|---|---|
| 2025 | 1 |

- Expected Timing of Need:
  The expected timing of the need is from June to September. Figure 10 shows the need curve on the peak day, which describes the magnitude of the DER needs at Octol Substation at different time of the day in 2025.

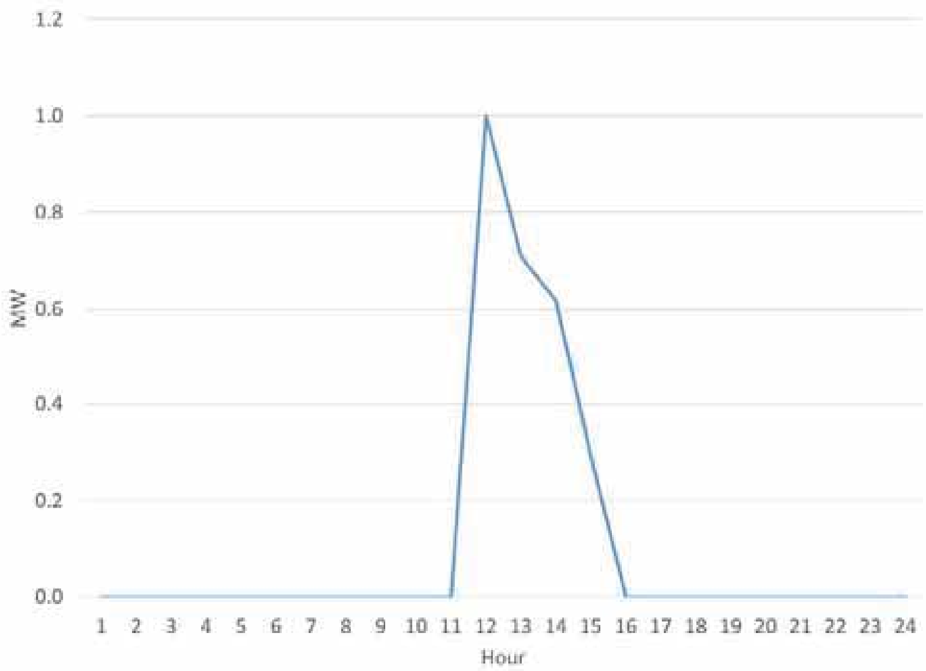


FIGURE 10 NEED CURVE FOR THE OCTOL SUBSTATION UNDER PLANNING SCENARIO

- Known Forecast Uncertainties:
  As the project is driven by the expected load growth in the area, economic growth factors can influence the actual load growth.

CONVENTIONAL UPGRADE DESCRIPTION:

- New/Upgraded Equipment and Location:
  Re-conductor small conductors on the Rector-Lourich-Octol-Tipton-Tulare 66 kV Subtransmission Line with higher capacity rated 954 SAC conductor and convert the exiting five-point line into two-point and four-point lines. In addition, convert the Tulare Substation operating and transfer bus into a double bus, double breaker configuration.

- Associated Load Transfers:
  None
- Expected Equipment In-Service Date:
  6/1/2025

**ELECTRIC SERVICES TO DEFER THE PROJECT:**

- Electric Service that DER needs to provide to defer the conventional upgrade:
  Transmission and Distribution capacity deferral
- LNBA results:
  $$$$

**VERY HIGH DER GROWTH SCENARIO:**

Under the very high DER growth scenario published in SCE's DRP, the expected load growth in this area can be offset by the DER growth and the project is no longer needed by 2025.

### 5.2.3. Mascot Substation 66 kV Capacitor Bank

With the continuing load growth, the 66 kV bus voltage at Hanford Substation is projected to drop in excess of 5% below its nominal level, which is below the minimum acceptable level of 95% of nominal voltage under N-1 line outage conditions (i.e., the loss of the Liberty-Hanford-Mascot Subtransmission Line) by the end of 2018. In addition, the 66 kV bus voltage at Mascot Substation is also projected to fall below 95% of nominal voltage under the same N-1 line outage conditions starting 2019. Due to the space limitation at Hanford Substation, this project will install one 14.4 MVAR, 66 kV switched capacitor bank at Mascot Substation which is located near the city of Hanford.

The project has an operating date of June 2018 and is categorized as a near-term project in Demo B.

**PROJECT IDENTIFICATION:**

- Project Name:
  Mascot Substation 66 kV Capacitor Bank
- Project Area:
  San Joaquin Region, Rector System, Mascot 66/12 kV Substation
- Program / Project Type: Subtransmission Capacitor Program

**PROJECT DRIVERS:**

- Key Driver of Need:
  Load growth in the Hanford substation area has triggered the need for voltage support under the N-1 condition.
- Location and Overloaded Equipment:
  Voltage support is needed at Hanford Substation and Mascot Substation
- Expected Magnitude of Need:

Table 13 lists the expected bus voltage levels at both Hanford and Mascot substations. As voltage drop is determined by loading levels, any load reduction in the area will also alleviate the need for the voltage support.

Even though the project location is at Mascot Substation, the major and earliest need is from Hanford Substation. The most effective location for DERs to defer the project will be at Hanford Substation, as verified by the power flow analyses. Table 14 shows the MW needs to defer the project under the planning scenario.

TABLE 13 EXPECTED BUS VOLTAGE AT HANFORD SUBSTATION AND MASCOT SUBSTATION UNDER PLANNING SCENARIO

| Year | Hanford Substation Bus Voltage (p.u.) | Mascot Substation Bus Voltage (p.u.) |
|---|---|---|
| 2018 | 0.943 | 0.951 |
| 2019 | 0.938 | 0.946 |
| 2020 | 0.934 | 0.946 |
| 2021 | 0.941 | 0.949 |
| 2022 | 0.937 | 0.945 |
| 2023 | 0.934 | 0.942 |
| 2024 | 0.929 | 0.938 |
| 2025 | 0.932 | 0.940 |

TABLE 14 EXPECTED MAGNITUDE OF NEED AT HANFORD SUBSTATION UNDER PLANNING SCENARIO

| Year | Capacity Need (MW) |
|---|---|
| 2018 | 6 |
| 2019 | 2 |
| 2020 | 4 |
| 2021 | 7 |
| 2022 | 10 |
| 2023 | 12 |
| 2024 | 7 |
| 2025 | 13 |

- Expected Timing of Need:
  The expected timing of the need is from June to September. Figure 11 shows the need curve on the peak day, which describes the magnitude of the DER needs at Hanford Substation at different time of the day from 2018 to 2025.

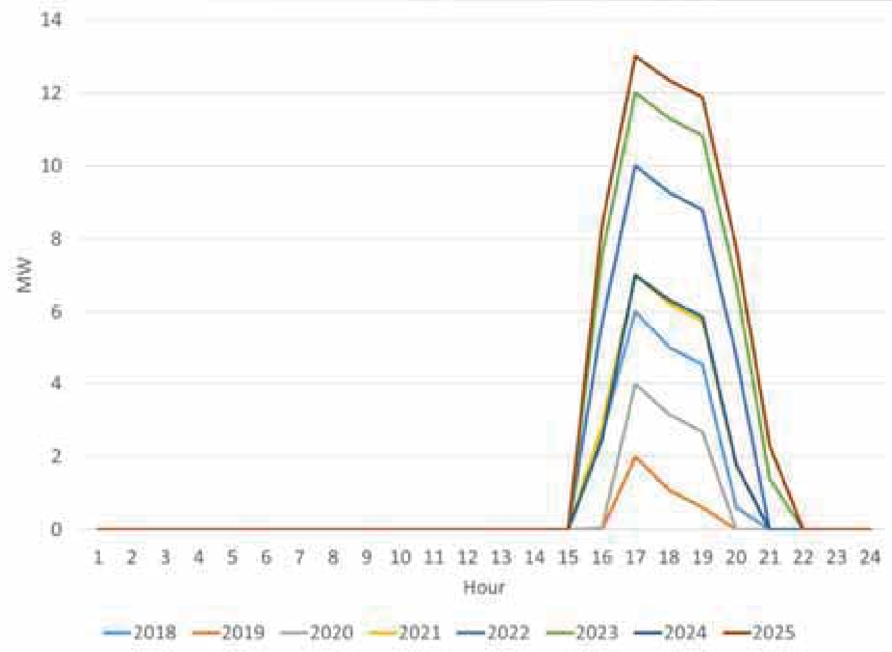


FIGURE 11 NEED CURVE FOR THE HANFORD SUBSTATION UNDER PLANNING SCENARIO

- Known Forecast Uncertainties:
  As the project is driven by the expected load growth in the area, economic growth factors can influence the actual load growth.

CONVENTIONAL UPGRADE DESCRIPTION:

- New/Upgraded Equipment and Location:
  New 14.4 MVAR, 66 kV switched capacitor bank at Mascot Substation.
- Associated Load Transfers:
  None
- Expected Equipment In-Service Date:
  6/1/2018

ELECTRIC SERVICES TO DEFER THE PROJECT:

- Electric Service that DER needs to provide to defer the conventional upgrade:
  Voltage Support
- LNBA results:
  $$

VERY HIGH DER GROWTH SCENARIO:

Under the very high DER growth scenario published in SCE's DRP, the load growth is offset by the DER growth and the project is no longer needed by 2025.

## 6. Description of Operations and Maintenance Work in Rector DPA

Based on SCE's Distribution Inspection and Maintenance Program (DIMP), inspectors perform periodic inspection of distribution assets within timeframes defined by CPUC General Order 165 (GO165), which has established inspection cycles and record keeping requirements for distribution assets. In general, utilities must patrol their systems once per year or once every two years depending on the service territory characteristics. In addition, depending on the type of equipment, detailed inspections of the distribution assets are required every 3-5 years during which the condition of inspected equipment, issues found, and a scheduled date for corrective action must be recorded. The SCE's DIMP program has defined five different inspection categories as follows:

1. Overhead Detail Inspections
2. Underground Detail Inspections
3. Padmounted Detail Inspections
4. Intrusive Wood Pole Inspections
5. Patrols

According to GO165, all issues observed during the inspection phase are documented and prioritized. The prioritization is performed based upon the risk associated with the condition according to a risk matrix contained in SCE's DIMP Manual. High priority repairs have to be completed immediately (high priority), some repairs are to be completed at a later date within two years (medium priority), while some minor repairs can be completed when a future project is scheduled at that location (low priority).

Since the DIMP program is based on distribution assets inspection within specific mandated timeframes and generally address damaged or deteriorated equipment, DERs have very little to no value to maintenance services under this program. All of the notifications identified in this category replace compromised equipment to ensure continued safe operation of the distribution system. These projects enable the ability for both load and DERs to connect to the system and operate reliably and safely. Without these projects the system would operate with compromised equipment providing the risk of outages requiring both load and DER to be de-energized. Deferred maintenance projects will result in a generally unsafe electric system, for example, deteriorated poles could fall in the street, unsafe switches could catastrophically fail resulting in an explosion, and fault conditions could cause prolonged outages impacting critical customers. Therefore, these maintenance repairs are determined to not be deferrable with DERs.

SCE currently has 12,184 maintenance notifications identified in the Demo B DPA as of July 22, 2016. The summary of these notifications is described in this section and the completed list is provided in the downloadable dataset. 11,449 notifications were identified on distribution facilities and 735 were on subtransmission facilities.

### 6.1. Subtransmission Maintenance Notifications Details

Table 15 summarizes the high and medium priority 66 kV system maintenance notifications. Table 16 summarizes the low priority subtransmission maintenance notifications to be completed in the event a higher priority project is scheduled at the same location. Both tables provide breakdowns by notification categories with the largest categories related to damaged and deteriorated equipment.

TABLE 15 HIGH PRIORITY SUBTRANSMISSION MAINTENANCE NOTIFICATIONS

| Category | Number of Notifications |
|---|---|
| Clearance of Wire/Structure Reduced Below Acceptable Limits | 4 |
| Damaged/Broken Equipment | 125 |
| Deteriorated Equipment | 201 |
| Pole Support Needs to be Replaced | 2 |
| Excess Load on and/or Reduced Strength of Pole | 1 |
| Total | 333 |

TABLE 16 LOW PRIORITY SUBTRANSMISSION MAINTENANCE NOTIFICATIONS TO BE COMPLETED WHEN A HIGHER PRIORITY PROJECT IS SCHEDULED AT THE SAME LOCATION

| Category | Number of Notifications |
|---|---|
| Corroded Equipment | 1 |
| Damaged/Broken Equipment | 390 |
| Deteriorated Equipment | 2 |
| Loose Equipment | 1 |
| Missing Components | 8 |
| Total | 402 |

## 6.2. Distribution Circuit Maintenance Notifications

Table 17 summarizes the high and medium priority distribution circuit maintenance notifications. Table 18 summarizes the low priority distribution maintenance notifications to be completed in the event a higher priority project is scheduled at the same location. Both tables provide a breakdown of the notification categories. Similar to the subtransmission maintenance projects, the largest number of maintenance projects for distribution circuits is due to damaged or broken equipment.

TABLE 17 HIGH PRIORITY DISTRIBUTION CIRCUIT MAINTENANCE NOTIFICATOINS

| Category | Number of Notifications |
|---|---|
| Abnormal Voltage | 1 |
| Animal Nest | 3 |
| Clearance of Wire/Structure Reduced below Acceptable Limits | 368 |
| Corroded Equipment | 41 |
| Damaged/Broken Equipment | 316 |
| Debris/Dirt/Water Removal from Underground Structure | 14 |
| Engineering Field Request, to Examine Facilities | 5 |
| Insulator Support Needs to be Replaced | 8 |
| Remove Facilities No Longer Needed | 39 |
| Oil Filled Equipment Leaking | 12 |

| | |
|---|---|
| Leaning Pole | 16 |
| Loose Equipment | 28 |
| Missing Components | 25 |
| Communication Facilities is Damaged and Needs to be Repaired | 4 |
| Overloaded Distribution Transformer | 1 |
| Excess Load on and/or Reduced Strength of Pole | 15 |
| Special Programs to Replace Equipment for Reliability/Safety | 5 |
| Structure Movement | 6 |
| Unauthorized Attachment | 184 |
| Vegetation/Tree | 93 |
| Customer/Communication Facilities Too Close to SCE Facilities | 25 |
| Total | 1,209 |

TABLE 18 LOW PRIORITY DISTRIBUTION CIRCUIT MAINTENANCE NOTIFICATIONS TO BE COMPLETED WHEN A HIGHER PRIORITY PROJECT IS SCHEDULED AT THE SAME LOCATION

| Category | Number of Notifications |
|---|---|
| Animal Nest | 2 |
| Clearance of Wire/Structure Reduced below Acceptable Limits | 847 |
| Corroded Equipment | 28 |
| Damaged/Broken Equipment | 5,987 |
| Debris/Dirt/Water Removal from Underground Structure | 46 |
| Energized Wire in Vault is Exposed to Accidental Touch | 4 |
| Insulator Support Needs to be Replaced | 192 |
| Remove Facilities No Longer Needed | 45 |
| Oil Filled Equipment Leaking | 2 |
| Leaning Pole | 49 |
| Loose Equipment | 517 |
| Missing Components | 2041 |
| Equipment Not Secured in Place | 4 |
| Excess Load on and/or Reduced Strength of Pole | 1 |
| Special Programs to Replace Equipment for Reliability/Safety | 25 |
| Structure Movement | 16 |
| Unauthorized Facilities on Pole | 282 |
| Vegetation/Tree | 146 |
| Customer/Communication Facilities Too Close to SCE Facilities | 1 |
| Minor Work Not Categorized | 5 |
| Total | 10,240 |

Two of the notification categories contained in Table 17, Abnormal Voltage and Overloaded Distribution Transformer, may seem to have the ability to be deferred by DERs. However, for the purposes of Demo B, these notifications have been determined to not be deferrable through DER based on several reasons.

The abnormal voltage notification is related to specific equipment not operating properly, thereby serving customers an inadequate voltage. This notification specifically identifies a distribution transformer that was not serving customers appropriate voltage. DERs are unable to defer this scenario as a new transformer is required to ensure customers are served at a safe voltage level.

The overloaded distribution transformer notification relates to existing customers being served by a distribution transformer consuming energy in an amount that exceeds its capacity limits. In the future, this type of notifications might be considered deferrable through DER if enough data is available to determine a distribution transformer is reaching capacity limits; and if customers connected to that transformer are willing to participate in a DER programs. In addition, the transformer was replaced in October 2016 approximately three months after the notification was created but before Demo B could be completed.

The category in Table 18 labeled “Minor Work Not Categorized” represents low priority notifications that were identified in 2004. The category is not defined because these notifications were created in a previous software system before converting to the existing SAP system SCE uses to document maintenance notifications. The five notifications in the “Minor Work Not Categorized” project category are still open and will not be completed until higher priority projects are scheduled in those locations.

# 7. Description of Reliability Work in Rector DPA

The objective of the SCE's reliability program is to both improve system reliability by replacing distribution circuit infrastructure before it fails, thereby avoiding unplanned outages to our customers, and making circuits more resilient to future failures.

The Worst Circuit Re-habilitation (WCR) program focuses on those circuits that disproportionately contribute to system SAIDI and SAIFI, and those circuits where average customers are receiving relatively lower service reliability. These projects typically take two years to complete based on the identification, scoping, design, and construction cycle. WCR circuits are identified using three years of outage data with an operating date two years out from present (i.e. 2016 and 2017 projects were identified and scoped in 2014 and 2015).

There are 41 reliability improvement projects identified in the Demo B DPA, including seven substation infrastructure replacement (IR) projects and 19 distribution IR projects for 2016 and 15 distribution IR projects for 2017. These projects include but are not limited to oil switch and/or remote control switches replacement, WCR projects, capacitor replacement and plant betterment projects. Table 19 summarizes the reliability project breakdown by categories.

TABLE 19 RELIABILITY PROJECT OVERVIEW

| Project Category | Number of Projects |
|---|---|
| Substation IR | 7 |
| Oil Switch Replacement | 3 |
| Capacitor Replacement | 7 |
| Remote Control Switch Placement | 2 |
| WCR Projects | 5 |
| Plant Betterment | 17 |
| Total | 41 |

The substation IR projects are replacement projects based on health index, which is an analysis of an individual asset's forecasted end of life. This analysis takes into account multiple factors including results from inspections, asset calendar age, probability of failure and risk analysis of consequences and cost benefits. These projects are not driven by capacity, but they may be bundled with capacity projects.

Oil switch replacement projects are commodity replacement program related with aged switches. All three oil switch projects in the Rector DPA were completed prior to May 1, 2016.

Capacitor replacement projects are to remove or replace aged or damaged capacitors. There are seven projects identified in this category, with three projects completed in 2016 and four projects planned for 2017.

Remote control switch projects are to install mid-point or tie switches to enable load transfer in order to reduce the duration of an outage. These projects are reliability driven instead of capacity driven. Both projects in this category were completed before Sep 20, 2016.

### *WCR Projects*

WCR projects are designed to maintain or improve the reliability of those circuits with historically below-average reliability performance. Projects typically begin with identifying each circuit's most risk-significant mainline cable for replacement, and then additional enhancements are identified to improve the overall circuit reliability. These circuit enhancements include equipment such as automation (remote control switches), automatic reclosers, branch line fuses (BLFs) and fault indicators.

- Two of the WCR projects were designed to improve the reliability of the same circuit. These projects installed overhead remote control switches and one underground remote control switch to enable load transfers under faulted conditions. As a part of the distribution automation scheme, this can reduce both the outage frequency and duration, which are measured by SAIFI/SAIDI. The projects also installed ten BLFs to fuse radial sections. With fuses in place, faults downstream of the fuse will not impact the customers that are upstream of the fuse and therefore helps reduce the exposure of customers to faults. Both projects were completed before Jul 18, 2016.
- One WCR project was to replace cable-in-conduit (CIC) based on the issues identified during the radial line testing such as partial discharge or deteriorated concentric neutrals, which are indicators of potential failure due to cable age or damage to insulation/neutrals. This project was completed by Oct 7, 2016.
- One WCR project was to replace three tie pole switches with remote control switches so that the feeders can quickly pick up transferred load to reduce the outage duration. The project also installed fault Indicators that can assist troublemen to identify the faulted location faster and shorten the outage duration. In addition, the project installed 55 BLFs to fuse radial line sections to reduce the exposure of the circuits to future outages. This project was completed by Apr 28, 2016.
- One WCR project is to replace old mainline cables due to a high amount of age-related failures. This project was proposed for completion in 2017.

### *Plant Betterment Projects*

Plant betterment projects are designed to resolve infrastructure issues and criteria violations that aren't covered by SCE's load growth projects.

- Twelve projects in this category were designed to replace or protect small wires by installing fuses to limit the amount of short circuit duty that conductors may experience. The projects are to prevent wire down events that cause outages and expose the SCE workers and the public to possible hazards. There are five projects in the 2016 plan, with four completed before Oct 20, 2016, and seven projects in the 2017 plan.
- One project was designed to upgrade a remote control switch with remote automated recloser for end-of-line protection. This project was proposed for completion in 2017.

- One project is to install a clearing switch in order to comply with SCE operational standards and prevent unnecessary customer outages during substation maintenance work. This project was proposed for completion in 2017.
- One project addresses a design violation by installing a circuit tie (consisting of conduits and new underground cable) to enable the transfer of a large customer to an adjacent circuit if the main line with old underground cable fails or other events lead to the loss of the source to the previous feeder. This project was completed by Sep 28, 2016. Another project is also to reinforce the tie between two circuits to address a similar feeder design violation. This project is proposed for completion in 2017.

One project replaced two miles of overhead conductor bundled with a new circuit construction on the same poles. This project upgraded the conductor size to create additional operational flexibility allowing load to be restored during outages and to allow for future agricultural load growth. Bundling with the new circuit construction on the same poles reduces the cost by preventing duplicate work on overlapping scope. The project was completed by Mar 18, 2016.

# 8. Project Deferral Benefit Calculation

## 8.1. LNBA Tool Deferral Benefit Calculation

In Demo B, DERs are considered able to defer distribution upgrades by reducing load such that they mitigate the problem that is the driving need for a distribution upgrade. The diagram below provides an example of the simple case of a forecasted overload on a distribution facility which would typically require a distribution capacity upgrade.

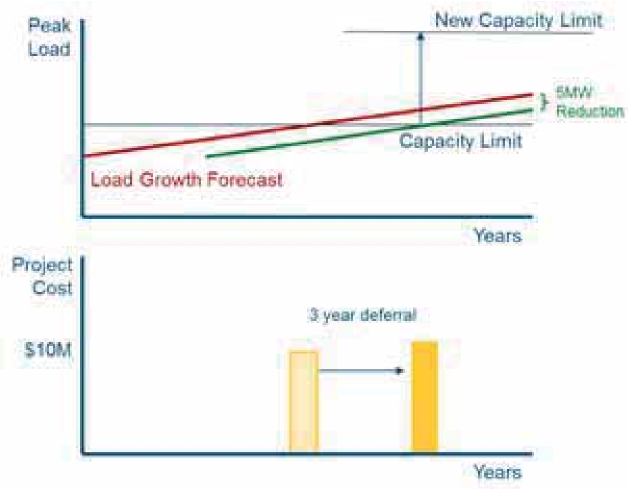


FIGURE 12 PROJECT DEFERRAL EXAMPLE (CREDIT: E3)

The upper chart depicts a DER's ability to delay, for three years, a forecasted overload by reducing peak load by 5 MW. The lower chart depicts the effect of this delay on the timing and quantity of capital investment for the distribution capacity upgrade project which mitigates the overload. Note that the project cost is nominally larger after the three-year deferral due to inflation of material and labor.

The customers' benefit of a deferral is primarily a result of the cost to capitalize such an investment: the present value of raising capital in year 4 instead of year 1. The quantity of this benefit is calculated in Demo B using the Real Economic Carrying Charge (RECC) method, per Commission's direction.[51] In this method, a RECC factor is multiplied by the original upgrade project capital cost to yield the benefit of a one-year deferral. This factor, expressed below, is a function of the utility's cost of capital and the life of the capital asset as well as inflation.

RECC factor:[52]

$$\text{RECC} = \frac{(r-i)}{(1+r)}\left(\frac{(1+r)^N}{(1+r)^N-(1+i)^N}\right) .$$

i=inflation, r=discount rate, N = life of the capital asset

---

[51] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, May 2, 2016, at pp. 30.

[52] This is calculated in the LNBA Tool, Project Inputs & Avoided Costs tab, Row 110.

The RECC factor multiplied by original capital investment does not fully capture all of the customers' savings from a deferral. This is because the actual amount recovered from customers for the original capital investment is always greater than the project cost. The revenue requirement (RRQ) effectively charged to customers includes various other costs such as taxes, franchise fees, utility authorized rate of return, and overheads. These general cost factors are captured in a RRQ Multiplier, which is applied to the product of capital investment and RECC factor. The RRQ Multiplier may vary for different projects, for example, where different types of equipment are treated differently in tax accounting.

Finally, the customer base also avoids any annual O&M activities associated with a new distribution facility as well. Since this is an expense passed to customers as is, it is not multiplied by the RECC factor or the RRQ Multiplier. Since O&M costs are incurred in the year they are performed lifetime O&M is also subject to inflation.

The complete expression of customer benefit associated with a one-year deferral is thus

Deferral Benefit = [original project cost] x [RECC Factor] x [RRQ Multiplier] + [levelized annual O&M]

For a multiple-year deferral, the yearly deferral value beyond the first year are simply discounted to a present value using a discount factor derived from same discount and inflation rates used in the RECC factor.[53]

For the purposes of Demo B, the LNBA results represent the T&D deferral benefit. To obtain the LNBA results, the value of a three-year deferral of the project is divided by the maximum need in kilowatts (kW) during that three-year period. To obtain the final LNBA results, the resulting dollar per kW of need is matched to the corresponding dollar symbol.[54] The table below shows the ranges corresponding to the dollar sign symbol.

TABLE 20 LNBA RESULTS RANGE

| Range ($/kW of need) | LNBA Result |
|---|---|
| 0 | $ |
| >0 to 100 | $$ |
| >100 to 500 | $$$ |
| >500 | $$$$ |

## 8.2. Inputs and Outputs

This section provides an overview of the primary LNBA Tool inputs, outputs and settings related to the deferral benefit calculation. Additional description of these inputs, outputs and settings as well as others are provided in Appendix 2.

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[53] This total deferral benefit is calculated in the LNBA Tool, Project Inputs & Avoided Costs tab, Rows 145-154

[54] In order to preserve market fairness, the actual T&D deferral benefit is not provided to the public.

### 8.2.1. Deferrable Project Inputs

Major inputs related to the deferrable project are summarized below. These are categorized as either Universal Inputs analysis or Project Specific Inputs.

TABLE 21 UNIVERSAL INPUTS

| Name | Location in LNBA Tool | Description | Source (IOU-specific) |
|---|---|---|---|
| Discount Rate | Project Inputs & Avoided Costs; C5 | Used for various financial calculations. | SCE used 10%, its incremental cost of capital, which is intended to be a forward-looking long-term cost of capital[55] |
| RRQ Multiplier | Settings; C13:E28 | Converts capital cost to revenue requirement. | Present value of revenue requirement calculations from a SCE internal model typically used to support analysis for capital approvals and other ad-hoc financial analysis. |
| Equipment Inflation Rate | Settings; F13:H28 | | For T&D, Compound Annual Growth Rate (CAGR) of Handy-Whitman and IHS Global Insight capital escalation rates.<br><br>For IT, CAGR of IHS Global Insight General Plant capital escalation rates. |
| O&M Inflation Rate | Settings; I13:K28 | | For T&D, average of CAGR of SCE labor escalation rates (Based upon average hourly earnings, collective bargaining agreements and IHS Global Insight) and CAGR of IHS Global Insight Transmission and Distribution non-labor O&M escalation rates.<br><br>For IT, CAGR of IHS Global Insight General Plant capital escalation rates. |
| Book Life | Settings; L13:L28 | Used to calculate RECC. | Equipment specific average service life and net salvage used in SCE's 2018 GRC. |
| O&M Factor | Settings, M13:O28 | Used to determine annual O&M savings for associated with a deferral. These are annual O&M for a type of equipment as a percent of its capital cost. | Assumed to be zero as annual O&M is usually associated with ongoing maintenance which cannot be avoided. O&M related to projects were incorporated as an additional adder in the RRQ Multiplier. |

[55] The 10% discount rate is equal to SCE's incremental cost of capital. SCE's incremental cost of capital is intended to be a forward-looking long-term cost of capital, whereas SCE's authorized cost of capital is a short-term cost of capital that largely reflects the cost of existing financing, not new or incremental financing.

TABLE 22 PROJECT-SPECIFIC INPUTS

| Name | Location in LNBA Tool | Description | Source (IOU Specific) |
|---|---|---|---|
| Project Identifiers | Project Inputs & Avoided Costs; Rows 18 and 19 | Used to identify each project. | N/A |
| Equipment Type | Project Inputs & Avoided Costs; Row 20 | Used to select RRQ Multiplier, Book Life, and O&M Factor for a project | N/A |
| Project Cost | Project Inputs & Avoided Costs; Row 27 | Used to calculate deferral benefit. The tool evaluates low (x0.7) and high (x1.5) sensitivities, reflecting uncertainty in the cost estimate. These are derived from cost estimating standards.[56] | Per ACR, each IOU used "existing approaches for estimating costs of required projects." |
| Cumulative MW Reduction Needed | Project Inputs & Avoided Costs; Rows 33-42 | Used to define amount of load reduction needed to achieve deferral. | See Chapter 5 |
| Project Install/Commitment Year | Project Inputs & Avoided Costs; Row 30 | Compared with DER Install Year to check whether a project can be deferred by a DER; also used to evaluate duration of a deferral. | See Chapter 5 |
| Project Flow Factors | Project Inputs & Avoided Costs; Table at C48 | Used to identify upstream projects and the extent to which they're impacted by load reduction at downstream project locations | Projects were calculated individually. |
| Loss Factors | Project Inputs & Avoided Costs; Table at C61 | Used to translate Hourly DER Profile to an actual impact on loading at the location of the problem that causes a deferrable project to exist. | SCE used a system wide value of 1.051 for distribution loss factor obtained from the 2016 LTPP Scenario Tool[57] |
| Load Profile/Need Profile | AreaPeaks; tables at rows 16- | Used to define profile of required DER load reduction to achieve | SCE defined the need profile for each project. See Chapter 5 |

[56] Specifically, the low and high sensitivities reflect a Class 4 estimate as described in the American Association of Cost Estimating recommended practice 17R-97, available at: http://www.aacei.org/toc/toc_17R-97.pdf

[57] Scenario Tool 2016 v1.2. 'Demand Individual Assumptions' tab, cell F186.

| | | | |
|---|---|---|---|
| | 8775 | deferral. | |
| Threshold | AreaPeaks; Row 13 | Defines the threshold above which an overload is assumed to occur in the Load Profile/Need Profile. The hours and magnitude of overload are used to validate whether or not a DER defers a project by mitigating the problem that causes the deferrable project to exist. | Since SCE defined the need profile, threshold is equal to zero. |

### 8.2.2. DER Inputs

Major inputs related to the deferrable project are summarized below. These are the primary inputs that DER providers or stakeholders would use to evaluate various DER alternatives.

TABLE 23 DER INPUTS

| Name | Location in LNBA Tool | Description | Source |
|---|---|---|---|
| DER Location | DER Dashboard, F4 | Used to identify the primary deferrable project which the DER is downstream from. | User Input |
| DER Useful Life | DER Dashboard, F6 | Used to calculate lifecycle avoided costs. | User Input |
| DER Install Year | DER Dashboard, F7 | Used to determine which projects are deferrable and for various avoided cost analyses. | User Input |
| Defer T&D to this year | DER Dashboard, F8 | Used to identify the DER load reduction requirement associated with the deferrable projects upstream of DER Location. If set to 2025, for example, the tool checks whether the Hourly DER Profile is sufficient to mitigate the problem causing upstream deferrable projects to exist in 2024 and prior years. | User Input |
| DER Type | DER Dashboard, K3 | Used to determine renewable integration costs. | User Input |
| Hourly DER Profile | DER Dashboard, F57:F8816 | Hourly load increase/decrease associated with a DER solution. Should be constructed using 2015 calendar and a 1:10 weather year. | User Input |
| Dependability in local Area | DER Dashboard, F5 | Use this to easily scale the DER profile up or down. | User Input |

### 8.2.3. Tool Settings

In addition to inputs, the LNBA Tool has a variety of settings that will determine how certain calculations are made. Major settings and default values are described below.

TABLE 24 TOOL SETTING

| Name | Location in LNBA Tool | Description | Default |
|---|---|---|---|
| T&D Value Basis | DER Dashboard, E13 | "Allocation-based Average vs "Requirement-Based Threshold", "Allocation based average" assigns value even if the peak reduction is insufficient for deferral" | Requirement-based threshold |
| Case to use for allocated hourly costs | Project Inputs and Avoided Costs, C8 | Select whether to use the base cost or the high or low sensitivities. | Base |
| Include or Exclude Deferral Value | DER Dashboard, I24:I33 | Manually include or exclude T&D deferral value associated with deferrable projects upstream of DER Location. Default: Include | Include |
| Include Component | DER Dashboard, D41:D49 | Manually include or exclude LNBA components in LNBA results. | Include |

### 8.2.4. Outputs

The primary LNBA Tool output is the avoided cost associated with the DER solution, which is provided in total as well as broken down by component in the table in the DER Dashboard tab at cell F39. This includes the T&D deferral benefit component, which is provided explicitly at cell H49.

## 8.3. Transmission Benefits

The tool is capable of evaluating a transmission project deferral opportunity in the same way that distribution projects are evaluated in Demo B. The same inputs are required, primarily the timing and cost of a deferrable project and the DER load reduction profile required to achieve that deferral.

The ACR specifically directs the utilities to evaluate the transmission component of LNBA by quantifying the co-benefit value of ensuring that preferred resources relied upon to meet planning requirements in the CAISO's approved 2015-2016 Transmission Plan[58] materialize as assumed. However, the 2015-2016 Transmission Plan does not provide sufficient information to do this analysis. Specifically, it does not identify projects which would be required in the absence of those preferred resources or the associated project costs. It also does not provide information needed to develop DER load reduction requirements.

In lieu of analyzing specific transmission deferral benefits, the LNBA Tool includes a generic system-wide transmission benefit input for users to define.[59] Note that this input is per kW of the DER type that is being analyzed (e.g. per kW of PV). The default transmission value is set to zero, consistent with the default value found in the Public Tool developed in the NEM Successor Tariff Proceeding (R.14-07-002).

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[58] Available on the CAISO Website at: http://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf
[59] Located in the LNBA Tool's DER Dashboard tab at cell K6

SCE anticipates a significant amount of effort to refine this simplified approach in the future, enabling a more detailed treatment of transmission benefits similar to the detailed analysis of distribution benefits in Demo B.

# 9. Other LNBA Components Calculation

As indicated in the Section 2.3, the system-level avoided cost module calculates the benefits of system wide components. These components include avoided energy, avoided generation capacity, avoided GHG, avoided RPS, avoided ancillary services, renewable integration cost adder, and societal and public safety.

## 9.1. Sources

The avoided cost calculator version 1.0[60] [61], a revised distributed energy resources avoided cost model ("DERAC"), was used to derive avoided energy, system avoided generation capacity, avoided GHG, avoided RPS, and avoided ancillary services. For each component sourced from the avoided cost calculator, an hourly profile is provided for 31 years (2016-2047) in the 'SystemAC' tab of the LNBA tool.

The source for the renewable integration cost adder is the interim value adopted in 2014 from D.14-11-042[62].

## 9.2. User Inputs in 'DER Dashboard' Tab of LNBA Tool

In order for the system-level avoided cost module to properly calculate the value of the components, the user needs to provide basic DER information, benefits that the DER can obtain, and a DER hourly profile. A user will need to input these pieces of information in the 'DER Dashboard' tab of the LNBA tool. These inputs will need to be defined in three sections of the 'DER Dashboard' tab: 'DER Settings and Full Local T&D Avoided Cost', 'DER Avoided Costs', 'DER Hourly Shape and Calculations'.

### 9.2.1. 'DER Settings and Full Local T&D Avoided Cost' Section

In the 'DER Settings and Full Local T&D Avoided Cost' section (Row 1) of the 'DER Dashboard' tab, the user will need to select the DER location and DER type. In addition, the user will need to define the dependability in the local area, DER useful life, DER install year, last year of deferral, transmission avoided cost, and local RA multiplier. See Figure 13 for an example the 'DER Settings and Full Local T&D Avoided Cost' section.

| DER Settings and Full Local T&D Avoided Cost | | | | | Version 2.10 |
|---|---|---|---|---|---|
| DER Location and Annual Inputs | | | DER Type | WIND | |
| DER Location | Circuit 1107 | | Integration cost adder ($/MWh) | $ 4.00 | |
| Dependability in local area (eg.g: 90%) | 90% | | | | |
| DER Useful Life (yrs) | 20 | | Transmission Avoided Cost ($/kW of DER) | $0.00 | (Default = 0) |
| DER install year | 2017 | InstallYr | Generation Capacity LCR Multiplier | 1.5 | (Default = 1.0) |
| Defer T&D to this year (Max 2026) | 2026 | | | | |

FIGURE 13 'DER SETTINGS AND FULL LOCAL T&D AVOIDED COST' SECTION

[60] Avoided Cost Calculator v1, available at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=12509
[61] The use of the avoided cost calculator as the source for avoided energy, system capacity, GHG, RPS, and ancillary services costs provides an estimation of those components based on publicly available data.
[62] Decision Conditionally Accepting 2014 Renewables Portfolio Standard Procurement Plans and an Off-Year Supplement to 2013 Integrated Resource Plan, November, 24, 2014, pp. 61-63.

### 9.2.2. ‘DER Impact on Local T&D’ Section

In the ‘DER Impact on Local T&D’ section (Row 11), the user selects the T&D value basis and the components to include in the calculation. Under the dropdown menu of the T&D value basis, there are two options: requirement-based threshold and allocation based average. By selecting the requirement-based threshold option, the DER hourly profile must be able to meet the project need in order to obtain the T&D benefit. By selecting the allocation based average option, the DER hourly profile does not need to meet the project need in order to obtain some T&D benefit. In short, the T&D value basis dropdown allows the user to select whether or not the DER solution receives partial T&D value when that solution does not meet the project needs.

### 9.2.3. ‘DER Avoided Costs’ Section

The ‘DER Avoided Cost’ section (Row 37) contains two areas. In the ‘Include Component?’ area, the user can select whether or not the DER solution will receive the benefit of each component. Under the ‘Lifecycle Value from DER by Component ($)’ area, the ‘DER Avoided Costs’ section provides outputs of total value ($) of the DER solution by component for the contracted life. Figure 14 shows an example of the ‘DER Avoided Costs’ section.

**DER Avoided Costs**

| Include Component? | |
|---|---|
| Energy | TRUE |
| Gen Capacity | TRUE |
| Ancillary Services | TRUE |
| CO2 | TRUE |
| RPS | TRUE |
| Flex RA | TRUE |
| Integration Cost | TRUE |
| System Trans | TRUE |
| T&D | TRUE |

| Lifecycle Value from DER by Component ($) | Circuit 1107 | All Affected Areas |
|---|---|---|
| Energy | $1,982,819 | $1,982,819 |
| Gen Capacity | $555,478 | $555,478 |
| Ancillary Services | $18,393 | $18,393 |
| CO2 | $797,824 | $797,824 |
| RPS | $808,743 | $808,743 |
| Flex RA | -$306,118 | -$306,118 |
| Integration Cost | -$221,372 | -$221,372 |
| System Transmission | $0 | $0 |
| **Local T&D** | **$0** | **$1,956,858** |
| **Total Avoided Cost ($)** | **$3,635,767** | **$5,592,625** |

FIGURE 14 ‘DER AVOIDED COSTS’ SECTION

### 9.2.4. DER Hourly Shape and Calculations Section

In the ‘DER Hourly Shape and Calculations’ section (Row 52), the user will need to input a DER hourly shape for the entire year. The hourly shape is entered in the yellow highlighted cells (See Figure 15). In the ‘Hourly lifecycle unit avoided costs (hourly $/kW)’ area, this area provides the hourly net present value by component for the contracted life of the DER solution. This output with the hourly DER solution provides the information needed to calculate the total value by component in the ‘DER Avoided Costs’ section.

**DER Hourly Shape and Calculations**

| User input for DER Hourly Shape | | | | Hourly lifecycle unit avoided costs (hourly $/kW). Adjusted for exclusions and losses, but not for dependability or generation multiplier | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PST Hour Starting | Month | Hour | DER at meter (kW) | Lifecycle Energy | Lifecycle Gen Cpcty | Lifecycle AS | Lifecycle CO2 | Lifecycle RPS | Lifecycle Flex RA | Local T&D for Circuit 1107 | Local T&D for All Included Affected Areas |
| 1/1/15 12:00 AM | 1 | 0 | 0.00 | $0.58 | $0.00 | $0.01 | $0.18 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 1:00 AM | 1 | 1 | 0.00 | $0.54 | $0.00 | $0.00 | $0.17 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 2:00 AM | 1 | 2 | 0.00 | $0.53 | $0.00 | $0.00 | $0.17 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 3:00 AM | 1 | 3 | 0.00 | $0.52 | $0.00 | $0.00 | $0.17 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 4:00 AM | 1 | 4 | 0.00 | $0.54 | $0.00 | $0.00 | $0.17 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 5:00 AM | 1 | 5 | 0.00 | $0.59 | $0.00 | $0.01 | $0.18 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 6:00 AM | 1 | 6 | 0.00 | $0.54 | $0.00 | $0.00 | $0.17 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 7:00 AM | 1 | 7 | 0.00 | $0.53 | $0.00 | $0.00 | $0.17 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 8:00 AM | 1 | 8 | 105.30 | $0.52 | $0.00 | $0.00 | $0.17 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 9:00 AM | 1 | 9 | 720.21 | $0.48 | $0.00 | $0.00 | $0.17 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 10:00 AM | 1 | 10 | 154.16 | $0.45 | $0.00 | $0.00 | $0.17 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 11:00 AM | 1 | 11 | 293.76 | $0.43 | $0.00 | $0.00 | $0.17 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 12:00 PM | 1 | 12 | 515.30 | $0.41 | $0.00 | $0.00 | $0.17 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 1:00 PM | 1 | 13 | 175.15 | $0.37 | $0.00 | $0.00 | $0.17 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 2:00 PM | 1 | 14 | 940.02 | $0.40 | $0.00 | $0.00 | $0.17 | $0.17 | $0.00 | $0.00 | $0.02 |
| 1/1/15 3:00 PM | 1 | 15 | 727.53 | $0.47 | $0.00 | $0.00 | $0.17 | $0.17 | $0.00 | $0.00 | $0.02 |
| 1/1/15 4:00 PM | 1 | 16 | 174.38 | $0.70 | $0.00 | $0.01 | $0.21 | $0.17 | $0.00 | $0.00 | $0.02 |
| 1/1/15 5:00 PM | 1 | 17 | 0.00 | $0.87 | $0.00 | $0.01 | $0.26 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 6:00 PM | 1 | 18 | 0.00 | $0.89 | $0.00 | $0.01 | $0.27 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 7:00 PM | 1 | 19 | 0.00 | $0.80 | $0.00 | $0.01 | $0.24 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 8:00 PM | 1 | 20 | 0.00 | $0.81 | $0.00 | $0.01 | $0.25 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 9:00 PM | 1 | 21 | 0.00 | $0.71 | $0.00 | $0.01 | $0.21 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 10:00 PM | 1 | 22 | 0.00 | $0.66 | $0.00 | $0.01 | $0.20 | $0.17 | $0.00 | $0.00 | $0.01 |
| 1/1/15 11:00 PM | 1 | 23 | 0.00 | $0.58 | $0.00 | $0.01 | $0.18 | $0.17 | $0.00 | $0.00 | $0.01 |

Overview | DER Dashboard | Project Inputs & Avoided Costs | AreaPeaks | ReMapping | SystemAC | Flex RA | Settings

FIGURE 15 'DER HOURLY SHAPE AND CALCULATIONS' EXAMPLE

## 9.3. LNBA Tool Avoided Energy

The avoided cost of energy is defined as the total net present value of energy that does not need to be procured at the system level due to the generation or savings of the DER solution. In order to get the value of this offset energy, the time, length, and amount of the energy of the DER solution needs to be known. For example, if the DER solution provides one MWh of energy on January 1st, 2016 at 8 AM for one hour, the corresponding energy price for that time is $27.59/MWh. The value of this avoided energy is:

$$1\ MWh * \$27.59/MWh = \$27.59$$

### 9.3.1. Avoided Energy Losses

When placed at the appropriate location on the distribution feeders, DERs can reduce energy losses by reducing the amount of real and reactive power which must be provided by the existing generation sources to the load connected to the distribution feeder. For DERs to reduce energy losses, DERs need to be located, sized, and operated in such a way that allows for the reduction of energy/power losses, while complying with a utility's additional planning and operations requirements. Location can also impact energy losses significantly as the benefits/impacts of the same DER unit will change as a function of the point of interconnection location. In the LNBA tool, a line loss factor is used to represent the avoided energy losses.

Of note, the impact of line losses on the system level avoided costs has already been factored into the avoided cost values. Thus, there is no need for a line loss factor when calculating the system wide avoided cost values by component.

## 9.4. LNBA Tool Avoided Generation Capacity

The avoided cost of generation capacity is subdivided into three different types: system, local, and flexible capacity.

Avoided system generation capacity cost is defined as the total net present value of generation capacity that does not need to be procured at the system level, due to the reduction of needed capacity generated by the DER solution. In order to calculate the value of the system generation capacity, the time, length, and amount of the capacity of the DER solution need to be known. For example, if the DER solution provides one MW of capacity on June 30th, 2016 at 3 PM for one hour, the corresponding system capacity for that time is $0.0277/MWh. The value of this avoided system capacity is:

$$1\ MW * 1\ h * \$0.0277/MWh = \$0.03$$

For local generation capacity, the IOUs were directed to use DERAC values;[63] however, DERAC does not include local generation capacity prices needed to evaluate benefits associated with avoided local RA purchases. The LNBA Tool includes a generic "Generation Capacity LCR Multiplier" so that a user can apply a local capacity premium to the DERAC system generation capacity prices included in the LNBA Tool as appropriate.[64] This value is defaulted to 1.

The avoided cost for flexible capacity is defined as the value of flexible capacity that does not need to be procured from the offsetting flexible capacity provided by the DER solution. In the LNBA tool, the value of flexible capacity was assumed to be $20 / kW-yr in 2016. For future years, the $20 / kW-yr value was escalated by 5% each year. To calculate the value of the avoided flexible capacity for a specific DER solution, the DER solution hourly profile is assessed for a three-hour ramp.

## 9.5. LNBA Tool Avoided GHG, RPS, and Ancillary Services

Avoided GHG, RPS, and ancillary services costs are defined as the total net present values of each component that does not need to be procured at the system level (due to the DER providing the corresponding offset to each component). For example, if a DER solution can offset the need to procure a certain amount of RPS energy, the tool will calculate the value of the avoided RPS energy. Parallel to calculations of avoided energy and system capacity costs, the values of avoided GHG, RPS, and ancillary services are calculated by: summing the net present values (using the hourly DER values) and multiplying the corresponding hourly value for each component on a per MWh basis.

## 9.6. LNBA Renewable Integration Cost

The renewable integration cost in the LNBA tool represents the interim renewable integration cost adder (RICA) adopted in the 2014 renewables portfolio standard

[63] Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B, May 2, 2016, at pp. 26-27

[64] Located in the LNBA Tool DER Dashboard tab at cell K7

procurement plan decision[65]. The RICA intends to capture the costs associated with making the grid more operationally flexible.

The renewable integration cost is dependent on the solution technology. For solar sources, the renewable integration cost is $3 / MWh. For wind sources, the renewable integration cost is $4 / MWh. All other technologies are $0 / MWh. To calculate total renewable integration cost, the appropriate DER technology is selected. The $ / MWh cost is subsequently multiplied by the total energy produced by the DER solution for its contracted life.

## 9.7. Societal and Public Safety

Societal benefits are broadly defined as any benefits (or costs), including those related to public safety, that are linked to the deployment of DERs which are external to the IOUs' revenue requirements (i.e. do not have a nexus to rates).

Many environmental impacts associated with energy production have been internalized in the IOU revenue requirements through policy mechanisms such as the RPS and multi-sector GHG Cap and Trade system. Many public safety impacts associated with energy production have been internalized in the IOU revenue requirement through other regulatory mechanisms, such as mandatory inspection and maintenance programs.

There are several regulatory activities focused on societal benefits currently under-way: Energy Division is currently developing a proposal to address how societal benefits may be included in DER cost effectiveness analysis[66] in the Integrated Distributed Energy Resources (IDER) proceeding; the Commission is leading an Integrated Resource Plan proceeding, a long-term electric resource planning proceeding initiated by SB350 (2015) which incorporates statewide GHG emission reduction goals and also includes cost of air pollutants or GHG emissions local to disadvantaged communities, per statute.

These activities necessarily overlap and require close coordination; however, it is expected that information regarding specific types of societal benefits and quantification approaches will be determined in one or both of these proceedings. Such information could be used to inform future definitions or quantification of societal benefits in LNBA.

For Demo B, no societal or public safety components were quantified. Long term improvements to the LNBA methodology and tool may quantify societal and/or public safety components.

## 9.8. Example of System Level Avoided Cost Calculations

As an example calculation for the system level avoided costs as described previously, a resource was assumed to provide 100 kW for every hour of the year[67]. Other assumptions

[65] Decision Conditionally Accepting 2014 Renewables Portfolio Standard Procurement Plans and an Off-Year Supplement to 2013 Integrated Resource Plan

[66] Materials from a 9/22/2016 workshop on this topic are available online at: http://www.cpuc.ca.gov/General.aspx?id=10745

[67] LNBA Tool v2.11, 'DER Dashboard' tab, Cell F57:F8816

for this resource include: a contracted life of 10 years[68], a DER type of 'Other'[69], a default transmission avoided cost of zero[70], and a default generation capacity LCR multiplier of 1[71]. The results are providing in Table 25 by component.

TABLE 25 SYSTEM LEVEL AVOIDED COST CALCULATION EXAMPLE

| Lifecycle Value from DER by Component ($) | |
|---|---|
| Energy | $250,874 |
| Gen Capacity | $105,663 |
| Ancillary Services | $2,232 |
| CO2 | $84,511 |
| RPS | $107,105 |
| Flex RA | $0 |
| Integration Cost | $0 |
| System Transmission | $0 |
| Total System Level Avoided Cost | $550,384 |

[68] LNBA Tool v2.11, 'DER Dashboard' tab, Cell F6
[69] LNBA Tool v2.11, 'DER Dashboard' tab, Cell K3
[70] LNBA Tool v2.11, 'DER Dashboard' tab, Cell K6
[71] LNBA Tool v2.11, 'DER Dashboard' tab, Cell K7

# 10. Lessons Learned and Refinements

## 10.1. Overview

SCE has accomplished a number of milestones through the Demo B process. Using the four electric services that DERs can provide in Demo B, SCE identified five potentially deferrable projects in its selected DPA. For these five projects, analyses were performed to determine the project need requirements that must be satisfied to defer the project. In addition, SCE collaborated with PG&E and SDG&E to provide a public LNBA tool that can calculate the T&D deferral value and system level avoided costs. This LNBA tool was used to determine the final LNBA results for Demo B. Lastly, these results were mapped on SCE's existing Distributed Energy Resource Interconnection Map (DERiM) demonstrating the locational difference in value of deferring five grid upgrade projects. The information provided as part of SCE's Demo B process can help stakeholders understand the optimal location to site DERs.

Throughout the Demo B process, SCE discovered several lessons learned and areas for improvement. These learnings are from areas including the LNBA tool, the mapping process, need identification, and methodology improvements. SCE appreciates that Demo B provided a learning opportunity to pilot the LNBA methodology and looks forward to participating in refinements to improve the output for all stakeholders. In this section, SCE outlines aspects of the LNBA tool, and underlying support processes for the tool, that it believes require further refinement.

## 10.2. Demo B Processes

Demo B is an exploration of the application of emerging LNBA methodologies. Existing tools are not able to provide all necessary information to meet the requirements of Demo B, and therefore, SCE had to manually perform certain processes. As an example, the development of the annual hourly (8760) need shape as an input for the LNBA tool. Load shape development required engineers to perform a lengthy manual process to gather needed data and perform the load shape development process described in Chapter 4, which was just for the five projects in the Demo B DPA. Engineers will require a streamlined process and appropriate tools will be required to enable the system-wide deployment of the LNBA methodology.

SCE looks to develop the tools necessary to streamline the planning process and incorporate various aspects to help with planning for DERs as solutions to electric system needs. This includes improvements to forecasting load profiles, developing alternatives to serve forecasted load profiles, and analyzing if DER portfolios can serve forecasted load profiles. In the future, the goal is to leverage tools to provide outputs that would streamline updates to the LNBA and DER solicitation processes.

## 10.3. Tools for Transmission / Subtransmission Projects Deferral Analysis

The existing power flow analysis tools need to be enhanced to support transmission and subtransmission level analysis for project deferral.

In the selected DPA, there are no existing or proposed transmission projects to be deferred via the deployment of DERs. However, SCE has evaluated the deferral need of three subtransmission projects. This process requires power flow analysis similar to the required study for transmission projects.

Subtransmission projects are intended to provide sufficient capacity and voltage under base case as well as N-1 contingency. The networked configuration of the subtransmission systems can greatly increase the number of scenarios to be studied. Usually, the study is performed by running subtransmission system power flows with fixed substation loading and then introducing system contingencies. To account for potential DER impact, a large amount of power flow analyses including contingencies under different substation loading conditions are required. During the need analysis for these subtransmission projects, a manual process was utilized to incrementally reduce the loading (to represent the generation from technology agnostic DERs) at one substation at a time in order to identify the most effective substation across all the substations in the DPA. However, in some cases, there may be restrictive factors that prevent the needed amount of DERs from achieving deferral such as the required load reduction from DERs exceeds the integration capacity. An ideal study process shall be able to investigate the possibility of various alternative scenarios of optimally spreading DER installations throughout the system to different substations. Without an automated process to perform these analysis, significant manual work is required.

In order to confidently value transmission and/or subtransmission savings derived from DERs, it is recommended that a power flow tool enhancement is pursued in order to support the capability of automation process.

On the other hand, the full scope of work required to achieve a methodology whereby SCE can concretely attribute DER derived load reduction to transmission project deferral was not fully identified at the onset of the demonstration and therefore remains unresolved as the demo B comes to a close.

## 10.4. LNBA Tool Update

The LNBA tool needs to be enhanced to support the benefit analysis of deferring a project with multiple locational elements.

In addition to the scenarios of spreading DER installations to different substations for a subtransmission project deferral, distribution projects can also have requirements to involve a multiple locational benefit analysis. As an example, the Goshen Substation project identified load reduction requirements at Goshen Substation, Curtis circuit, and Monson circuit. The Monson circuit is fed from Oak Grove Substation in a geographically different location. As the existing LNBA tool used for Demo B doesn't have the capabilities to provide value for multiple locations if a single planning need requires DER to be installed at several different locations or substations, the total load reduction requirements for Goshen substation and the two circuits were aggregated. This simplification allows the deferral value to be calculated for the purpose of Demo B. However, the aggregation of the need used in the LNBA tool does not convey the complexity of the project with its multiple location requirements.

Future refinements to the LNBA tool that account for DERs sited at multiple locations would provide a more accurate LNBA calculation, closer to how DERs would be procured to meet electric system needs, and provide optimized DER value to deferring traditional projects that require DERs at multiple locations.

## 10.5. Online Map Development

The online mapping tool needs to be able to present large volumes of data. The ACR requires the map to publish nodal results. This requirement presented an exponentially larger set of data over which was previously published for SCE's initial DRP filing. This increase in data caused an excessive draw on the ArcGIS Online cloud server and led to an incomplete display of the dataset. For the projects analyzed in Demo B, the LNBA results were not unique on a section-to-section basis, so SCE elected to publish the concatenated circuits instead of the individual line sections. This enabled the ability to load the entire DPA in a single view. SCE expects the volume of data to continue to increase in the near future, and therefore emphasizes the need to invest in and deploy more robust hardware and software infrastructure that is capable of supporting the growing need. Alternatively, SCE recommends aligning the granularity of the map with the nature of the results. For example, if results do not differ on a section-to-section basis, or only differ with a negligible margin, the number of mapped line sections should be reduced to provide a more user-friendly experience, while minimizing impacts to map performance. Additionally, SCE recommends only publishing LNBA results from the forecast scenarios adopted for planning, as these align with the processes used to evaluate DER interconnections.

# Appendix 1: Map Display

This section describes the design for Demo B heat maps. As required by the ACR, the Demo B map shall provide: 1) LNBA results using two DER growth scenarios: (a) as used in distribution planning process, (b) the very high DER growth scenario, in the form of a heat map; 2) Deferrable projects providing location and specifications; 3) The electric services for the project locations; 4) The DER growth scenarios.

## 1. Overview of Map

The results of DRP Demo B Project have been published as additional layers within SCE's existing Distributed Energy Resource Interconnection Map (DERiM). SCE's existing DERiM User Guide has been expanded to include Demo B Definitions (http://on.sce.com/derimguide). Lastly, SCE will publish comprehensive downloadable result files, to a new webpage referred to as the DRP Demo Results Library (http://on.sce.com/drpdemos).

- DERiM Web Map: http://on.sce.com/derime
- Expanded DERiM User Guide: http://on.sce.com/derimguide
- DRP Demo Results Library: http://on.sce.com/drpdemos

DERiM is an interactive web map developed on ESRI's ArcGIS online platform. It performs calculations by collecting data from SCE's GIS, interconnection, and planning tools. DERiM aims to provide the public with the SCE system data necessary to enable strategic DER siting. Users click on map features to obtain a variety of results, including ICA results. All of the information published to the map or downloadable files will be subject to Personal Identifiable Information (PII) or Critical Energy Infrastructure Information (CEII) compliance requirements.

## 2. Map Design

The following layer descriptions provide an overview of the features (graphic representation), attributes (data obtained through pop-up or otherwise) and symbology (how colors and symbols are applied to the features) within the Demo B layers.

## Demonstration Projects A & B: DPA

| Layer | Demo A & B - DPA |
|---|---|
| **Features** | Buffer area encompassing the extent of all distribution circuits within each DPA |
| **Attributes** | -DPA<br>-[Link] DERiM User Guide<br>-[Link] DERiM WebApp (Load Profiles)<br>-[Link] DRP Demo Results Library |
| **Symbology** | Unique (random) |
| **Symbology Key** | DPA Name |

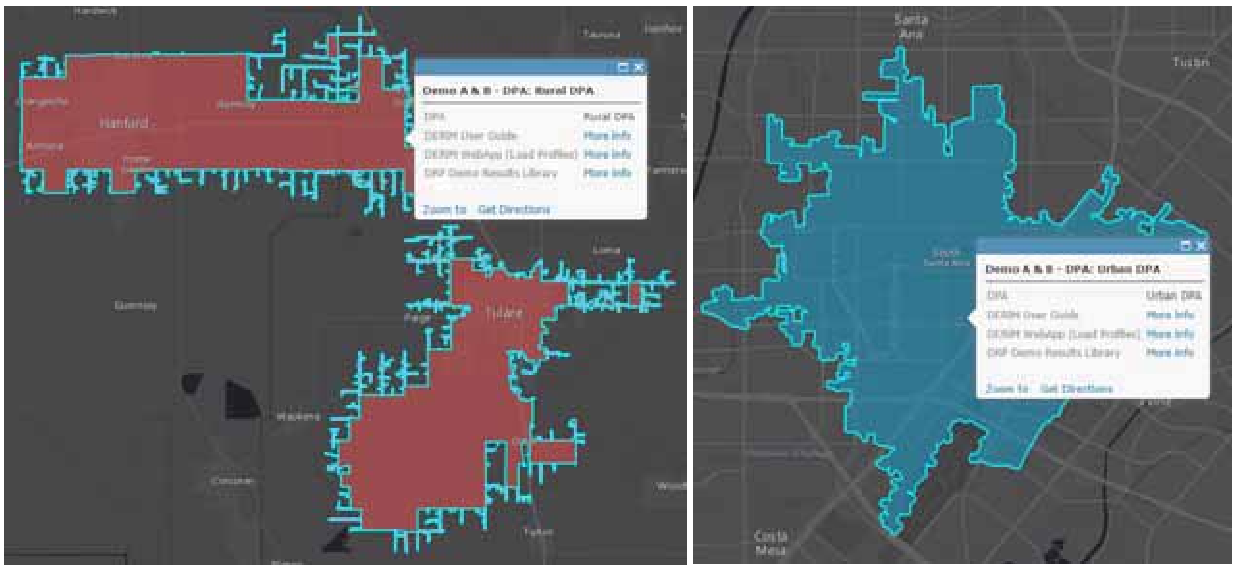


FIGURE 16: DPA LAYER

## Demonstration Projects A & B: Substations

| Layer | Demo A & B - Substations |
|---|---|
| **Features** | Point locations for substations |
| **Attributes** | -Substation<br>-System<br>-Existing Generation (MW)<br>-Queued Generation (MW)<br>-Total Generation (MW)<br>-[Link] DERiM User Guide<br>-[Link] DERiM WebApp (Load Profiles)<br>-[Link] DRP Demo Results Library |
| **Symbology** | Single symbol |
| **Symbology Key** | N/A |

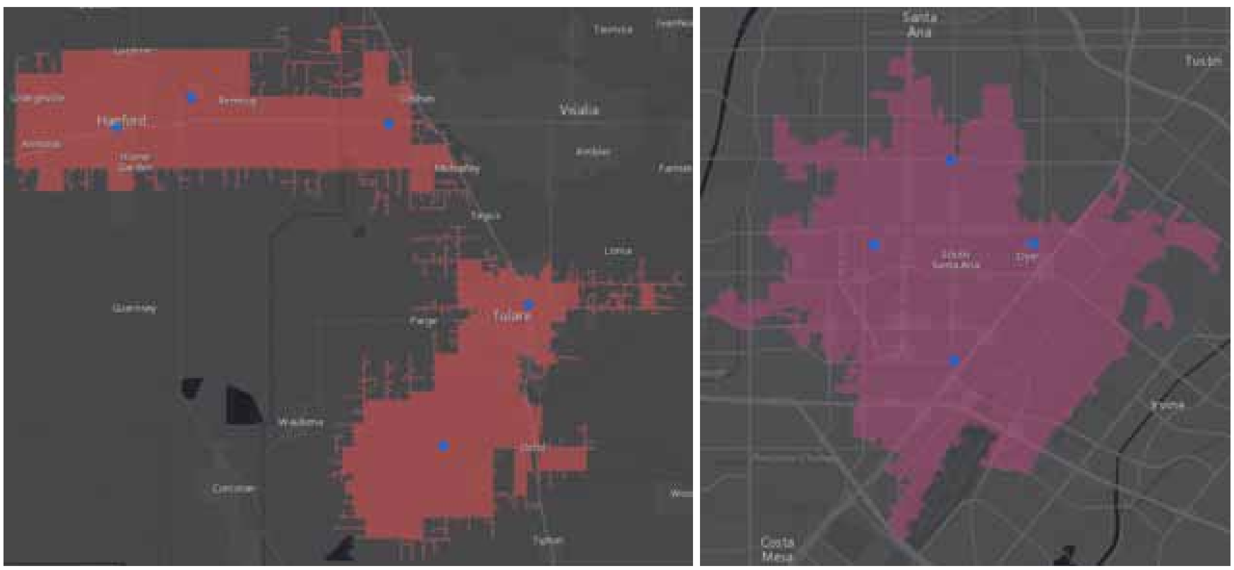


FIGURE 17: SUBSTATIONS LAYER

| (1 of 2) | |
|---|---|
| **Demo A & B - Substations: Goshen 66/12 kV** | |
| Substation | Goshen 66/12 kV |
| System | Rector 220/66 System |
| Existing Generation (MW) | 4.60 |
| Queued Generation (MW) | 2.25 |
| Total Generation (MW) | 6.84 |
| DERiM User Guide | More info |
| DERiM WebApp (Load Profiles) | More info |
| DRP Demo Results Library | More info |

FIGURE 18: SUBSTATION POP-UP

## Demonstration Project B: DER Growth Scenario – Planning

| | |
|---|---|
| Layer | Demo B - DER Growth Scenario, Planning |
| **Features** | 3-phase primary conductor as a single contiguous feature by circuit |
| **Attributes** | -DER Growth Scenario<br>-Circuit<br>-Voltage (kV)<br>-Substation<br>-System<br>-2025 DER Coincident Peak (MW)<br>-[Link] DERiM User Guide<br>-[Link] DRP Demo Results Library |
| **Symbology** | Color Gradient: red (low) to green (high) |
| **Symbology Key** | 2025 DER Coincident Peak (MW) |

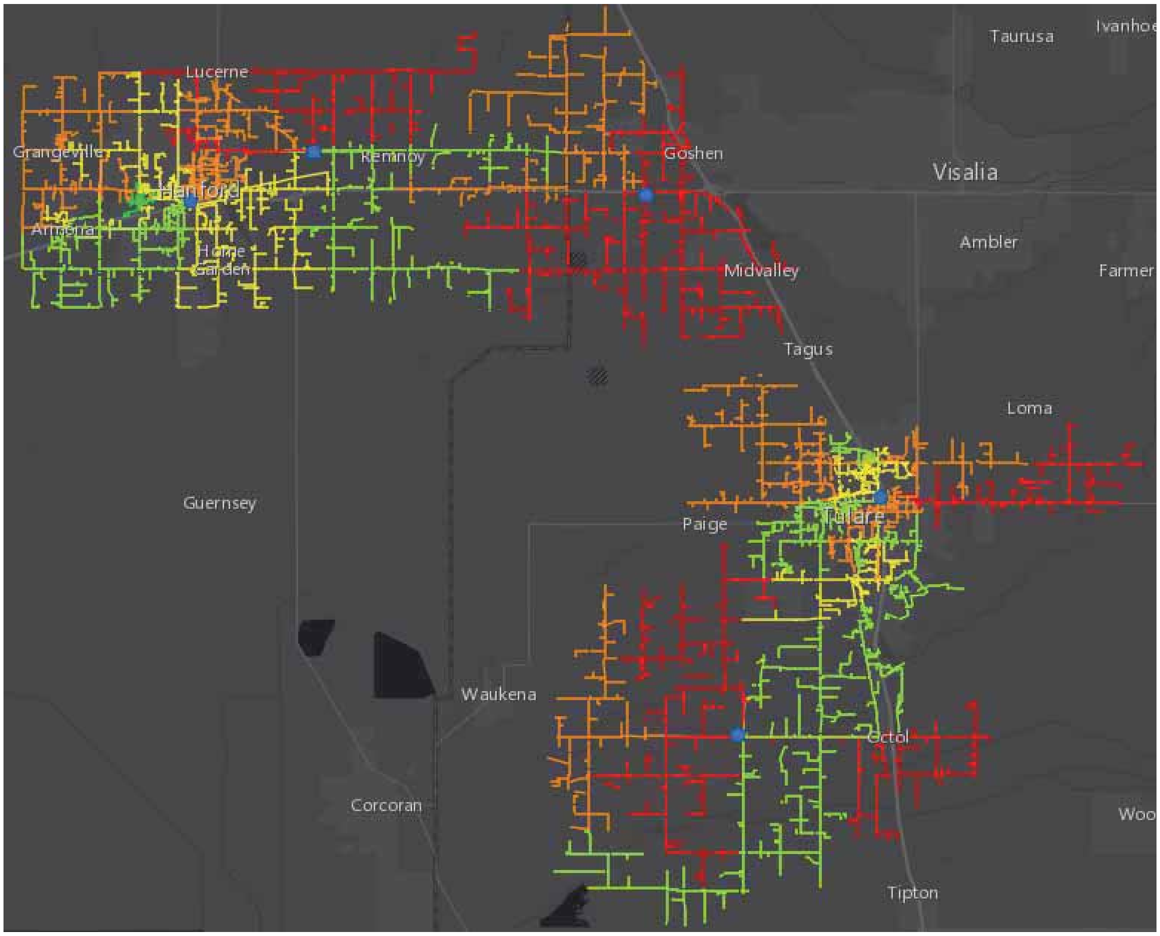


FIGURE 19: DRP GROWTH SCENARIO, PLANNING LAYER

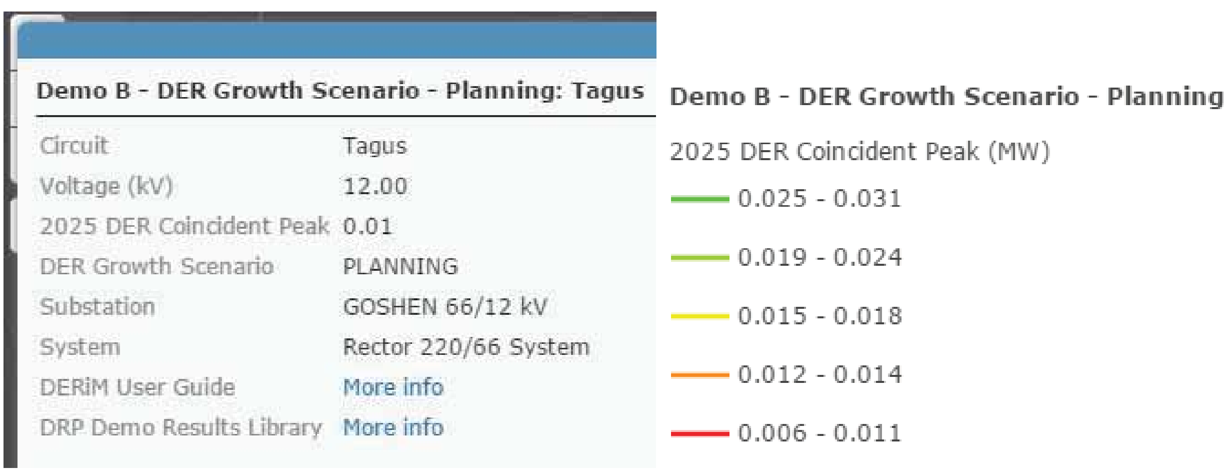


FIGURE 20: DRP GROWTH SCENARIO, PLANNING POP-UP & LEGEND

## Demonstration Project B: DER Growth Scenario – Very High

| Layer | Demo B - DER Growth Scenario, Very High |
|---|---|
| **Features** | 3-phase primary conductor as a single contiguous feature by circuit |
| **Attributes** | -DER Growth Scenario<br>-Circuit<br>-Voltage (kV)<br>-Substation<br>-System<br>-2025 DER Coincident Peak (MW)<br>-Note<br>-[Link] DERiM User Guide<br>-[Link] DRP Demo Results Library |
| **Symbology** | Color Gradient: red (low) to green (high) |
| **Symbology Key** | 2025 DER Coincident Peak (MW) |

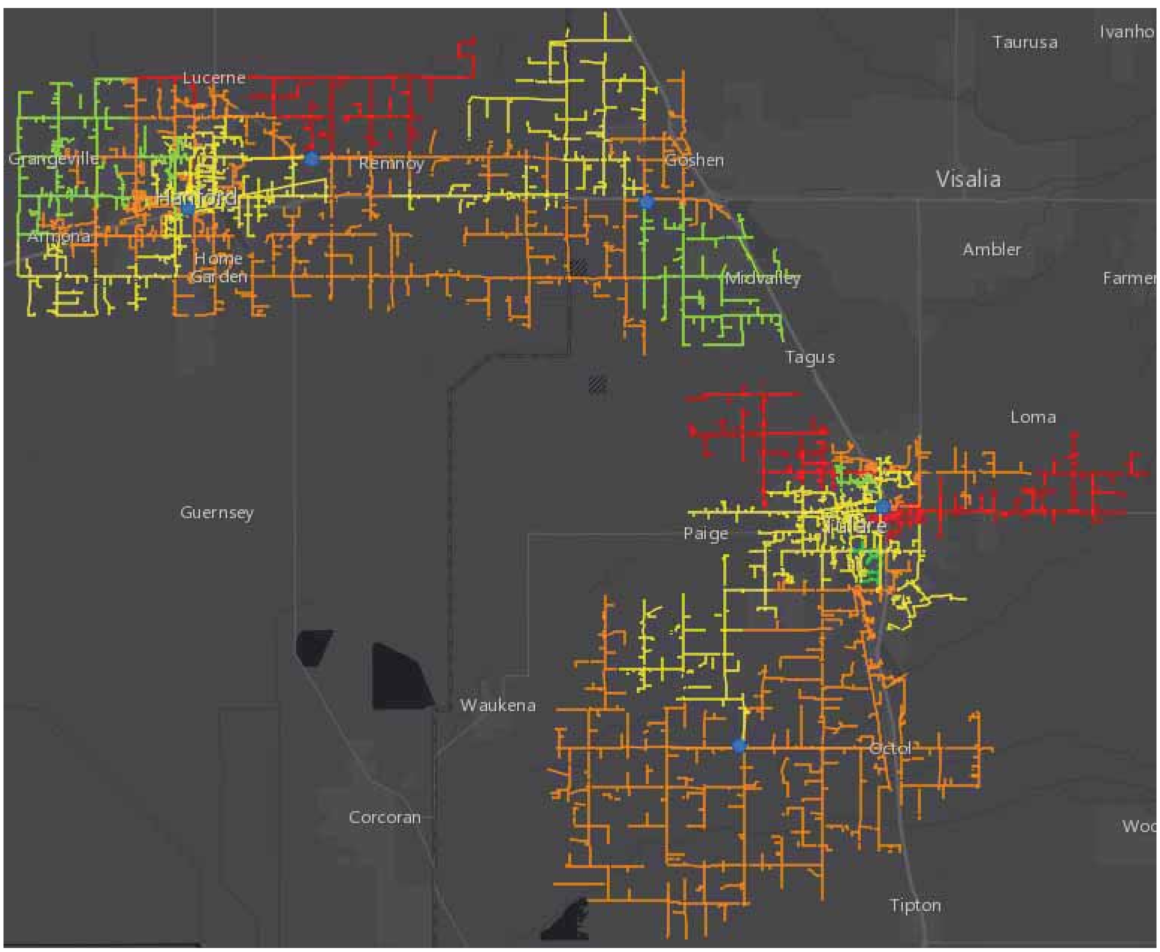


FIGURE 21: DRP GROWTH SCENARIO, VERY HIGH LAYER


FIGURE 22: DRP GROWTH SCENARIO, VERY HIGH POP-UP & LEGEND

## Demonstration Project B: LNBA Short-term, Planning

| | | |
|---|---|---|
| Layer | | Demo B - LNBA Short-term, Planning |
| **Features** | | 3-phase primary conductor as a single contiguous feature by circuit |
| **Attributes** | -Circuit<br>-Voltage (kV)<br>-System<br>-Substation<br>-DER Growth Scenario<br>-LNBA Results Timeframe<br>-Project 1 Title<br>-Project 1 Description<br>-Project 1 In-service Date<br>-Grid Service(s) 1<br>-LNBA Results 1 | -Project 2 Title<br>-Project 2 Description<br>-Project 2 In-service Date<br>-Grid Service(s) 2<br>-LNBA Results 2<br>-Project 3 Title<br>-Project 3 Description<br>-Project 3 In-service Date<br>-Grid Service(s) 3<br>-LNBA Results 3<br>-[Link] DERiM User Guide<br>-[Link] DRP Demo Results Library |
| **Symbology** | | Color Gradient: red (low) to green (high) |
| **Symbology Key** | | LNBA Results 1 |

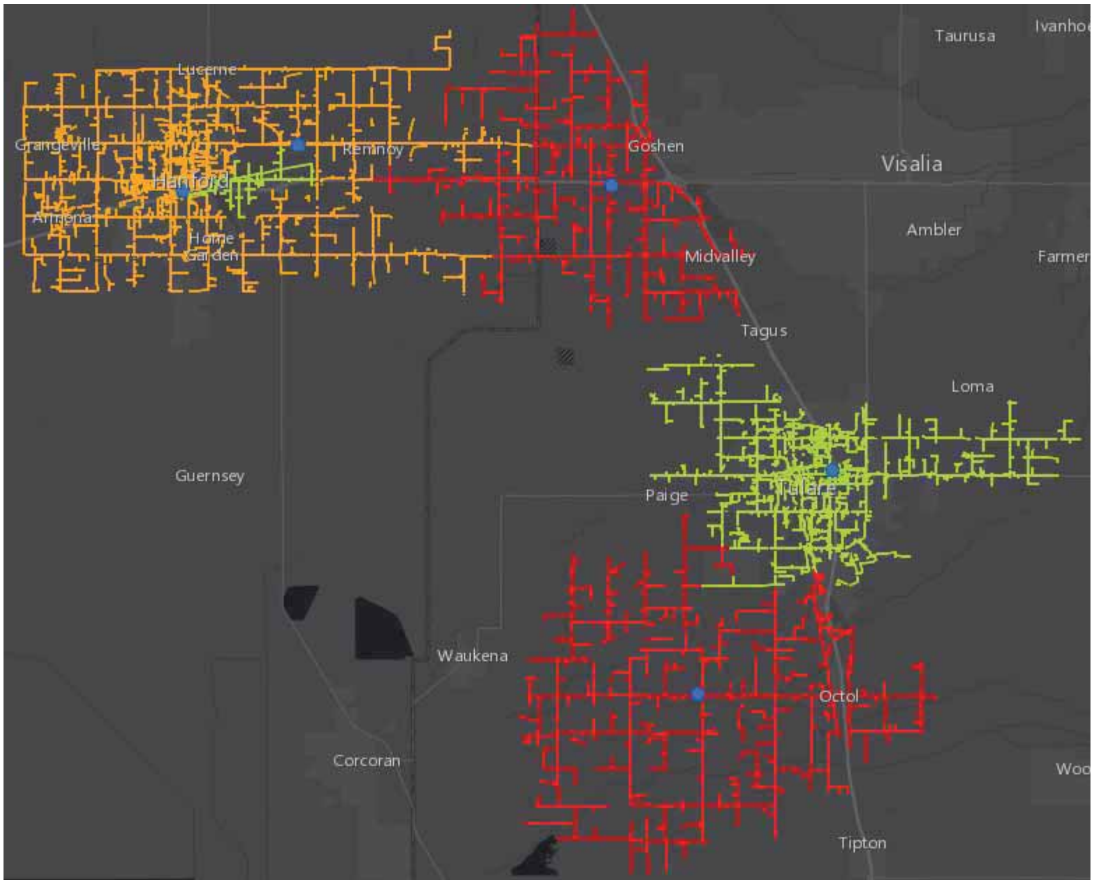


FIGURE 23: LNBA SHORT-TERM, PLANNING LAYER

(1 of 2)

**Demo B - LNBA Short-term, Planning: Cattle**

| | |
|---|---|
| Circuit | Cattle |
| Voltage (kV) | 12.00 |
| Substation | TULARE 66/12 kV |
| System | Rector 220/66 System |
| DER Growth Scenario | Planning |
| LNBA Results Timeframe | Short-term |
| Project 1 Title | New Rector-Goshen-Liberty 66kV Subtransmission Line |
| Project 1 Description | The loading on the Rector-Liberty 66kV No. 1 and Rector-Liberty 66kV No. 2 subtransmission lines is projected to exceed the capacity limits in 2016, under N-1 line outage conditions, due to continuing load growth in the area. The project will construct approximately 1.0 mile of 66kV underground subtransmission line tapped off of the existing Goshen-Liberty 66kV subtransmission line to Liberty substation. |
| Project 1 In-service Date | June 01, 2018 |
| Grid Service(s) 1 | Transmission and Distribution Capacity Deferral |
| LNBA Results 1 | $$$ |

FIGURE 24: LNBA SHORT-TERM, PLANNING POP-UP

All six of the LNBA Results layers will leverage the legend shown below.

**Demo B - LNBA Short-term, Planning**

$

$$

$$$

$$$$

FIGURE 25: LNBA RESULTS LEGEND

## Demonstration Project B: LNBA Mid-term, Planning

| | | |
|---|---|---|
| Layer | | Demo B - LNBA Mid-term, Planning |
| **Features** | | 3-phase primary conductor as a single contiguous feature by circuit |
| **Attributes** | -Circuit<br>-Voltage (kV)<br>-System<br>-Substation<br>-DER Growth Scenario<br>-LNBA Results Timeframe<br>-Project 1 Title<br>-Project 1 Description<br>-Project 1 In-service Date<br>-Grid Service(s) 1<br>-LNBA Results 1 | -Project 2 Title<br>-Project 2 Description<br>-Project 2 In-service Date<br>-Grid Service(s) 2<br>-LNBA Results 2<br>-Project 3 Title<br>-Project 3 Description<br>-Project 3 In-service Date<br>-Grid Service(s) 3<br>-LNBA Results 3<br>-[Link] DERiM User Guide<br>-[Link] DRP Demo Results Library |
| **Symbology** | | Color Gradient: red (low) to green (high) |
| **Symbology Key** | | LNBA Results 1 |

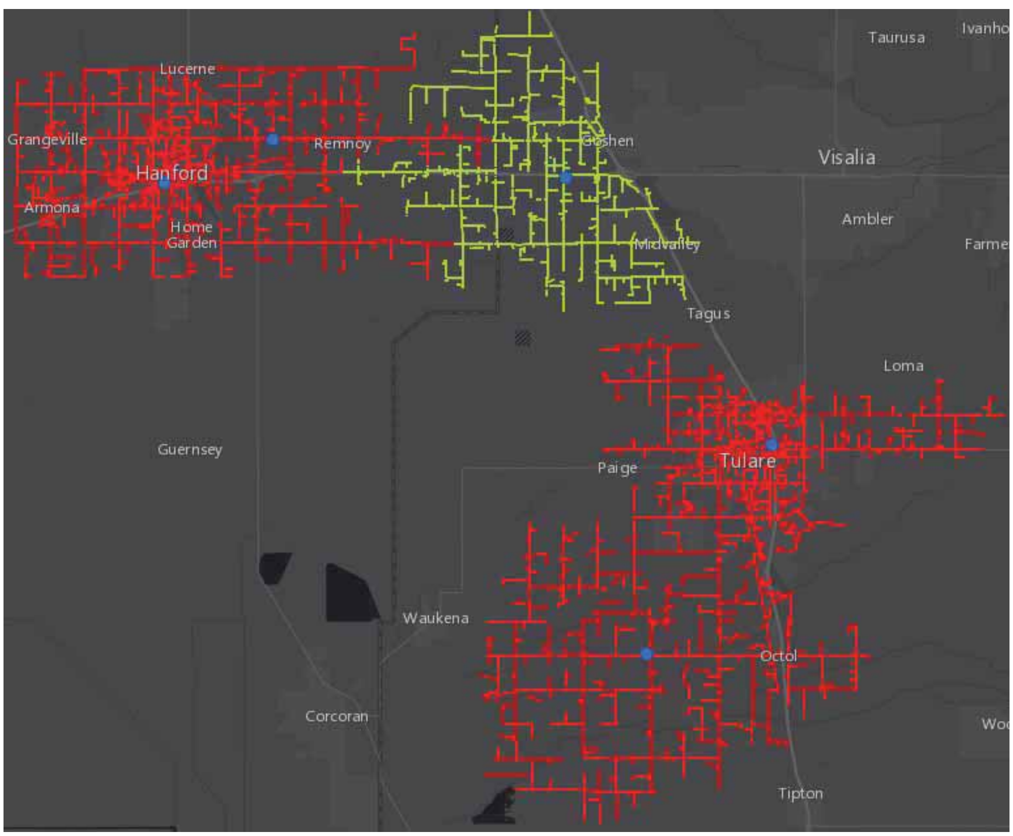


FIGURE 26: LNBA MID-TERM, PLANNING LAYER

## Demonstration Project B: LNBA Long-term, Planning

| | | |
|---|---|---|
| Layer | | Demo B - LNBA Long-term, Planning |
| **Features** | | 3-phase primary conductor as a single contiguous feature by circuit |
| **Attributes** | -Circuit<br>-Voltage (kV)<br>-System<br>-Substation<br>-DER Growth Scenario<br>-LNBA Results Timeframe<br>-Project 1 Title<br>-Project 1 Description<br>-Project 1 In-service Date<br>-Grid Service(s) 1<br>-LNBA Results 1 | -Project 2 Title<br>-Project 2 Description<br>-Project 2 In-service Date<br>-Grid Service(s) 2<br>-LNBA Results 2<br>-Project 3 Title<br>-Project 3 Description<br>-Project 3 In-service Date<br>-Grid Service(s) 3<br>-LNBA Results 3<br>-[Link] DERiM User Guide<br>-[Link] DRP Demo Results Library |
| **Symbology** | | Color Gradient: red (low) to green (high) |
| **Symbology Key** | | LNBA Results 1 |

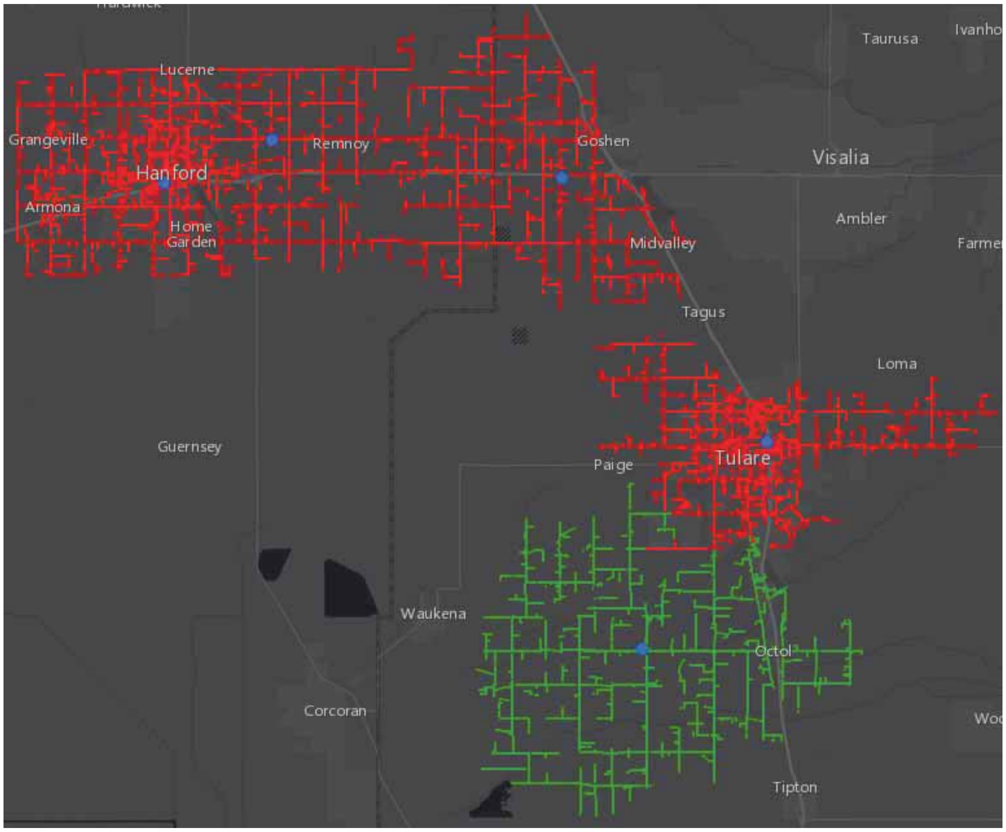


FIGURE 27: LNBA LONG-TERM, PLANNING LAYER

# Demonstration Project B: LNBA Short-term, Very High

| | | |
|---|---|---|
| Layer | | Demo B - LNBA Short-term, Very High |
| Features | | 3-phase primary conductor as a single contiguous feature by circuit |
| Attributes | -Circuit<br>-Voltage (kV)<br>-System<br>-Substation<br>-DER Growth Scenario<br>-LNBA Results Timeframe<br>-Project 1 Title<br>-Project 1 Description<br>-Project 1 In-service Date<br>-Grid Service(s) 1<br>-LNBA Results 1 | -Project 2 Title<br>-Project 2 Description<br>-Project 2 In-service Date<br>-Grid Service(s) 2<br>-LNBA Results 2<br>-Project 3 Title<br>-Project 3 Description<br>-Project 3 In-service Date<br>-Grid Service(s) 3<br>-LNBA Results 3<br>-[Link] DERiM User Guide<br>-[Link] DRP Demo Results Library |
| Symbology | | Color Gradient: red (low) to green (high) |
| Symbology Key | | LNBA Results 1 |

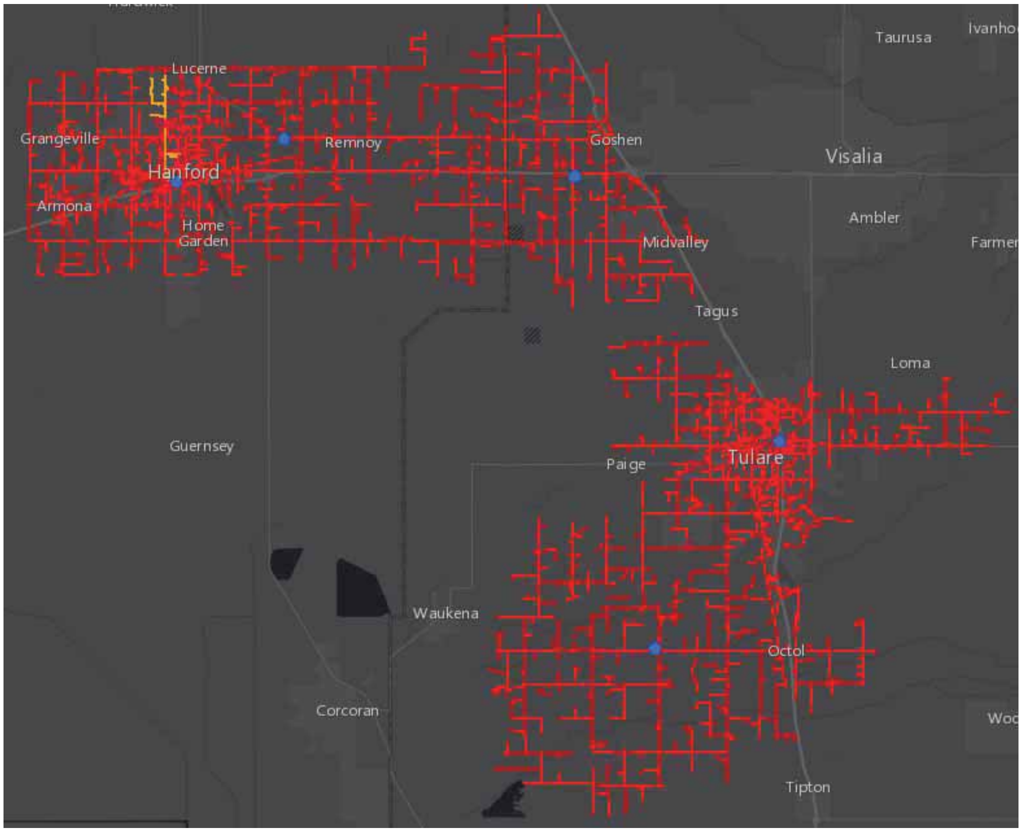


FIGURE 28: LNBA SHORT-TERM, VERY HIGH LAYER

## Demonstration Project B: LNBA Mid-term, Very High

| | | |
|---|---|---|
| Layer | | Demo B - LNBA Mid-term, Very High |
| **Features** | | 3-phase primary conductor as a single contiguous feature by circuit |
| **Attributes** | -Circuit<br>-Voltage (kV)<br>-System<br>-Substation<br>-DER Growth Scenario<br>-LNBA Results Timeframe<br>-Project 1 Title<br>-Project 1 Description<br>-Project 1 In-service Date<br>-Grid Service(s) 1<br>-LNBA Results 1 | -Project 2 Title<br>-Project 2 Description<br>-Project 2 In-service Date<br>-Grid Service(s) 2<br>-LNBA Results 2<br>-Project 3 Title<br>-Project 3 Description<br>-Project 3 In-service Date<br>-Grid Service(s) 3<br>-LNBA Results 3<br>-[Link] DERiM User Guide<br>-[Link] DRP Demo Results Library |
| **Symbology** | | Color Gradient: red (low) to green (high) |
| **Symbology Key** | | LNBA Results 1 |

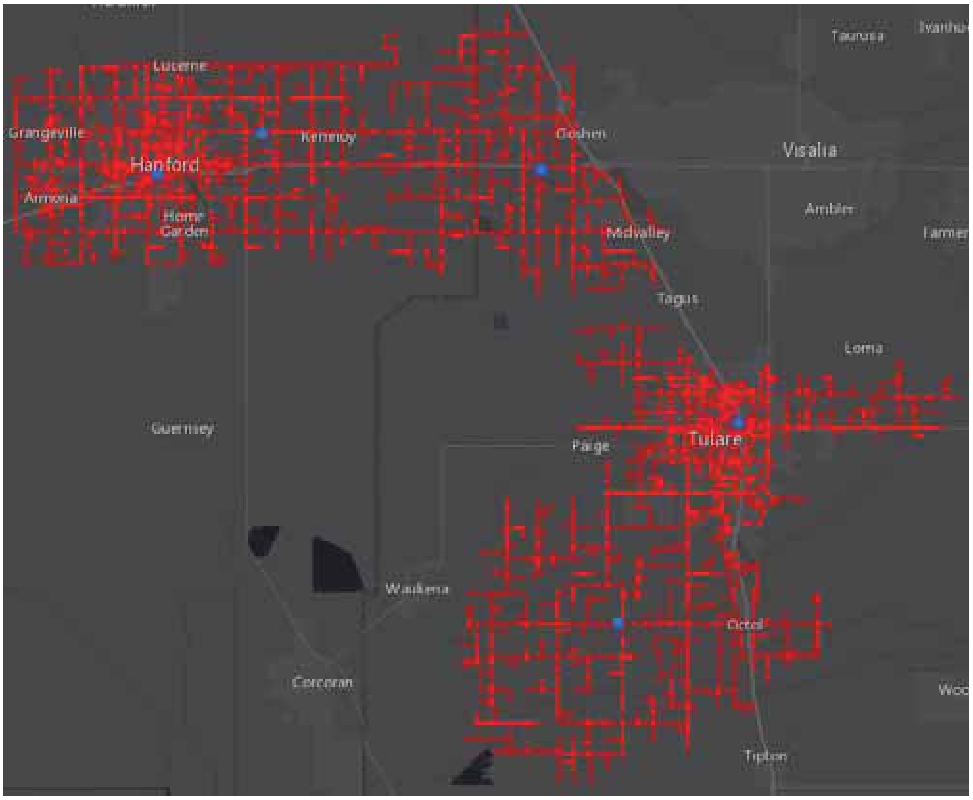


FIGURE 29: LNBA MID-TERM, VERY HIGH LAYER

## Demonstration Project B: LNBA Long-term, Very High

| | | |
|---|---|---|
| Layer | | Demo B - LNBA Long-term, Very High |
| **Features** | | 3-phase primary conductor as a single contiguous feature by circuit |
| **Attributes** | -Circuit<br>-Voltage (kV)<br>-System<br>-Substation<br>-DER Growth Scenario<br>-LNBA Results Timeframe<br>-Project 1 Title<br>-Project 1 Description<br>-Project 1 In-service Date<br>-Grid Service(s) 1<br>-LNBA Results 1 | -Project 2 Title<br>-Project 2 Description<br>-Project 2 In-service Date<br>-Grid Service(s) 2<br>-LNBA Results 2<br>-Project 3 Title<br>-Project 3 Description<br>-Project 3 In-service Date<br>-Grid Service(s) 3<br>-LNBA Results 3<br>-[Link] DERiM User Guide<br>-[Link] DRP Demo Results Library |
| **Symbology** | | Color Gradient: red (low) to green (high) |
| **Symbology Key** | | LNBA Results 1 |

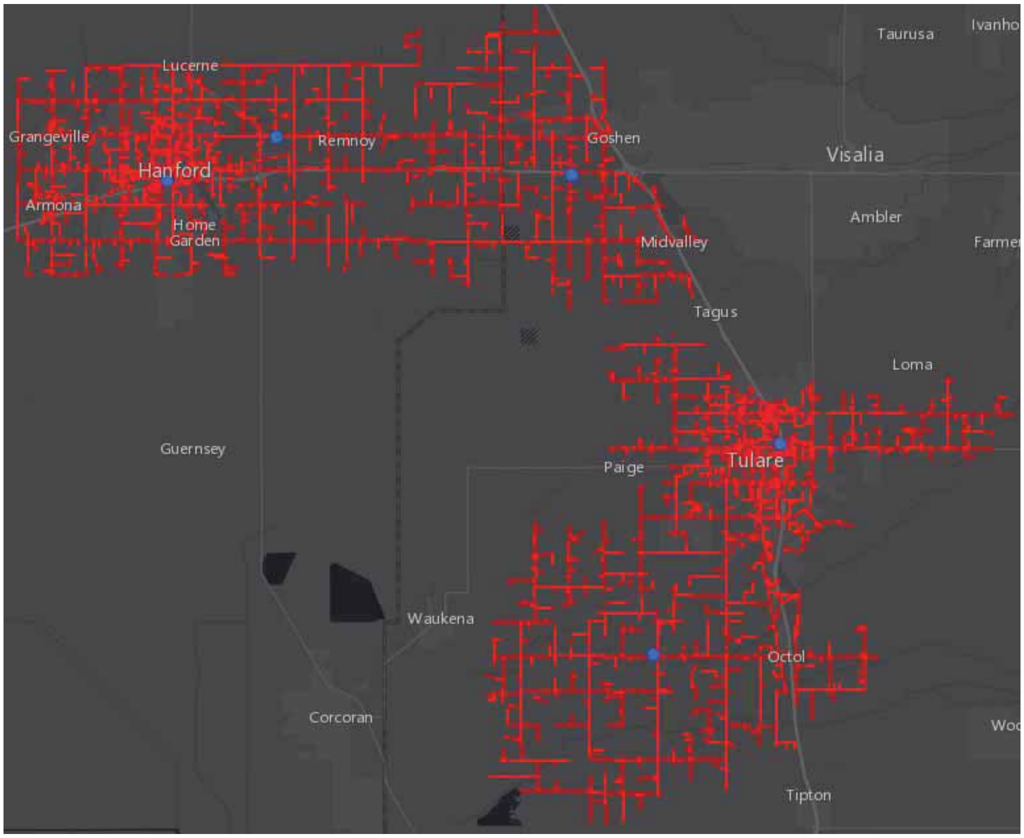


FIGURE 30: LNBA LONG-TERM, VERY HIGH LAYER

## 3. Data

The downloadable Demo B dataset will include the following information:

1.) DER growth scenarios forecasts at the circuit level.
2.) Deferrable project information as defined in the ACR requirements.
3.) LNBA results in symbolic format.

# Appendix 2: E3 LNBA Tool Documentation

This document is a quick user guide for the LNBA tool that calculates locational avoided costs for utility local T&D projects, as well as avoided cost benefits for a load reduction shape. The document is organized into three sections:

1. Guide for DER stakeholders (DER users)
2. Additional info for utility staff (that populate the project cost-related inputs)
3. Methodology overview

The LNBA Tool is an excel spreadsheet that makes minimal use of Visual Basic for Application (VBA) functions in order to maintain transparency and understandability. There is one VBA function that is used for interpolation of some inputs, and for that reason, VBA macros should be enabled when using this tool.

The overall structure of the tool is summarized below.

TABLE 26 TOOL STRUCTURE OVERVIEW

| Tab | Function | Description |
|---|---|---|
| DER Dashboard | Interface tab for DER bidders | Determines the total avoided cost benefits of DER by location. Requires the user to select an area, and input an 8760-hour stream of DER load reductions (DER Output) in kW. The DER output should match the weather and chronology (weekdays/weekends) of the T&D information. The dates of the T&D info and the weather data can be found on the ReMapping tab. |
| Project Inputs & Avoided Costs | Utility inputs and calculation of local T&D deferral avoided costs | ***Utility Inputs:*** Project information such as cost and need for up to ten projects as well as generic utility discount rate and default inflation rate information. Also allows the utility to define the links between areas to allow for quantification of the benefits in the DER installation area, as well as other affected T&D areas. ***Results:*** Base low and high case avoided costs by project and aggregated for all projects affected by DER installed in the area. |
| AreaPeaks | Utility inputs to define the peak need and timing | Utility inputs of area loads (and peak threshold) or hourly area needs. |
| Remapping | Align system avoided costs with weather and chronology of the local T&D deferral avoided costs | Utility Inputs tab. Weather information by area is input in order to allow the system avoided costs to be remapped to more closely map the chronology (weekends) and temperature characteristics of the T&D information. |
| SystemAC | Repository for CPUC system avoided costs | Hourly system avoided costs. Values are from the 2016 Interim Update CPUC Avoided Costs. |
| FlexRA | Inputs and calculation of avoided costs for ramping | Flexible Resource Adequacy Costs and timing of ramping need period. |

| | | |
|---|---|---|
| Settings | Various | Contains lists for dropdown boxes and utility-specific information that need only be updated on an annual basis. Data includes equipment revenue requirement multipliers and O&M costs as a percentage of direct costs. No project-specific inputs. |

The next section describes the inputs on the DER Dashboard with which a DER stakeholder would interact.

## 1. Guide for DER Users.

DER users will enter their project information in the DER Dashboard tab of the tool. The user inputs are listed below. Yellow cells in the tool indicate user data inputs, orange cells indicate drop-down selections.

TABLE 27 DER USER INPUTS

| Item | Location | Note/Comment |
|---|---|---|
| DER Location | F4 | Select the utility project area from the dropdown list. This should reflect the planned physical location of the DER installation. If there are more than one areas that apply to the location, select the most geographically specific choice. For example, if the DER is being installed at UCLA, and the area choices included Westwood and Los Angeles County, one should select Westwood. |
| Dependability in Local Area | F5 | Factor used to de-rate the local DER capacity reduction amount. 100% indicates that DER load reductions can be relied upon as dependable. A value of, say 90%, indicates a 10% reduction to the DER impact of local capacity. This factor is not applied to system benefits. |
| DER Useful Life | F20 | Number of years the DER is expected to persist. This is used to calculate lifecycle system benefits for the DER |
| DER install year | F21 | Year (e.g.: 2017) that the DER would be operational and able to reduce the area peak. If the DER would be operational after the seasonal peak for the project area, enter the install year as the following year. |
| Defer T&D to this year | F22 | DER will likely only be able to defer the local T&D investment for fewer years than the DER expected useful life. Enter the number of years of project need that the DER could avoid and thereby allow deferral of the T&D project. The later the year, potentially the larger the deferral benefit, but also the higher the peak reduction need.<br><br>The user can derive deferral years by entering DER profile and checking against the required electrical characteristics for each year, and can checking the deferral values incrementally for each year following the DER Install Year. |
| DER Type | K3 | Indicate if the DER is a solar or wind project. This information is used to assign integration costs to the solar and wind DER based on lifecycle MWh production. |
| DER at Meter | F57:F8816 | DER output or load reduction at the customer meter or installation site. Data is in kW and does not reflect upstream losses. If the DER is weather sensitive, interacts with usage schedules that vary between weekdays and weekends/holidays, or is dispatchable, the user should take care that the values correspond to the year chronology and weather being used by the utility for defining the peak needs of each area. That information can be found in the Remapping tab columns H through M. |

TABLE 28 DER AND PROJECT OUTPUT

| Item | Location | Note / Comment |
|---|---|---|
| T&D Value Basis | E13 | Allows T&D value to be calculated in two ways. Requirement-based threshold or Allocation-based threshold differences are described in the methodology section |
| DER Peak Reductions | | |
| **kW Needed** | D22:D33 | Maximum deficiency for each project from the DER Install Yr up to but not including the 'Defer T&D to this year" input. |
| **Need after Dependable DER** | E22:E33 | Maximum area need in the same year used for the "kW Needed" after subtracting dependable DER load reductions. |
| **Dependable DER Reduction** | F22:F33 | kW Needed less "Need after Dependable DER" |
| **Potential Deferral Value ($)** | H22:H33 | Maximum value if all applicable projects can be deferred by the DER up to the "Defer T&D to this year" |
| **Inclusion choice** | I22:I33 | Setting to "exclude" will set the deferral value for the T&D project to zero. |
| **Attributed Deferral Value** | J22:J33 | Total deferral value, based on the selection of T&D Value Basis (Cell E13) and the inclusion choices. |
| Avoided Costs | | |
| **Inclusion Choice** | D41:D49 | Setting to FALSE will zero out the component in the table to the right |
| **Lifecycle values - system** | H41:I48 | Lifecycle costs and benefits provided by the DER. |
| DER kW output statistics | | |
| **DER Max Output (kW)** | N20 | Maximum of the hourly DER kW entered by the user in cells F57:F8816 |
| **Minimum** | M23:N23 | Minimum DER output during the peak hours. (Note that we use the term "DER output" in this section, but this could also apply to DER load reductions). If there is more than one project affected by the DER, there may be more peak hours in the "All Affected Areas" case, than the "Project Area" case. This will happen if the other affected areas have peak timings that differ from the project area. In that situation, the minimum could be lower for the "All Affected Areas" case. |
| **Percentiles** | M24:N26 | X% indicates DER output is BELOW this value during X% of the peak hours. |
| **Simple Average** | M27:N27 | Average DER output during the peak hours. Note that this is not the same as the average DER output over the year. |
| **PCAF Wtd Average** | M28:N28 | Sumproduct of the DER hourly output and the hourly local T&D costs divided by the sum of the hourly local T&D costs. |
| HeatMaps | | |
| **Heatmap cost selection** | S2:AQ15 | The user can display a heatmap for either the individual project area costs, or the total costs for all affected areas. The costs shown are totals by month and hour for local T&D only, and do not include system components. The heatmap is useful for illustrating the timing of the peak reduction need. |
| **DER Output** | S19:AQ32 | Heat map of the DER output or load reduction average kW by month and hour |

The next section defines additional data fields that the utilities will need to populate.

## 2. Additional Data Inputs

This section summarizes the data that utilities would need to update for their projects. The information is organized by spreadsheet tab.

## TABLE 29 UTILITY INPUTS

| Item | Location | Note / Comment |
|---|---|---|
| DER Dashboard | | |
| Transmission Avoided Cost | K6 | Total lifecycle system transmission avoided cost savings per kW of DER output or reduction. Note that this is NOT per kW of demand change at the transmission system level, so losses should be accounted for in the entered value. Default is zero. |
| Generation Capacity LCR Multiple | K7 | The system avoided costs are from the CPUC 2016 Update. If the generation capacity costs in the update differ over the expected lifecycle of the DER, a value other than 1.0 can be entered to scale up or down the attributed generation capacity value. A value of 1.5 would increase the CPUC avoided generation capacity cost by 50%. Default is 1.0. |
| T&D Value Basis | E13 | Utilities have the choice in how to value peak reductions. "Requirement-based threshold" assigns value for the project area only if peak reduction is sufficient for deferral. For other affected areas, value is based on the percentage of the kW need that is met by the DER. The user can "exclude" other affected projects to force the attributed value to zero.<br><br>"Allocation-based average" is based on expected reductions and is not limited to discrete integer years of deferral. "Allocation-based average" calculates value using peak capacity allocation factors (see below for a description of PCAFs). |
| Include or Exclude Deferral Value | I24:I33 | The utility can choose to exclude other affected areas from the valuation by selecting the “Exclude” option. |
| Include Component | D41:D49 | Utilities can choose to exclude system avoided cost components by selecting the FALSE option. |
| Project Inputs & Avoided Costs | | |
| First load forecast year | C4 | This sets the first year of hourly peak/need information for all project areas. |
| Discount Rate | C5 | Utility WACC, nominal. The revenue requirement multiplier, equipment inflation rates, O&M inflation rates, and O&M factors may vary by discount rate, so this input may also affect the values that are used for those items. |
| Generic Default Inflation Rate | C6 | Used as the default for equipment and O&M annual inflation in the Settings tab. |
| Case to use | C8 | The LNBA tool allows for three sets of cost estimates to be entered into the model. This dropdown indicates which set should be used for the reported results on the DER Dashboard tab. |
| Project information | | |
| Location identifier | Row 18 | User Text |
| Location mapping | Row 19 | User Text |
| Equipment Type | Row 20 | Revenue requirement multipliers, equipment inflation rates, O&M inflation rates, O&M costs, and project lifetimes are stored in the LNGA tool according to Equipment Types. This selection indicates which set of values are used. |
| Capital Cost ($000) | Row 27 | Project capital cost. This value will be increased by the revenue requirement multipliers to convert the values to revenue requirement levels. |
| Cost Yr Basis | Row 29 | Indicates which year dollars are used for the Capital Cost inputs. The Capital Costs are inflation adjusted as needed based on this Cost Yr entry. |
| Project install/commitment | Row 30 | Used to determine ability of DER to defer the project. Projects with install/commitment years before the DER Install Yr are excluded from |

| | | |
|---|---|---|
| year | | the valuation. |
| Project Flow Factors | E49:X10 | For each DER installation location (Column C), the utility should enter each other project that can be affected by DER installed at that location. Along with the identification, a flow factor should be entered to indicate how the DER would affect each project. The default flow factor is 100%, indicating a 1kW reduction in net demand in the installation area would translate to a 1kW reduction in the other affected area. A value of 50% indicates that the other affected area would only see half of the kW impact of the installation area. |
| Loss Factors | E64:X72 | In this section, the utility enters the loss factors from the DER installation to the constrained utility equipment for the DER installation area and any other affected projects. |
| Area Peaks | | |
| Starting date and time | B16 | Enter the timestamp for the start of the hourly information. The utility can enter ten years of hourly data for each project to reflect are growth and usage changes, but all of the input data for all projects should match the weather and chronology indicated by this timestamp. For example, if the first 24 hours are for a Wednesday in the first year, all years should start with on a Wednesday. Furthermore if a heatstorm occurred on August 20$^{th}$ – 23$^{rd}$ in the first year, the loads for all other years should also reflect a heat storm on August 20$^{th}$ – 23$^{rd}$. |
| Area Peak / Need (kW) | Rows 16:8775 | Enter the project area kW demand or kW need for each hour. |
| Threshold | Row 13 | If an area has kW demand entered, a threshold can be input in this row to define the peak hours. Peak hours will consist of all hours with demand above the threshold. If a value of zero is input as the threshold, all hourly inputs above zero will define the peak period. |
| SystemAC | | |
| | | This tab contains the CPUC 2016 Update hourly avoided costs. (based on 2015 conditions and chronology) This will not need revision for Demo B, but could be updated in the future as needed for new system avoided costs. |
| Flex RA | | |
| Integration Cost Adder ($/MWh) | D3:D5 | The entered values are from D.14-11-042. This should not need revision for Demo B. |
| Month | D7 | Month when the maximum need for ramp occurred in 2015. Used to define the hours of need for ramping. The choice of ramp year should match the year used for the system avoided costs |
| Day | D8 | Day of the month when the maximum need for ramp occurred in 2015. |
| End of hour interval before ramp starts | D9 | Defines when maximum need for ramp occurred in 2015. |
| Flex RA Value ($/kW-yr) | Row 12 | Annual flexible resource adequacy value in $/kW-yr. |
| Remapping | | |
| Season definitions | D4:D15 | Enter a value from 1 to 4 for each month to define up to four seasons. Days will be binned according to these seasons, and days will not be allowed to cross seasons in the remapping process. |
| Metric to Use | H4 | Select whether to use the Min/Max metric or the 3-day weighted average metric for the remapping rankings. |
| 3-Day temp metric settings | H8:H10 | If you are using the 3-day metric, enter the weight you would like to assign to each day's average temperature. |
| Remap system costs? | H12 | Set to FALSE to keep system avoided costs in original 2015 order. Default is TRUE. |
| Settings | | |
| Discount Rates | C7:E7 | Note that these are NOT used for discounting in the LNBA Tool. The |

| | | |
|---|---|---|
| | | tool allows multipliers and escalation rates to be linked to discount rates. These three cells define the three sets of multipliers and escalation rates. The discount rates should be entered in ascending order from left to right, to be compatible with the interpolation routines used in the tool. |
| Revenue Requirement Multiplier | C13:E28 | Used to scale project costs to revenue requirement levels. Enter multipliers corresponding to the three discount rate sets. If the active discount rate entered in the Project Inputs & Avoided Costs tab does not match one of the discount rate sets, the tool will interpolate if the active discount rate is between two sets, or use the lowest or highest set values. The tool will not extrapolate values. |
| Inflation Rates | F13:K28 | The inflation rates are set to the default generic inflation rate entered in the Project Inputs & Avoided Costs tab, but can be manually overwritten. |
| Book Life | L13:L28 | The book life of the equipment type. This is used by the RECC formula to determine the annual deferral value for the equipment. |
| O&M Factor | M13:O28 | Multiplied by the project cost (before revenue requirement multiplier) to define the annual incremental O&M cost for the project. |
| Default Loss Factor | C30 | This value is used to avoid division by zero errors if a loss factor for a project has been not been entered. |
| Default Flow Factor | C31 | This value is used to avoid division by zero errors if a flow factor for a project has not been entered. |
| Dashboard Selection, etc | Column S | Used for dropdown choices in the tool. Do not edit. |

# 3. Methodology

## 3.1 Deferral Value and Avoided Costs

### *Potential Deferral Value (DefValTotPot[p,a]) ($)*

Potential deferral value is the present value (in the DER install year) of capital and O&M deferral savings over the period of the DER install year up to, but not including the "Defer T&D to this Year."

DefValTotPot[p,a] = DefValCap[p,a] + DefValOM[p,a]

### *Deferral value of capital project (DefValCal[p,a]) ($)*

DefValCal[p,a] is the present value of capital deferral savings. The savings is for all projects (p) that are affected by DER installed in area (a).

$$DefValCal[p,a] = \sum_{all\ projects} [DefValCap[p]\ that\ can\ be\ deferred\ by\ DER\ in\ location\ "a"]$$

where

$$DefValCal[p] = \sum_{yr=1}^{DefInstallYr-InstallYr} \left[\frac{Inv[p] * RRMult * RECC * (1 + esc[Inv])^{yr-1}}{(1 + disc)^{yr-1}}\right]$$

where

| | | |
|---|---|---|
| Inv[p] | = | The capital investment adjusted to the nominal year dollars of the DER install yr (adjusted by equipment-specific inflation factors) |
| | = | TDCapital *(1+esc[Inv])^(InstallYr – TDCostYr) |
| Esc[Inv] | = | annual escalation rate for the investment equipment type |
| InstallYr | = | Year the DER is to be installed under the base plan |
| DefInstallYr | = | Year the project will be built after deferral (*Defer T&D to this year* input). For example, if the InstallYr is 2017, and the project will be deferred three years, the DefInstallYr is 2020 |
| TDCostYr | = | The base year for the project cost estimate (nominal costs in this year's dollars) |
| RRMult | = | Revenue requirement multiplier that adjusts the engineering cost estimate for the capital project to total revenue requirement cost levels. The adjustment reflects cost increases from factors such as corporate taxes, return on and of investment, property taxes, general plant, and administrative costs. |
| RECC | = | Real economic carrying charge. RECC converts capital cost into an annual investment cost savings resulting from a discrete period of deferral. The formula is shown below where r is the nominal discount rate, i is inflation, and n is the lifetime of the capital project. |

$$RECC = \frac{(r-i)}{(1+r)} \frac{(1+r)^n}{[(1+r)^n - (1+i)^n]}$$

### *Deferral value of avoided incremental O&M (DefValOM[p,a]) ($)*

| | | |
|---|---|---|
| DefValOM[p,a] | = | Present value of the incremental O&M that would be avoided by project deferral. The O&M is for all projects (p) that are affected by DER in area (a). The O&M is escalated each year by the O&M inflation rate, and discounted to present value dollars using the utility discount rate. |

$$DefValOM[p,a]) = \sum_{yr=1}^{DefinstallYr-InstallYr} Inv[p] * OMFctr[p] * (\frac{1+OMesc[inv]}{1+r})^{yr-1}$$

Where

| | | |
|---|---|---|
| OMFctr[inv] | = | O&M Factor for the investment type |
| OMesc[inv] | = | O&M escalation rate for the investment type |

### *Lifecycle value for system components (LifeCycleValue)*

Present value benefits of the DER over its useful life. Energy, Gen Capacity, Ancillary Services, CO2, and RPS are based on the CPUC 2016 Avoided Cost Update hourly values, and use the formula below:

$$LifeCycleValue = \sum_{yr=installYr}^{installYr+EUL-1} \left[ \frac{\sum_{hr=1}^{hr=8760} SystVal[c,yr,h'] * DERkW[h]}{(1+r)^{yr-1}} \right] + \text{IntegValue} + \text{TValue}$$

Where

| | | |
|---|---|---|
| SystVal[c,yr,h'] | = | System avoided cost in $/kWh for component c, in year yr, and hour h'. |
| c | = | the avoided cost component. Energy, Gen Capacity, Ancillary Services, CO2, and RPS are from the CPUC avoided cost model. Avoided costs are at the secondary voltage level and already reflect losses. |
| SystVal[flex,yr,h'] | = | System avoided cost for flexible capacity value |
| | = | FlexRACap[yr] *FlexRAAlloc[h'] |
| FlexRACap[yr] | = | Flexible RA Capacity value in $/kW (utility input on Flex RA tab) |
| FlexRAAlloc[h'] | = | Hourly allocation factor for ramping, remapped to match weather and chronology of Local T&D area peak loads and weather. The allocation factor assigns a value of 100% to Nov 16, 2015 hour ending at 6pm, and negative 100% to Nov 16, 2015 hour ending 3pm. The net effect is a Flex RA capacity benefit for reduced ramp (6pm demand being lower than 3pm demand.) Note that the day may be moved to align 2015 conditions with local T&D conditions (see description of h'). |
| f | = | Nominal utility discount rate |
| h | = | hour |
| h' | = | hour index, remapped to align 2015 system weather and weekday/weekend chronology to better match the weather and chronology of the local T&D hourly area peak/need. |
| EUL | = | Expected useful life of the DER in years (user input) |
| IntegValue | = | Present value of annual DER kWh output multiplied by the integration cost in cell K4, divided by 1000 (as the integration cost is in $/MWh). Discounting is done at the utility nominal discount rate. |
| TValue | = | System transmission capacity value is the input from Cell K6 multiplied by the DER maximum output. |

## 3.2 Calculation of Project Need and DER Peak Reduction

### *Need after Dependable DER (Need_after_DER[p])*

The kW needed after subtracting dependable DER load reductions.

Need_after_DER[p] = Max(AreaLoad[p][y][h] – Threshold[p] – DERkW[h] *Dependability /LossFactor[p,a] *FlowFactor[p,a])

Where

| | | |
|---|---|---|
| p | = | project |
| a | = | area where DER is installed |
| p,a | = | project area p, when DER is installed in area a. |
| AreaLoad | = | hourly project area load, or deficiency amount. |
| Threshold | = | kW above which there is an area deficiency. This entry is dependent on how the AreaLoad in input. In many cases the AreaLoad is entered as hourly deficiencies, in which case the Threshold would be zero. |
| DERkW[h] | = | DER reduction or output in each hour h. The output is before T&D losses |
| LossFactor[p,a] | = | Ratio of (1) DER impact at project p to (2) DER output in area a. |
| FlowFactor[p,a] | = | Derating factor if 1kW of DER demand reduction in area a does not translate to 1kW of demand reduction for project p. Default is 100% (no deration). If a value other than 100% is used, care should be taken to not double count impact reductions in the LossFactor. |
| Dependability | = | Dependability of DER is typically a low impact issue when looking at system-wide DER implementation because of the large diversity offered by large numbers of installations. Expected DER output is generally sufficient for estimating system-wide impacts. However, at smaller local distribution areas, the installations of DER will be smaller in number and the "safety" of the joint output of large numbers of devices will diminish. Therefore, the dependability of DER is a more important factor for smaller local distribution areas. In addition, DER that are weather dependent (such as PV) will be subject to common "failure" modes as the weather could impact all units in an area simultaneously. Therefore, the dependability of weather sensitive DER (both future and existing) is important as the penetration of those DER in an area increases. |

## *Dependable DER Reduction*

Dependable_DER_Reduction = kW_Needed[p] – Need_after_DER[p]

Where

kW_Needed[p] = Max over deferral years (AreaLoad[p][y][h] – Threshold[p])

## 3.3 Attributed Deferral Value

### *Attributed value for requirement-based threshold*

For the project where the DER is installed (row 22), the Attributed Deferral value equals the Potential Deferral value if the kW reduction is Sufficient for Deferral (Cell G22 = TRUE). Otherwise zero.

For other affected projects (rows 24 and below), the value is the Potential Deferral (Col H) value multiplied by the ratio of the Dependable DER Reduction (Col F) divided by the kW Needed (Col D). The ratio is limited to not exceed 100%, and any project can be manually excluded by entering 'Excluded" in column I.

### *Attributed value for allocation-based average (AllocVal[a])*

*Value is based on expected reductions and is not limited to discrete integer years of deferral.*

The Attributed Deferral value is calculated using peak capacity allocation factors (PCAF)for each affected local T&D area.

$$AllocVal[a] = \sum_{h=1}^{8760} DERkW[h] * AllocTD[a][h]$$

Where

| | | |
|---|---|---|
| DERkW[h] | = | DER reduction or output in each hour h. The output is before T&D losses |

$$AllocTD[a][h] = \sum_{all\ affected\ p} TDperkW[p] * LossFactor[p,a] * FlowFactor[p,a] * PCAF[p,yr,hr]$$

| | | |
|---|---|---|
| TDperkW[p] | = | DefValCap[p]/ Need[p][DeferedYr-1] |
| Need[p][DeferedYr-1] | = | Total peak reduction need (kW) for project p in the last year to be deferred. |
| LossFactor[p,a] | = | Ratio of (1) DER impact at project p to (2) DER output in area a. |
| FlowFactor[p,a] | = | Derating factor if 1kW of DER demand reduction in area a does not translate to 1kW of demand reduction for project p. Default is 100% (no deration). If a value other than 100% is used, care should be taken to not double count impact reductions in the LossFactor. |
| PCAF | = | Peak capacity allocation factor to assign relative weights to each hour in the peak period. The sum of the PCAFs for any year sum to 1.0. |

$$PCAF[p,yr.h] = \frac{Max(0, Load[\mathrm{p,yr,h}] - Thresh[\mathrm{p}])}{\sum_{hr=1}^{8760} Max(0, Load[p,yr,h] - Thresh[p])}$$

| | | |
|---|---|---|
| Load[p,yr,h] | = | Hourly load or need in the project area, in the year. |
| Thresh[p] | = | Threshold for defining the peak hours for the project area. If the Load represents need, then Thresh would be zero. Otherwise all hours with load above Thresh would be considered peak hours. |

### *Hourly Local T&D Costs (HourlyTD[a][h], HourlyTDAll[a][h])*

Deferral value allocated to hours of the year based on the hourly PCAFs. Shown in N57:O8816 of the DER Dashboard.

| | | |
|---|---|---|
| HourlyTD[a][h] | = | Hourly local T&D costs for the project area where DER would be installed |
| | = | DefValCap[a] * AllocTDI[a][h] |
| HourlyTDAll[a][h] | = | Hourly local T&D Costs for all projects affected by DER in area a, that have not been explicitly excluded. |
| | = | Sum of all DefValCap[p,a] * AllocTD[p][h] |

## 3.4 Other

### *Remapping process (h')*

We expect that local area peak or need hourly information may be based on a year that differs from the 2015 year used for the CPUC system avoided cost development. To accommodate differing base years, the LNBA tool remaps days to better align the system avoided costs and local T&D peak/need (DER shapes are assumed to match the local T&D peak/need year). To do this, the LNBA tool calculates a temperature metric to rank days within user specified seasons, and recognizing weekdays and weekend/holidays.

The system avoided cost information is based on 2015. For discussion purposes, assume the local T&D hourly area peak/load information is for 2013. The remapping process follows the following process

1. Calculate peak temperature metrics for each day based on daily temperature information (min temp, max temp, average temp). The metric can vary by utility, and is meant to reflect weather conditions that drive peak usage (e.g.: heat storms, lack of evening cooling, etc). There are two temperature metric options in the tool

   a) The three-day weighted average metric equals 60% of the current day average temperature plus 20% of the prior day average temperature plus 10% of the average temperature for two days prior.

   b) The Min and Max temperature metric equals (0.7 x max) + [(0.003 x min) x (max-1)] + [(0.002 x (min-1)) x (max-2)]

2. Define up to four seasons (assign months to seasons)

3. Classify each day in 2015 and 2013 to "bins" defined by weekdays/weekend-holiday/season.
4. Rank the 2015 and 2013 days in each bin in descending order of the temperature metric.
5. For each bin (workday/weekend-holiday, season), map the highest ranked temperature metric day for 2015 to the highest ranked temperature metric day for 2013. Map the second highest 2015 day to the second highest 2013 day, etc. If there are more 2015 days in the bin than 2013 days, the lowest ranked 2015 days would be discarded. If there are fewer 2015 days in the bin than 2013 days, the lowest ranked 2015 day would be replicated as needed.
6. Assemble a new 8760 of system avoided costs (2015 original basis) that now reflect a 2013 basis, using the day mapping from above, and calibrate the total over the year so that the sum of the remapped avoided costs matches the original avoided costs.
   6.1. For Flex RA, the sum of the absolute values is used for calibration because the simple summation totals zero. If the ramp day is discarded during the remapping process, errors will be returned. In that case, an alternate ramp day should be designated in the Flex RA tab.

# Appendix 3: ACR to Final Documents Table

| Requirement | ACR Description | ACR | Document | Location in Document |
|---|---|---|---|---|
| DPA Selection/Projects for Deferral | In selecting which DPA to study, the IOUs were instructed to, at minimum, evaluate one near-term (0-3 year project lead time) and one longer-term (3 or more year lead time) distribution infrastructure project for possible deferral. This guidance ruling expands the scope of the Demonstration Project B to require demonstration of at least one voltage support/power quality- or reliability/resiliency-related deferral opportunity in addition to one or more capacity-related opportunities. Both types of opportunities may be located in the same DPA, but if the DPA selected by any IOU does not include noncapacity-related opportunities, the IOU must evaluate a noncapacity project in another DPA. | 4.1; pg. A24 | Final Report | Chapter 4.1 |
| LNBA Methodology Requirements | The approach is to specify a primary analysis that the IOUs shall execute and a secondary analysis that the IOUs may execute in addition to the required analysis. Consistent with the Roadmap staff proposal, the primary analysis shall use DERAC values, if available, for system-level values. For the primary analysis, the IOUs are directed to develop certain system-level values that are not yet included in the DERAC (e.g., Flexible RA, renewables integration costs, etc.) to the extent feasible. | 4.3; pg. A26-A28 | Final Report | Chapters 8, 9, Appendix 2 |
| Table 2 | Primary Analysis | 4.3; pg. A27-A28 | Final Report | Chapter 2.1 |
| LNBA Specific Requirements | | | | |
| Project Identification | The IOUs shall identify the full range of electric services that result in avoided costs for all locations within the DPAs selected for analysis. The values shall include any and all electrical services associated with distribution grid upgrades | 4.4.1 (1)(A); pg. A29 | Final Report, Downloadable Dataset | Final Report - Chapters 5, 6, 7; Downloadable Dataset - 'Deferrable Project Data' tab, 'Non |

| | | | | |
|---|---|---|---|---|
| | identified in (i) the utility distribution planning process, (ii) circuit reliability improvement process and (iii) maintenance process. | | | Deferrable Project Data' tab |
| List of Locations for Projects | Develop a list of locations where upgrade projects, circuit reliability, or maintenance projects may occur over each of the planning horizons to the extent possible | 4.4.1 (1)(B)i; pg. A29 | Final Report, Downloadable Dataset | Final Report - Chapters 5, 6, 7; Downloadable Dataset - 'Deferrable Project Data' tab |
| Cost of Projects | Use existing approaches for estimating costs of required projects identified | 4.4.1 (1)(B)ii; pg. A29 | Final Report | Final Report - Chapters 5, 6, 7 |
| Time Horizon of System Upgrade Needs | System upgrade needs identified in the processes should be in three categories that correspond to the near term forecast (1.5 – 3 year), intermediate term (3-5 year) and long term (5-10 year) or other time ranges, as appropriate and that correspond to current utility forecasting practice. A fourth category may be created employing “ultra-long-term forecast” greater than 10 years to the extent that such a time frame is supported in existing tools. | 4.4.1 (1)(B)iii; pg. A29 | Final Report, Downloadable Dataset | Final Report - Chapters 5, 6, 7; Downloadable Dataset - 'Deferrable Project Data' tab |
| List of Electric Services from Projects | Prepare a location specific list of electric services associated with the planned distribution upgrades, and present these electric service needs in machine readable and map based formats. | 4.4.1 (1)(B)iv; pg. A30 | Downloadable Dataset | Downloadable Dataset - 'Deferrable Project Data' tab |
| DER capabilities to provide Electric Services | For all electrical services identified, identify DER capabilities that would provide the electrical service. As a starting point, consider all DER derived from standard and ‘smart’ inverters and synchronous machines. | 4.4.1 (1)(B)v; pg. A30 | Final Report | Chapters 3.1, 3.2, 3.3 |
| Specifications of System Upgrade Needs | A description of the various needs underlying the distribution grid upgrades; Electrical parameters for each grid upgrade including total capacity increase, real and reactive power management and power quality requirements; An equipment list of components required to accomplish the capacity increase, maintenance action or reliability improvement; | 4.4.1 (1)(B)vi(a-d); pg. A30 | Final Report, Downloadable Dataset | Final Report - Chapters 5, 6, 7; Downloadable Dataset - 'Deferrable Project Data' tab, 'Deferral Requirement Profile' tab |

| | | | | |
|---|---|---|---|---|
| | Project specifications for reliability, maintenance or capacity upgrade projects identified by the utilities shall include specifications of the following services as applicable: Voltage Control or Regulation, Reactive Supply, Frequency Regulation, Other Power Quality Services, Avoided Energy Losses, Equipment Life Extension, Improved SAIFI, SAIDI and MAIFI results | | | |
| Compute Avoided Cost | Compute a total avoided cost for each location within the DPA selected for analysis using the Real Economic Carrying Charge method to calculate the deferral value of these projects. Assign these costs to the four avoided cost categories in the DERAC calculator for this location. Use forecast horizons consistent with the time horizon above. | 4.4.1 (1)(B)vii(a-c); pg. A31 | LNBA Tool | LNBA Tool - 'Project Inputs & Avoided Costs' tab, Line 110 |
| Distribution System Services - Conservation Voltage Reduction and Volt/VAR optimization | To the extent that DER can provide distribution system services, the location of such needs and the specifications for providing them should be indicated on the LNBA maps. This analysis shall include opportunities for conservation voltage reduction and volt/VAR optimization. Additional services may be identified by the Working Group. | 4.4.1 (1)(C); pg. A31 | Final Report | Chapter 3.2.1 |
| Transmission CapEx | For avoided costs related to transmission capital and operating expenditures, the IOUs shall, to the extent possible, quantify the co-benefit value of ensuring (through targeted, distribution-level DER sourcing) that preferred resources relied upon to meet planning requirements in the California ISO's 2015-16 transmission plan, Section 7.3, materialize as assumed in those locations. The IOUs shall provide work papers with a clear description of the methods and data used. If the IOUs are unable to quantify this value, they should use the avoided transmission values in the Net Energy Metering (NEM) Public Tool developed in R. 14-07-002.44 | 4.4.1 (2) + (A); pg. A31-A32 | Final Report; LNBA Tool | Final Report - Chapter 8.3; LNBA Tool - 'DER Dashboard' K6 |

| | | | | |
|---|---|---|---|---|
| Line Losses | For the secondary analysis, use the DERAC avoided capacity and energy values modified by avoided line losses may be based on the DER's specific location on a feeder and the time of day profile (not just an average distribution loss factor at the substation).45 The IOUs shall provide a clear description of the methods and data used. | 4.4.1 (3); pg. A32 | N/A | N/A, Demo B LNBA Methodology focuses on the Primary Analysis in Table 2 of the ACR only. |
| Flexible Generation | For the avoided cost of generation capacity for any DERs which provides flexible generation, the IOUs shall apply a method, such as the "F factor" which has been proposed for the Demand Response Cost-effectiveness Protocols.46 The IOUs shall provide work papers with a clear description of the methods and data used. | 4.4.1 (4); pg. A32 | Final Report | Appendix 2 |
| Avoided Energy - LMPs | For the secondary analysis, the IOUs may also estimate the avoided cost of energy using locational marginal prices (LMPs) for a particular location, as per the method described in SCE's application. The IOUs shall provide work papers with a clear description of the methods and data used. | 4.4.1 (5); pg. A32 | N/A | N/A, Demo B LNBA Methodology focuses on the Primary Analysis in Table 2 of the ACR only. |
| Avoided Costs - Renewable Integration, Societal, and Public Safety | If values can be estimated or described related to the avoided costs of renewable integration, societal (e.g., environmental) impacts, or public safety impacts, the IOUs shall propose their methods for including these values or descriptions in the detailed implementation plans | 4.4.1 (6); pg. A32-A33 | Final Report | 9.6 and 9.7 |
| Methodology Description | The IOUs shall provide detailed descriptions of the method used, with a clear description of the modeling techniques or software used, as well as the sources and characteristics of the data used as inputs. | 4.4.1 (7); pg. A33 | Final Report | Appendix 2 |
| Software and Data Access | The IOUs shall provide access to any software and data used to stakeholders, within the limits of the CPUC's confidentiality provisions. | 4.4.1 (8); pg. A33 | Final Report | 2.3-2.4; LNBA Tool will be released, Heat Maps will be publicly available |

| | | | | |
|---|---|---|---|---|
| DER Load Shapes and Adjustment Factors | Both the primary and secondary analyses should use the load shapes or adjustment factors appropriate to each specific DER. | 4.4.1 (8); pg. A33 | Final Report | Appendix 2 |
| Other Related LNBA Requirements | | | | |
| Heat Map | The IOU's LNBA results shall be made available via heat map, as a layer along with the ICA data in the online ICA map. The electric services at the project locations shall be displayed in the same map format as the ICA, or another more suitable format as determined in consultation with the working group. Total avoided cost estimates and other data may also be required as determined in the data access portion of the proceeding. | 4.4.2 (1); pg. A33 | Final Report | 2.4, Appendix 1 |
| DER Growth Scenarios | The IOUs shall execute and present their LNBA results under two DER growth scenarios: (a) the IEPR trajectory case, as filed in their applications (except that PG&E shall conform its PV forecast to the IEPR base case trajectory); and (b) the very high DER growth scenario, as filed in their applications. The DER growth scenario used in the distribution planning process for each forecast range should be made available in a heat map form as a layer in conjunction with the ICA layers identified earlier. | 4.4.2 (2) + (a); pg. A33 | Final Report | 4.3 |
| General Requirements | | | | |
| Equipment Investment Deferral | The IOUs shall identify whether the following equipment investments can be deferred or avoided in these projects by DER: (a) voltage regulators, (b) load tap changers, (c) capacitors, (d) VAR compensators, (e) synchronous condensers, (f) automation of voltage regulation equipment, and (g) voltage instrumentation. | 5.1 (C); pg. A34 | Final Report, Downloadable Dataset | Final Report - Chapters 5, 6, 7; Downloadable Dataset - 'Deferrable Project Data' tab |

| | | | | |
|---|---|---|---|---|
| Implementation Plan | The IOUs shall submit detailed implementation plans for project execution, including metrics, schedule and reporting interval. To the extent practicable, the IOUs shall consult with the LNBA working group on the development of the plan. The plan shall be submitted to the CPUC within 45 days of this ruling. The implementation plan shall include: A detailed description of the revised LNBA methodology; A description of the load forecasting or load characterization methodology or tool used to prepare the LNBA; A schedule/Gantt chart of the LNBA development process for each utility, showing: Any external (vendor or contract) work required to support it; Additional project details and milestones including, deliverables, issues to be tested, and tool configurations to be tested; Any additional resources required to implement Project B not described in the Applications | 5.1 (d) + (i-iii); pg. A34-A35 | Implementation Plan - Done | See SCE's Implementation Plan |
| Reporting | A plan for monitoring and reporting intermediate results and a schedule for reporting out. At a minimum, the Working Group shall report out at least two times over the course of the Demonstration B project: 1) an intermediate report; and 2) the final report. | 5.1 (d)(iv); pg. A35 | Implementation Plan - Done | See SCE's Implementation Plan |