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CONSULTANT REPORT

San Joaquin Valley Distributed Energy Resource

Regional Assessment

Prepared for: **California Energy Commission**
Prepared by: **Navigant Consulting, Inc.**

NAVIGANT

California Energy Commission

Edmund G. Brown Jr., Governor

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ABSTRACT

This is the second study done in partnership with Southern California Edison evaluating the impacts of distributed energy resources on the utility electricity system. The first study evaluated impacts at the system level. This study evaluated impacts at a regional level. An upcoming study will evaluate impacts at a feeder level.

This Phase II study leverages the analytical framework demonstrated in Phase I to further explore the impacts, benefits, and costs of distributed energy resources in the San Joaquin Valley region of Southern California Edison's system. The study assessed the ability of distributed energy resources (DER, that is, distributed generation, energy efficiency, demand response, energy storage, and electric vehicles) to meet forecasted load growth and reliability needs, as well as the potential interconnection and integration costs to the transmission and distribution systems in the region.

The study found that optimized location and timing of distributed energy resources could lead to net benefits greater than $300 million, caused primarily by the deferral of transmission system investments. The key driver for the potential transmission system deferral was the assumption of whether California's persistent drought would necessitate certain transmission investments that DER could avoid or defer. Furthermore, the study found that energy storage and advanced inverters can reduce interconnection costs associated with some types of DER, improving the overall value to the distribution system.

Keywords: Distributed energy resources, San Joaquin Valley region, distribution, transmission, integration costs, economic analysis, distributed solar, energy storage, advanced inverters

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EXECUTIVE SUMMARY

The California Energy Commission's ongoing assessment of distributed energy resources (DER), such as distributed generation and small-scale energy storage, is providing needed insights that inform its responsibility as the state's primary energy policy and planning agency. The assessment includes a series of reports designed to help the Energy Commission address questions related to the impact of integrating DER in California, a complex issue given the interests and priorities of various stakeholders and the range of costs and benefits to the electric power grid

The Energy Commission published the first report (Phase I) in September 2014 that assessed the costs and impacts of integrating high penetrations of distributed generation in Southern California Edison's service territory. The study came in response to Governor Brown's goal of 12,000 megawatts of clean, local resources statewide by 2020 and found that utility system integration costs are driven largely by distributed generation location, for example, urban areas versus rural areas.

Presented in this report are the results of the second phase of this effort (Phase II), which assessed a broader set of DER and a more rigorous evaluation of interconnection costs and benefits. The Energy Commission retained Navigant Consulting, Inc. to assist in the Commission's evaluation of DER impacts and locational benefits, including DER impacts on individual feeders and the local transmission network.

Study Objectives and Scope

This study analyzes the impacts and associated costs and benefits of integrating high penetrations of DER in the San Joaquin Valley region of Southern California Edison's service territory. The study addressed DER impacts on the region's transmission and distribution systems, as well as bulk assets under California Independent System Operator control.

Specific issues the Energy Commission assessed in this study include:

- The cost to interconnect large amounts of DER in a defined planning area.
- The benefits DER can provide to an electric utility's transmission and distribution system.
- An examination of how targeting DER to specific segments of the transmission and distribution system can enhance DER value.
- The impact of a broader range of DER technologies and initiatives, including energy efficiency, demand response, energy storage, and electric vehicles on the transmission and distribution system.
- The role and capability of emerging technologies, such as advanced inverters and energy storage, to enable greater amounts and maximize the value of DER.

Energy Commission staff, in consultation with Southern California Edison, selected the San Joaquin Valley region for the DER pilot study. Within the identified locations, a detailed analysis was conducted to determine the suitability of each location to accommodate DER under various penetration scenarios.

For the San Joaquin Valley region, the Energy Commission sought to identify:

- Integration cost to accommodate DER under various penetration scenarios.
- Location and resource mixes that avoid or minimize integration costs, and/or identify the potential of DER to provide value to the system.

Distributed Energy Resource Scenarios and Case Studies

The study includes two 10-year DER growth scenarios for the San Joaquin Valley region, each structured consistent with Southern California Edison's July 2015 draft *Distribution Resource Plan*. It includes two distinct analyses. The first is an evaluation of DER benefits and costs at the distribution level, and the second at the transmission level. Each set of analyses evaluates a low and high amount of DER deployment, with a very high DER deployment sensitivity case at the transmission level. A critical aspect of the transmission level studies is declining availability of local hydroelectric generation due to the persistent drought, which has raised concerns by system planners that electric reliability in the region will degrade if hydroelectric sources are unable to generate electricity at historical levels. The study analyzed hydroelectric output at different levels in combination with varying amounts of DER.

The distribution and transmission studies evaluated two DER deployment scenarios. The first scenario is the "Business-as–Usual" case from the *Distribution Resource Plan*, which is based on the Energy Commission's *2013 Integrated Energy Policy Report* "Trajectory" Case. The second scenario is the "Very Aggressive" case from the *Distribution Resource Plan*, representing the highest level of DER capacity.

Table 1 presents the nameplate capacity and output at the time of combined electric distribution feeder peaks in the San Joaquin Valley region for specific DER technologies and programs under each of the two scenarios. There are just fewer than 250 feeders in the region.

Table 1: Nameplate DER Forecast for the San Joaquin Region

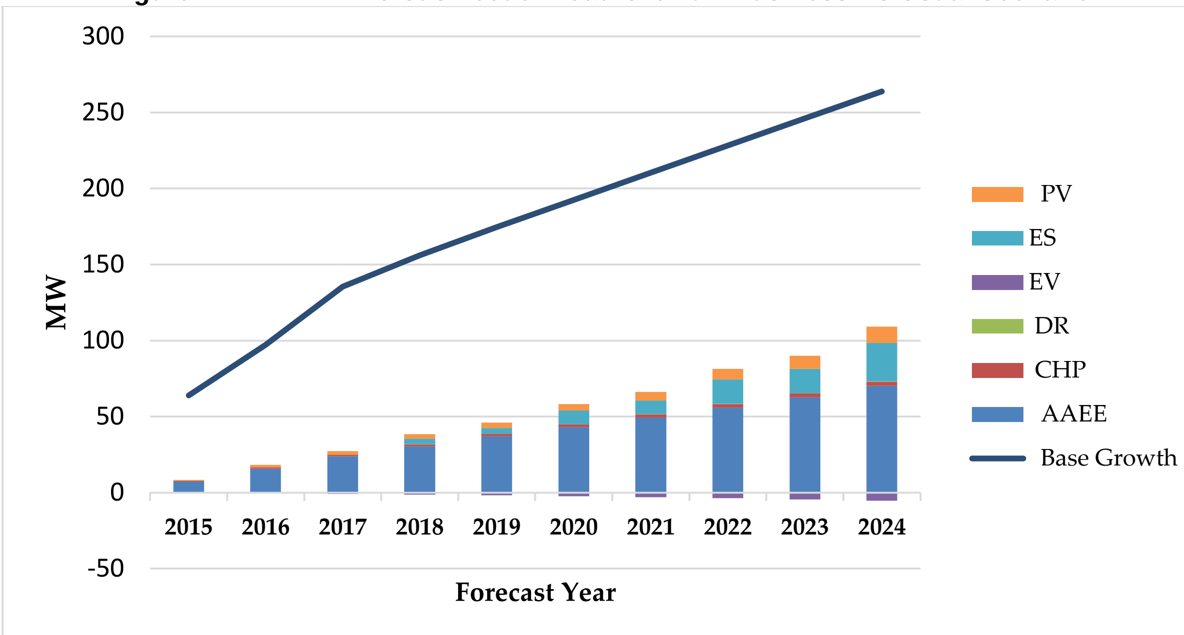
	BAU Scenario (MW)		VA Scenario (MW)	
DER Technology or Program	**Nameplate**	**Coincident With Feeder Peak Load**	**Nameplate**	**Coincident With Feeder Peak Load**
Additional Achievable Energy Efficiency (AAEE)	106.1	70.2	768	116.1
Photovoltaic (PV)	38.7	10.6	190.8	56
Combined Heat & Power (CHP)	4.6	2.8	51.6	31
Demand Response (DR)	2.8	0.1	156.5	4.4
Electric Vehicles (EV)	-7.0	-5.2	-15.3	-5.2
Energy Storage (ES)	25.4	25.4	56.3	56.3
Total	170.6	103.9	1207.9	258.6

Source: Navigant analysis of SCE data.

The amount of firm reliability capacity, or the amount available from each of these resources at the time of the transmission and distribution peaks, is lower than nameplate values due to factors such as peaks occurring at a time when solar output is low, or because energy efficiency includes devices and lighting that may not be operating.

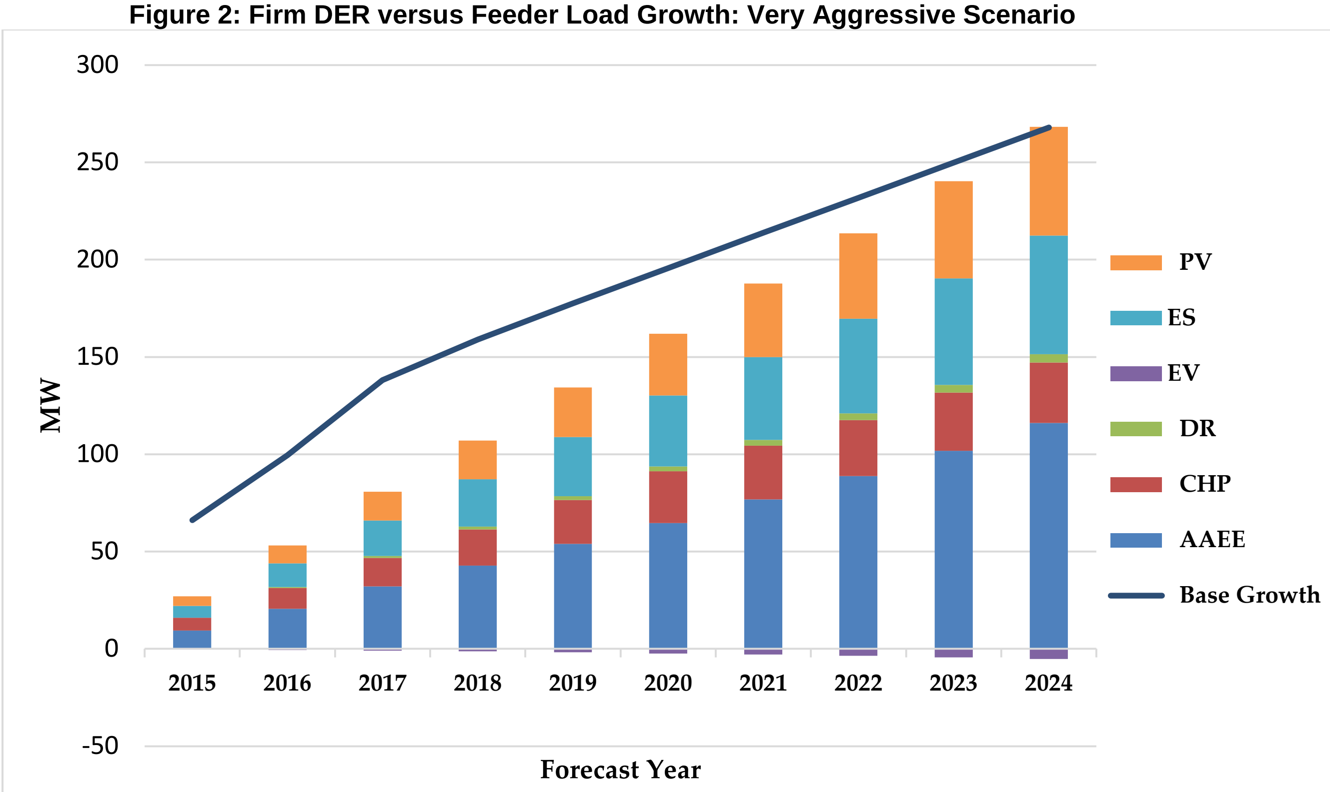
Figure 1 and **Figure 2** display the amount of firm DER capacity for the two scenarios versus incremental load growth in the region. The 2015 peak in the region was about 1,271 megawatts (MW) and is expected to increase at about 1.5 percent annually over the next 10 years.

Figure 1: Firm DER Versus Feeder Load Growth: Business As Usual Scenario



Source: Navigant analysis of SCE data.

Figure 2: Firm DER versus Feeder Load Growth: Very Aggressive Scenario



Source: Navigant analysis of SCE data.

The Energy Commission evaluated a combination of DER deployments for the Very Aggressive scenario, using advanced inverter technology and energy storage to reduce interconnection cost and increase benefits. Six cases were analyzed, summarized in **Table 2**.

Table 2: DER Case Studies

Case	Technology Description	Inverter Type	DER Scenario
1	Standard Inverters	Standard	Business as Usual
2	Standard Inverters	Standard	Very Aggressive
3	Advanced Inverters	Advanced	Very Aggressive
4	Advanced Inverters and Energy Storage	Advanced	Very Aggressive
5	Advanced Inverters With DER Targeted to Minimize Cost	Advanced	Very Aggressive
6	Advanced Inverters With DER Targeted to Maximize Benefits	Advanced	Very Aggressive

Source: Navigant analysis of SCE data.

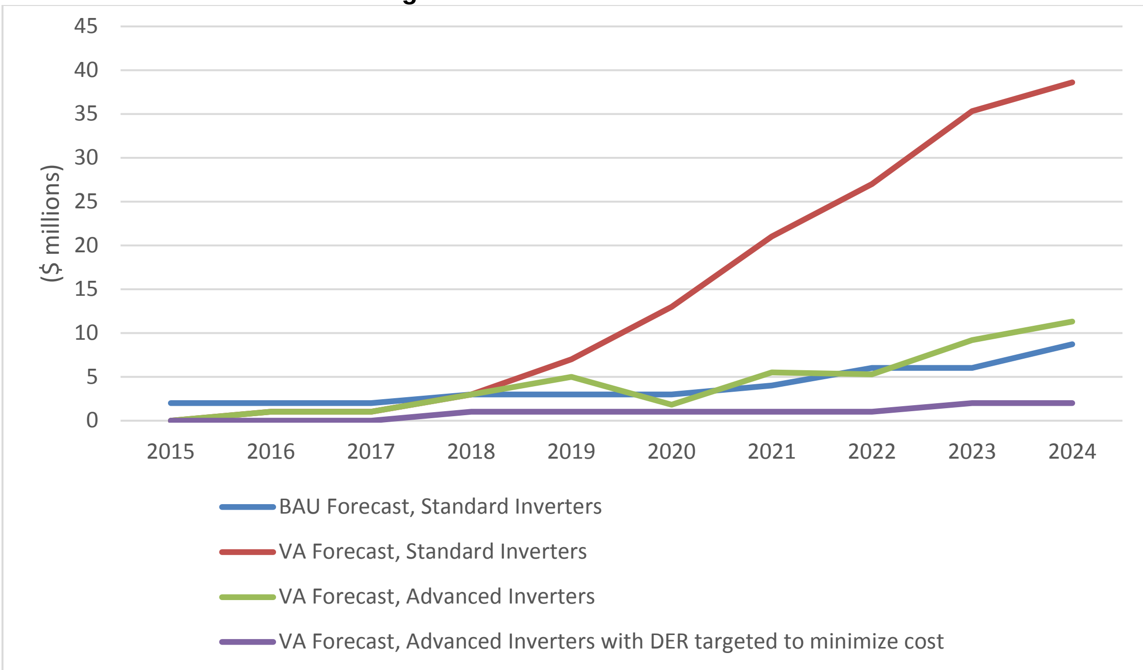
Distribution Results

The Energy Commission conducted studies for nine representative feeders located in the San Joaquin Valley region. These nine feeders represent all other feeders in the region. An industry-accepted approach similar to the evaluation framework in Phase I was used to statistically group more than 200 feeders located in the region into nine feeder clusters, from which one representative feeder was chosen to represent the entire cluster. Detailed simulation modeling studies were conducted on each of the representative feeders to predict impacts, including interconnection costs and benefits, for each of the six cases above. Cost curves that predict interconnection costs as a function of DER capacity were derived for each of the nine feeders. The amount of DER capacity projected over the next 10 years for the Business-As-Usual and Very Aggressive scenarios for each feeder was provided by Southern California Edison.

Interconnection Costs

Figure 3 presents cumulative interconnection costs (connection and system upgrades) for four of the cases presented above. The relatively low cost for the Business-As-Usual forecast case is due to the modest amount of DER capacity for (104 MW firm by 2024) versus area load (more than 1,300 MW), which results in few system upgrades.

Figure 3: Interconnection Costs



Source: Navigant

The cost of system upgrades increases significantly for higher amounts of DER capacity. The following summarizes the results of the aggressive forecast, standard inverters case (Case 2):

- System upgrade costs are low until 2018 but increase significantly thereafter for the standard inverter scenario.
- Most system upgrades occur on feeders in Cluster 6, which are longer, low-voltage (12.4 kilovolt [kV]) lines mostly in rural areas.
- Forty-eight out of 239 (roughly 20 percent) of distribution feeders are expected to incur system upgrade costs by 2024.
- Total interconnection costs (connection and system upgrades) range from a low of $2 million in 2015 to a high of $39 million in 2024.

Study results confirm that system upgrade costs can be reduced if advanced controls, such as voltage regulation, are applied to inverter-based DER, and further reduced when DER is located to avoid distribution system impacts, such as thermal overloads.

Distribution Benefits

The Energy Commission identified substation and feeder capacity deferrals as the primary benefit that DER can potentially provide. To predict benefits, the study conducted a capacity analysis consistent with Southern California Edison planning methods and criteria. An assumption was made that there must be enough firm DER capacity to reduce feeder peak loading to 90 percent of maximum normal rating. It was determined feeder capacity may be deferred from a low of one year to a maximum of 15 years, depending on future load growth and cumulative firm DER capacity. **Table 3** presents the results for each of the six case studies.

Table 3: 10-Year Cumulative Distribution Benefits by Case

Case	Description	Feeder Benefit	Transformer Benefit	Total Benefit
1	BAU Forecast, Standard Inverters	$0.1M	$0M	$0.1M
2	VA Forecast, Standard Inverters	$4.3M	$1.0M	$5.3M
3	VA Forecast, Advanced Inverters	$4.3M	$1.0M	$5.3M
4	VA Forecast, Advanced Inverters and Energy Storage	$9.1M	$1.1M	$10.2M
5	VA Forecast, Advanced Inverters With DER Targeted to Minimize Cost	$4.3M	$1.0M	$5.3M
6	VA Forecast, Advanced Inverters With DER Targeted to Maximize Benefits	$12.6M	$2.7M	$15.3M

Source: Navigant

Transmission Results

The transmission studies conducted for the Business-as-Usual and Very Aggressive DER scenarios confirm that DER may provide substantial long-term benefits depending on local hydroelectric conditions. Under normal water conditions – reservoir levels at the nearby Big Creek Hydroelectric plant return to historical levels – transmission impacts are minor and can be addressed using acceptable approaches. However, if the current drought persists, there will be insufficient generation in the San Joaquin Valley region, and short- and long-term upgrades will be needed.

Study results indicate that DER, if installed in sufficient amounts with sufficient lead time, could defer more than $300 million of 230 kV transmission upgrades beginning in 2025. Before 2025, short-term upgrades will still be required as sufficient amounts of firm DER will not be available to correct capacity deficiencies that exist today. Because the lead time for new transmission lines is between five and seven years, there would need to be firm commitments to install DER within the next few years in amounts sufficient for capacity deferral to realize benefits that begin after 2025.

Combined Transmission and Distribution Results

Table 4 summarizes transmission and distribution costs and benefits for each case based on the assumption that local hydroelectric reservoir levels will return to normal levels. Therefore, all transmission benefits in the table are attributed to reduced line losses since transmission capacity deferrals are not realized in normal hydroelectric generation years.

Table 4: Normal Hydro—10-Year Cumulative Net Benefits

Case	Description	Interconn Cost ($M)	Dist. Cap. Deferral ($M)	Trans. Cost ($M)	Net Cost($M)
1	BAU Forecast, Standard Inverters	$6.1	($0.1)	$3.4	$9.4
2	VA Forecast, Standard Inverters	$55.8	($5.3)	$3.4	$53.9
3	VA Forecast, Advanced Inverters	$16.7	($5.3)	$3.4	$14.8
4	VA Forecast, Advanced Inverters and Energy Storage	$37.0	($10.2)	$3.4	$30.2
5	VA Forecast, Advanced Inverters With DER Targeted to Minimize Cost	$14.2	($5.3)	$3.4	$12.3
6	VA Forecast, Advanced Inverters With DER Targeted to Maximize Benefits	$37.0	($15.3)	$3.4	$25.1

Source: Navigant

Table 5 illustrates that the above results could change significantly if the drought persists and firm DER was available in sufficient amounts with sufficient lead time. After 2025, net benefits associated with transmission deferral could range from $260 million and $320 million of 230 kV transmission upgrades beginning in 2025 and extending 10 to 20 years thereafter for the above six cases. Before 2025, short-term upgrades will still be required as sufficient amounts of firm DER will not be available to correct capacity deficiencies that exist today. Transmission savings include both line losses and capacity deferrals.

The amount of actual benefits also can vary depending on other factors, such as actual load growth in the region, hydroelectric generation output that may be between the low and high output cases, installation of new local generation, or new transmission construction by third parties. The latter two options could preclude transmission benefits associated with DER.

Table 5: Low Hydro—20-Year Cumulative Net Benefits

Case	Description	Interconn Cost ($M)	Dist. Cap. Deferral ($M)	Trans. Cost ($M)	Net Cost ($M)
1	BAU Forecast, Standard Inverters	$6.1	($0.1)	($352.9)	($346.9)
2	VA Forecast, Standard Inverters	$55.8	($5.3)	($352.9)	($302.4)
3	VA Forecast, Advanced Inverters	$16.7	($5.3)	($352.9)	($341.5)
4	VA Forecast, Advanced Inverters and Energy Storage	$37.0	($10.2)	($352.9)	($326.1)
5	VA Forecast, Advanced Inverters With DER Targeted to Minimize Cost	$14.2	($5.3)	($352.9)	($344.0)
6	VA Forecast, Advanced Inverters With DER Targeted to Maximize Benefits	$37.0	($15.3)	($352.9)	($331.2)

Source: Navigant

Summary

Study findings indicate interconnection costs for DER in the San Joaquin Valley region can be reduced by initiating several strategies. There are potential benefits that can further reduce net interconnection cost. Transmission benefits could be significant after 2024 if low hydroelectric generation output in the region continues and sufficient firm DER is available to defer transmission upgrades that may be needed if other competing options are not pursued.

Below are the related findings and conclusions for the distribution and transmission analysis:

Distribution

- The cost to interconnect DER ranges from zero to 10 percent of total installed cost of DER (up to $56 million for interconnection for Very Aggressive DER scenarios in 2024). Up to 20 to 40 percent of total interconnection cost is connection charges, which is nondeferrable.
- The interconnection cost for the Business-as-Usual DER scenario is less than 5 percent of total installed cost of DER, most of which is for connection, which is nondeferrable.
- The cost of upgrades can be reduced by 50 percent or more by implementing smart controls, such as voltage regulation, on all inverters or by targeting DER to feeders where the cost of system upgrades is low.
- Up to 75 percent of future distribution capacity upgrades can be deferred one year or more if energy storage is matched to solar devices or if DER is targeted to distribution feeders where benefits may be contingent upon other measures and investments outlined in Southern California Edison’s distribution resource plan.

Transmission

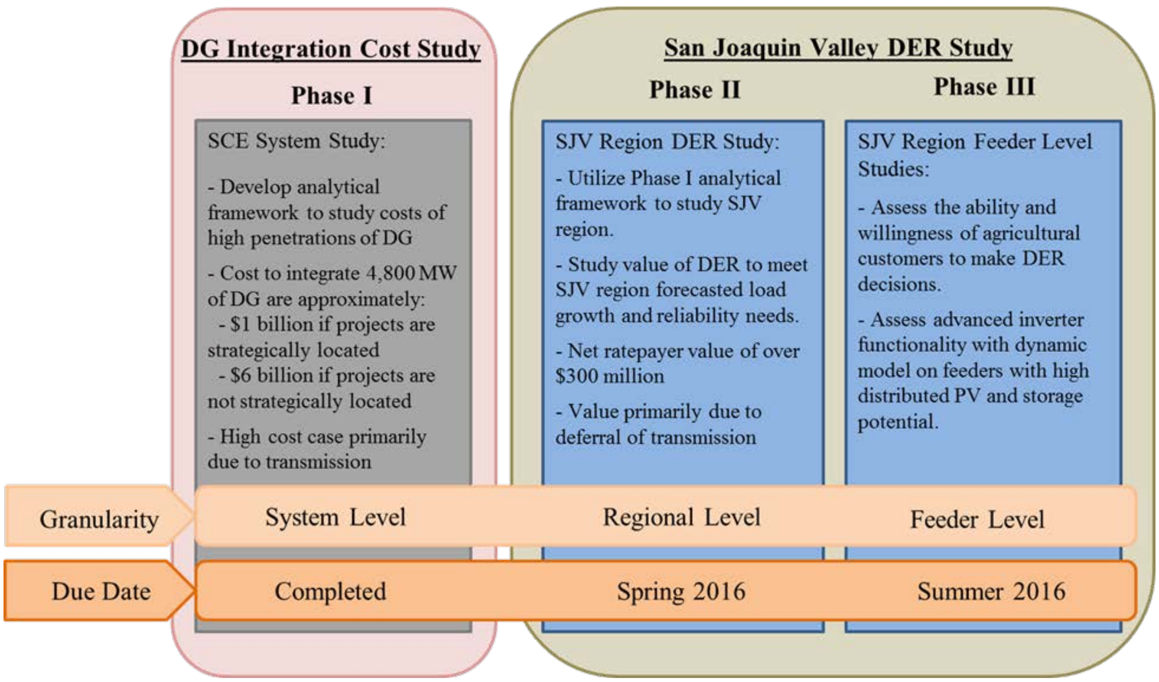
- The impacts of DER on the San Joaquin Valley region transmission system are modest if hydroelectric generation output at nearby hydroelectric power plants returns to normal levels after the current drought.
- Most impacts resulting from the presence of DER when hydroelectric generation output is at normal levels can be addressed by common mitigation options such as redispatching generation when outages or other emergencies occur.
- The transmission system may benefit from DER if hydroelectric output from the Big Creek plant continues to be low beyond 2024; these benefits may be substantial, if other mitigation options are not undertaken.
- More than $30 million in transmission capacity deferral may be achieved over 20 years if sufficient amounts of reliable DER capacity is available.

CHAPTER 1:
Introduction and Background

Background

The California Energy Commission is conducting an ongoing assessment of distributed energy resources (DER) providing needed insights that inform its responsibility as the state's primary energy policy and planning agency. The phasing of the DER assessment is illustrated in **Figure 4** and indicates a sequence of increasing study granularity.

Figure 4: Phasing of DER Assessments



Source: California Energy Commission

The Phase I study, published in September 2014, assessed the costs and impacts of integrating high penetrations of distributed generation (DG) in Southern California Edison's (SCE) service territory.[1] The study, done in partnership with SCE, came in response to the Governor's goal of 12,000 MW of DG statewide by 2020 and found that the cost of integrating high penetrations of DG on a utility's system was driven largely by location, for example, urban areas versus rural areas. Presented in this report are the results of the Phase II study that assessed a broader set of DER and a more rigorous evaluation of

1 California Energy Commission, *Distributed Generation Integration Cost Study: Analytical Framework*, September 2014.

interconnection costs and benefits. The Energy Commission retained Navigant to assist in the Commission's evaluation of DER impacts and locational benefits, including DER impacts on individual feeders and the local transmission network.

Study Objectives

This study is designed to help the Energy Commission address questions related to the impact of integrating DER in California, a complex issue given the interests and priorities of various stakeholders, and the range of costs and benefits to the electric power grid. The project team analyzed the impacts and associated costs and benefits of integrating high penetrations of DER in SCE's service territory and evaluated the related impact on SCE's transmission and distribution systems, and bulk assets under California Independent System Operator (ISO) control. The results from this analysis are intended to be shared with stakeholders to promote ongoing dialogue and analysis throughout the rest of the state on DER integration.

Specific questions the Energy Commission seeks to answer with this study include:

- How much it would cost to interconnect large amounts of DER in a defined planning area.
- What benefits can DER provide to an electric utility's transmission and distribution (T&D) system.
- How targeting DER to specific segments of the T&D system can enhance DER value.
- What is the impact of a broader range of DER technologies and initiatives, including energy efficiency, demand response, energy storage, and electric vehicles on the T&D system.
- What are the role and capability of emerging technologies such as advanced inverters and energy storage to enable greater amounts and maximize the value of DER.

Project Scope

Using the evaluation framework developed in Phase I, the Energy Commission staff, working with SCE, selected the San Joaquin Valley (SJV) region of SCE's service territory for the DER pilot study. Within the identified locations, the Energy Commission conducted a detailed analysis to determine the suitability of each location to accommodate DER under various penetration scenarios.

For the SJV region, the Energy Commission sought to identify:

- Integration cost to accommodate DER under various penetration scenarios.
- Locations and resource mixes that avoid or minimize integration costs, and/or identify the potential of DER to provide value to the system.

The Energy Commission's evaluation of DER has been underway for several years as part of a multiphase effort. The Phase II study quantifies interconnection costs and benefits (Phase I evaluated DG interconnection costs only) for a targeted region (San Joaquin Valley) on a more detailed level over a 10- and 20-year horizon. It also analyzes the role and potential benefits of emerging technologies, such as advanced inverters functions that were discussed by the Rule 21 Smart Inverter Working Group (SWIG).[2] Phase II also assesses dynamic impacts of variable output from renewable resources such as solar, as large amounts of renewable output potentially can impact power quality.

Distributed Energy Resource Scenarios and Case Studies

The study includes two 10-year DER growth scenarios for the SJV region, each structured consistent with SCE's July 2015 draft *Distribution Resource Plan* (DRP).[3] It includes two distinct analyses. The first is an evaluation of DER benefits and costs at the distribution level, and the second at the transmission level. Each set of analyses evaluates a low and high amount of DER deployment, with a very high DER deployment sensitivity case at the transmission level. A critical aspect of the transmission level studies is the availability of local hydroelectric generation, which the Energy Commission analyzed at different levels of output in combination with varying amounts of DER.[4]

The distribution and transmission studies evaluated two DER deployment scenarios. The first scenario is the Business-as-Usual (BAU) case from the DRP, which is based on the Energy Commission's *2013 Integrated Energy Policy Report* "Trajectory" Case. The second scenario is the "Very Aggressive" (VA) case from the DRP, representing the highest level of DER capacity

The Energy Commission evaluated a combination of DER deployments for the VA scenario, using advanced technology and energy storage to reduce interconnection costs and increase benefits. **Figure 5** presents the six case studies the Energy Commission developed for evaluation at the distribution level. The BAU scenario, which has lower DER capacity, includes a single case study—the Energy Commission surmised DER net benefits would be modest at lower capacity levels. The other five cases evaluate a combination of advanced

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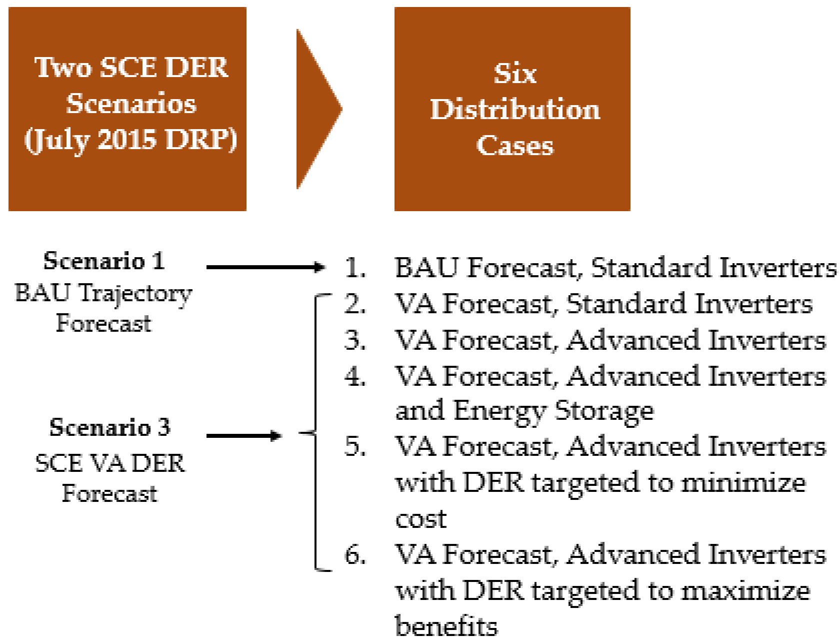
2 http://www.energy.ca.gov/electricity_analysis/rule21/

3 http://www.edison.com/content/dam/eix/documents/newsroom/news-releases/A15-07-XXX_DRP_Application_SCE_Application_and_Distribution_Resources_Plan_and_Appendices_A-J.pdf

4 The level at which local hydroelectric generation at Big Creek and other plants in the watershed north of San Joaquin Valley declined and is expected to continue to decline due to the persistent drought. Concerns have been raised by system planners that electric reliability in the region will degraded if hydroelectric sources are unable to generate electricity at historical levels in amounts sufficient to meet reliability performance requirements.

inverter control and storage options under the VA scenario. The amount of DER capacity assigned to each of the six cases is presented in Chapter 2. Chapter 3 presents the Energy Commission's evaluation of DER at the distribution level.

Figure 5: Distribution Case Studies



Source: Navigant

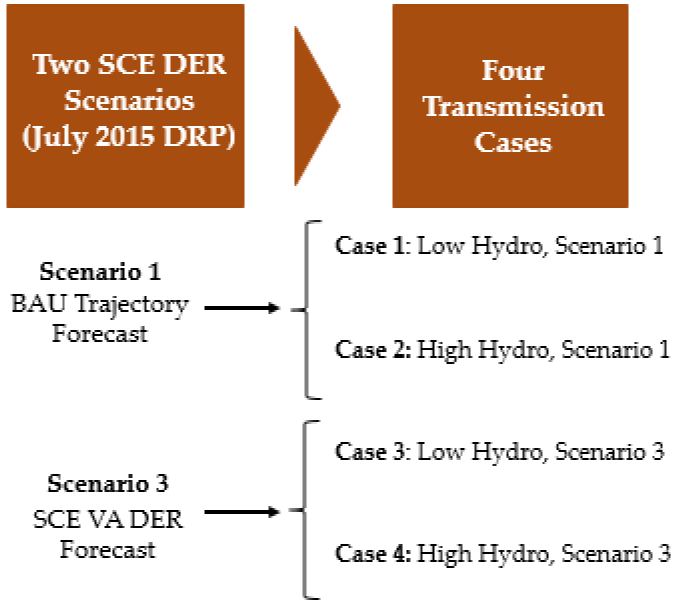
At the transmission level, the Energy Commission evaluated DER based on SCE's BAU and VA scenarios, but with case studies focusing on low and high hydroelectric output. **Figure 6** presents four cases studies the Energy Commission analyzed to assess DER impacts on the transmission system. Each of the case studies focuses on evaluating the impact of varying regional hydroelectric plant output, primarily from the Big Creek Hydroelectric Project (Big Creek) in Fresno County. As noted, drought conditions have reduced reservoir levels and associated output from plants within the watershed. Output from local hydroelectric resources at Big Creek and other nearby plants supports the transmission grid in the SJV region, and lower hydroelectric output, when combined with area load growth, may degrade transmission system reliability.

The addition of DER capacity in the SJV region may be a less expensive alternative than either conventional transmission expansion or system reinforcement options. Firm DER capacity is defined as the amount of DER output that is deemed available in sufficient amounts at the time of the feeder or transmission peak, or near peak, conditions, to be equivalent to conventional distribution upgrades such as new or upgraded lines and substation transformers.[5] Case studies include evaluation of BAU and VA DER scenarios for both low and high hydroelectric output. Chapter 4 presents the Energy Commission's

5 SCE provided firm DER values that appear in this report.

evaluation of DER at the transmission level, including estimates for low and high hydroelectric output.

Figure 6: Transmission Case Studies



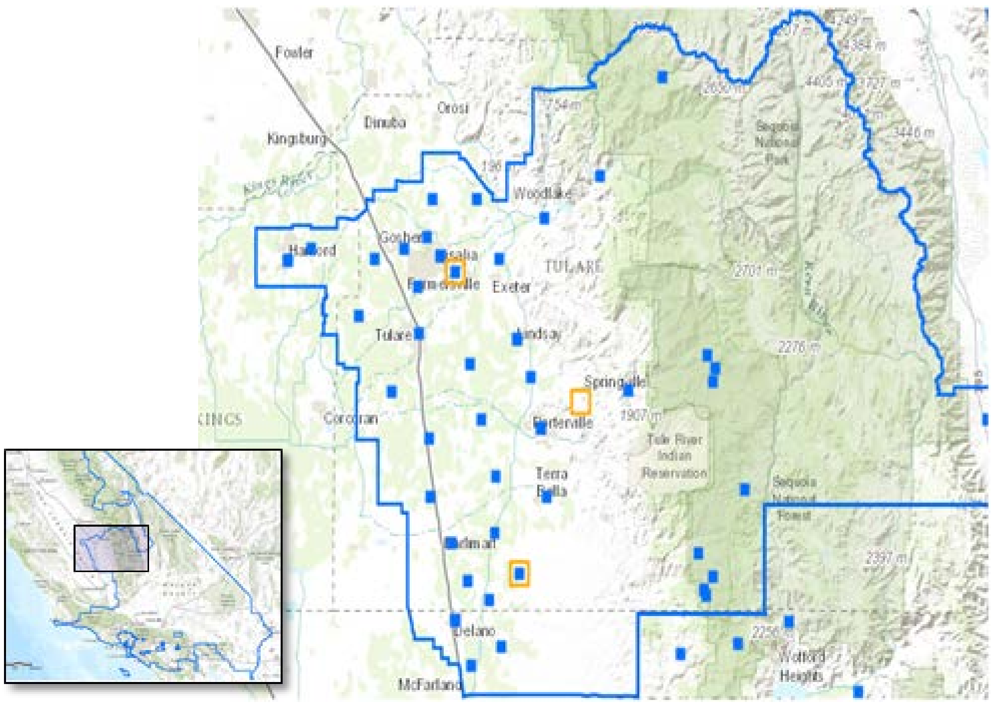
Source: Navigant

CHAPTER 2: San Joaquin Valley Region

Pilot Area Description

The SJV region is located primarily in Tulare County within California's Central Valley. It extends slightly into Kings County to the west and Kern County to the south. Tulare County has significant agricultural lands, about 1.3 million acres, and is California's largest dairy- and cattle-producing county. This region contains the northernmost load center in SCE's service territory and has significant agricultural electrical load. **Figure 7** presents the boundary of SCE's electric service territory located with the SJV region and substation locations.

Figure 7: Map of San Joaquin Valley Region



Source: Navigant created the map using Distributed Energy Resource Interconnection Map (DeRIM) tool.

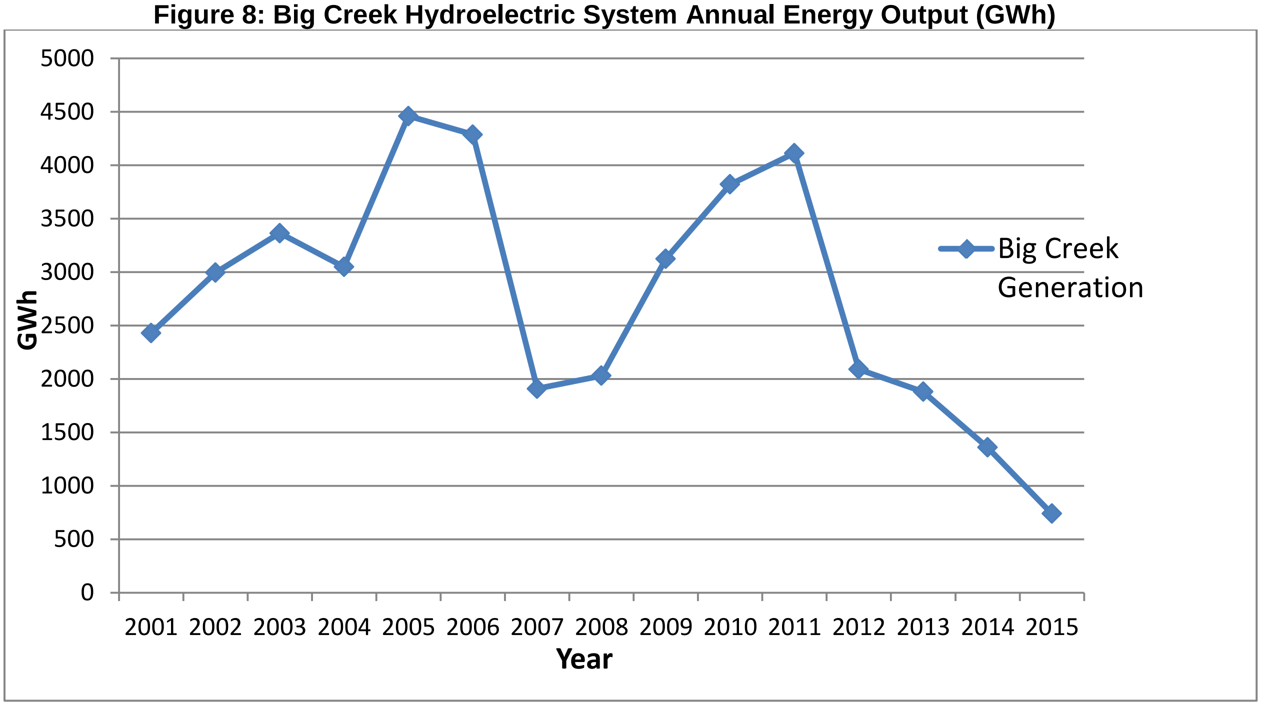
The Energy Commission and SCE selected the SJV region for the study for several reasons:

- Unique circumstances caused by ongoing drought conditions
- Increased agricultural load from groundwater pumping
- DER development potential due, in part, to land conversion from agricultural use, which has declined due to low rainfall, to more economical use, such as leasing for solar PV development

- Reduced output from in-region hydroelectric generation
- Potential for enhanced DER benefits
- Higher-than-average load growth, resulting in increased potential for distribution capacity deferral
- Potential deferral of transmission investments required to address reduced output from in-region hydroelectric generation caused by drought conditions.

The SCE Big Creek Hydroelectric System,[6] collectively rated at about 1,000 MW, is located just north of the SJV region and supports the electric system in the area. However, reduced output caused by persistent drought conditions, illustrated in **Figure 8**,[7] could compromise the degree to which hydro sources can be relied upon to provide electric system support, particularly if load continues to grow in the region. Importantly, the region would see further reductions in hydroelectric system support if drought conditions were to continue over the next decade.

Figure 8: Big Creek Hydroelectric System Annual Energy Output (GWh)



Source: Energy Commission

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6 The Big Creek Hydroelectric System consists of a series of generators within the Big Creek River watershed. Electric output from these units is coordinated via centralized scheduling systems along with other generators in the greater regional area.

7 The ongoing drought conditions in 2014 and 2015, coupled with continuance of low rainfall after 2015, can cause hydro output to drop well below historical levels.

The impact of reduced hydroelectric output on the area's transmission network and the role of DER to address these impacts are further evaluated in Chapter 4.

San Joaquin Valley Region Distribution System

The SJV region has 56 substations, including three A-Bank substations: Rector 220/66kV, Springville 220/66kV, and Vestal 220/66kV. The A-Bank substations step down transmission voltages to subtransmission voltages. Lower voltage B-Banks are fed by A-Bank substations, and sometimes there are additional levels of voltage step-downs. The number of substations, by type, is presented in **Table 6.**

Table 6: San Joaquin Region Substations

Substation Type	Description (High/Low Voltage)	Number
A-Bank	220/66 kV	3
B-Bank	66/12 kV	41
B-Bank	66/4.16 kV	5
C	12/4.16 kV	7

Source: Navigant analysis of SCE data

The key attributes of SJV region distribution feeders are summarized in **Table 7.** Feeders within the region are predominantly 12 kV, and those operating at lower voltages typically serve less load.

Table 7: San Joaquin Region Feeder Properties

Primary Voltage	Number of Feeders	Average Length (miles)	Average Customers Served	Average Noncoincident Peak (kW)
12	207	27	627	6,216
4.16	22	3	257	1,336

Source: Navigant analysis of SCE data

Generation

The SJV region has significant amounts of hydroelectric generation, and the output is dependent on weather conditions. Thus, the Energy Commission explored a low and a high hydroelectric case, each presented in **Table 8.**

Table 8: San Joaquin Valley Region Generation

Generation	Plant	Low Hydro Case (MW)	High Hydro Case (MW)
Hydro	Big Creek	43	593
	Eastwood	207	207
	Mammoth	0	178
	Small Hydro	0	130

<table>
<tr><th>Generation</th><th>Plant</th><th>Low Hydro Case (MW)</th><th>High Hydro Case (MW)</th></tr>
<tr><td colspan="2">Total Hydro</td><td>250</td><td>1,109</td></tr>
<tr><td rowspan="2">Other Generation</td><td>PV @ Vestal (new)</td><td>27</td><td>27</td></tr>
<tr><td>Customer Gen[8]</td><td>586</td><td>745</td></tr>
<tr><td colspan="2">Total Generation</td><td>863</td><td>1,881</td></tr>
</table>

Source: Navigant analysis of SCE data

Load Forecast

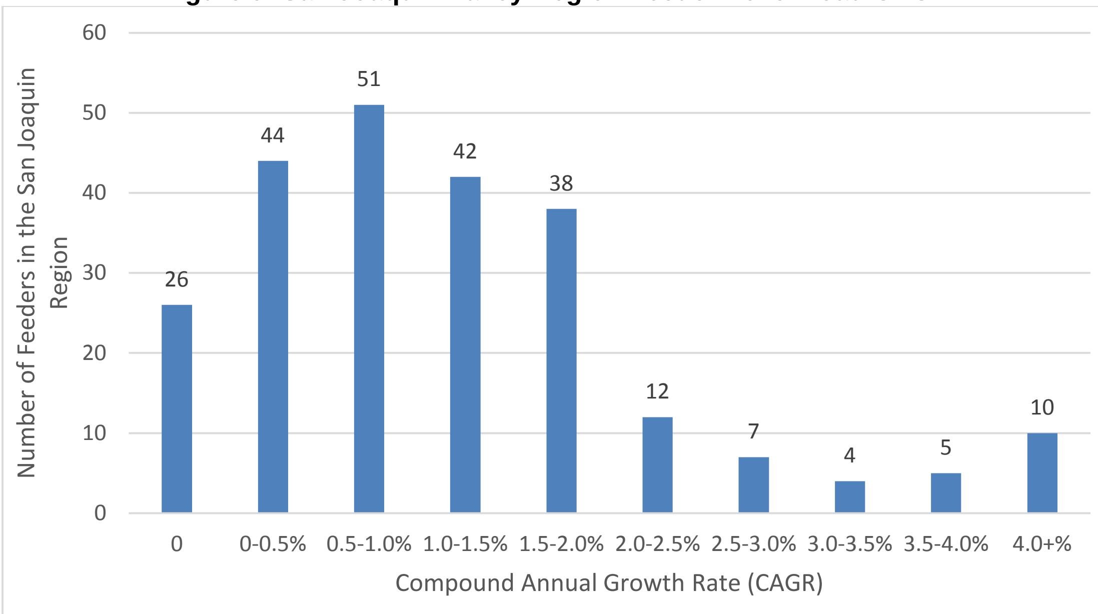
Load growth is not evenly distributed within the SJV region. For example, feeders served from the Vestal substation (located in the southern part of the study area) are expected to grow at much higher rates than other areas. However, overall growth in the region is robust, as the average 1.5 percent annual growth is higher than many other SCE regions. The higher growth rate suggests greater opportunities for transmission and distribution (T&D) capacity deferrals, such as new transmission lines and substations.

The distribution of load growth for the 239 SJV region feeders is presented in **Figure 9** where peak demand on 26 feeders is forecast to increase by a compound annual growth rate (CAGR) of 2.5 percent or greater. The high growth on many rural feeders is due to increased load for agricultural pumping.[9]

8 Some of the increased pumping load is due to absence of rainfall and nonreplenished reservoirs.

9 Low hydro case includes 586 MW interconnected at Magunden. The high hydroelectric case includes 592 MW interconnected at Magunden and 153 MW interconnected at Vestal.

Figure 9: San Joaquin Valley Region Feeder-Level Load CAGR



Source: Navigant analysis of SCE data

Customers and Load

The SJV region is located in California's Central Valley, which includes a mix of urban, suburban, agricultural, and rural load. The 2012 annual noncoincident peak for the region was 1,397 MW.[10]

Table 9 lists the number of customer by class and the sum of noncoincident distribution peaks.

Table 9: 2012 San Joaquin Valley Region Load Composition

Customer Class	Number of Customers	Aggregate Feeder Noncoincident Load (MW)
Residential	**108,684**	567
Commercial	**28,877**	282
Industrial	**952**	156
Agricultural	**31,582**	391
Total	**170,095**	**1,397**

Source: Navigant analysis of SCE data

[10] Non-coincident peak is the maximum energy demand of the region at any particular time.

DER Forecast

This study leverages SCE's DER forecasts included in its July 2015 DRP. This study uses two DER growth scenarios from the DRP: the BAU scenario and the VA scenario.

The DRP considered six DER technologies and programs, listed in **Table 10**, which were evaluated for the SJV region. The nameplate capacity is based on total DG installed, or total demand reduction of energy efficiency and demand responses programs – the actual amount of energy efficiency typically is well below maximum levels at the time of the feeder peak, particularly on residential feeders with high mid-day loads. Electric vehicles appear as a negative value because they operate in charging mode at the time of the system peak.

As noted, the location of DER throughout the SJV region is not forecasted to be uniform. It depends highly on the location of load centers for smaller DER and suitable sites for large DG, the latter of which is combined heat and power (CHP) or ground-based solar plants.

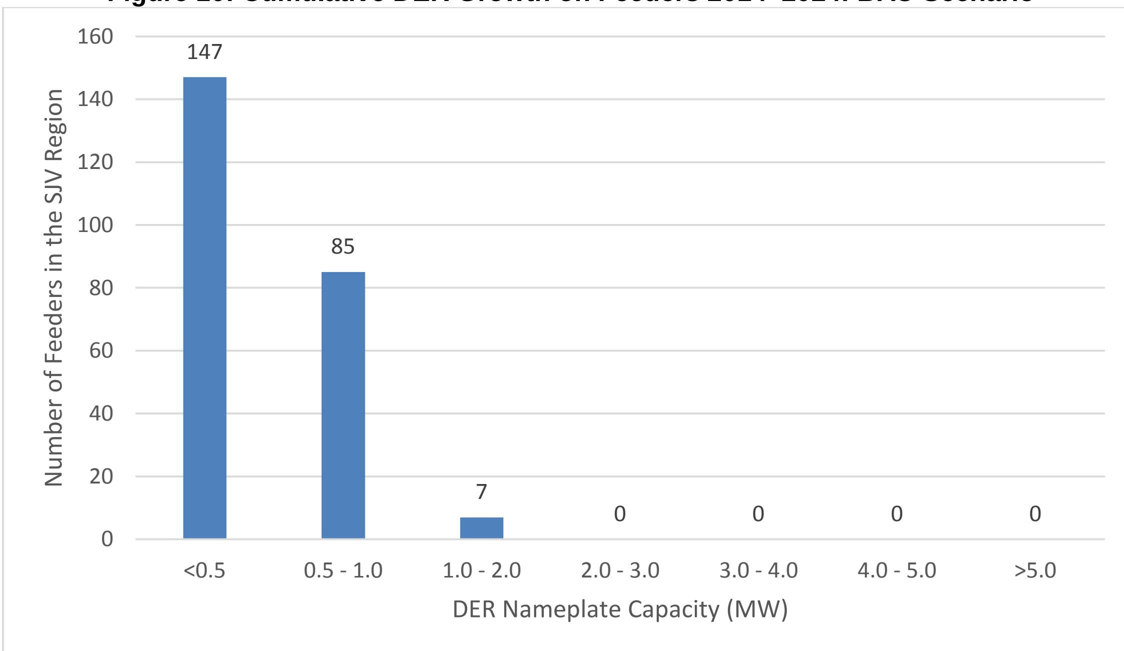
Table 10: Nameplate DER Forecast for the San Joaquin Region

	Business-as-Usual Scenario (MW)	Very Aggressive Scenario (MW)
DER	**Nameplate**	**Nameplate**
Additional Achievable Energy Efficiency (AAEE)	106.1	768.0
Photovoltaic (PV)	38.7	190.8
Combined Heat and Power (CHP)	4.6	51.6
Demand Response (DR)	2.8	156.5
Electric Vehicle (EV)	-7.0	-15.3
Energy Storage (ES)	25.4	56.3
Total	**170.6**	**1,207.9**

Source: Navigant analysis of SCE data

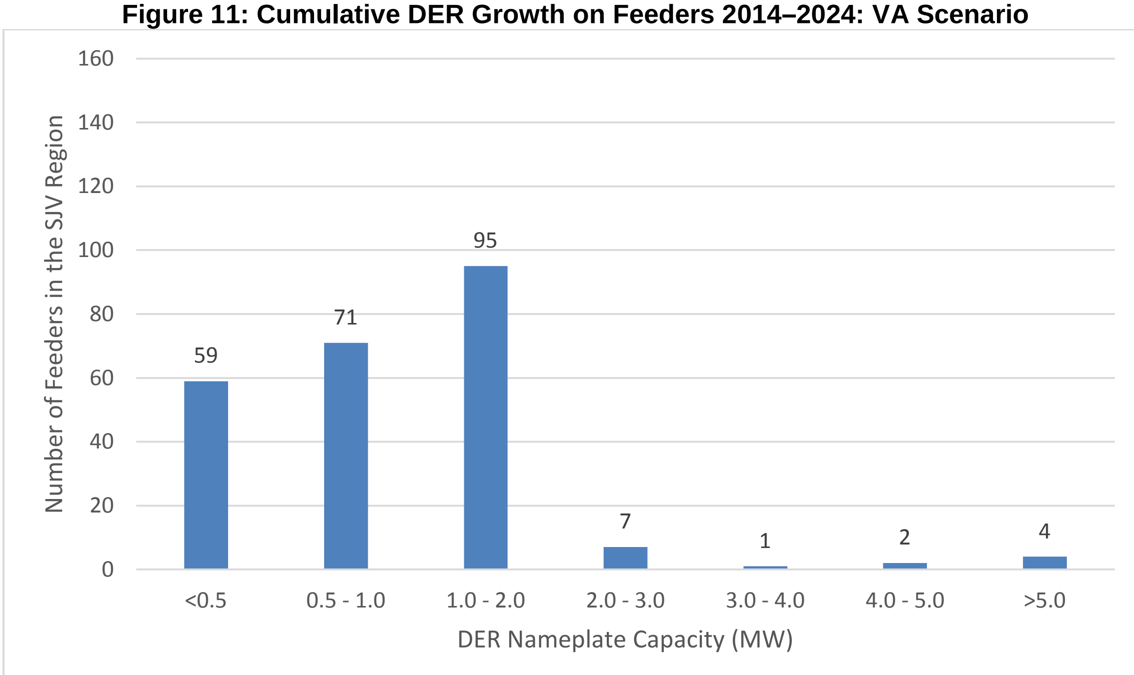
Figure 10 and **Figure 11** illustrate the DER forecasts for each scenario.

Figure 10: Cumulative DER Growth on Feeders 2014–2024: BAU Scenario



Source: Navigant analysis of SCE data

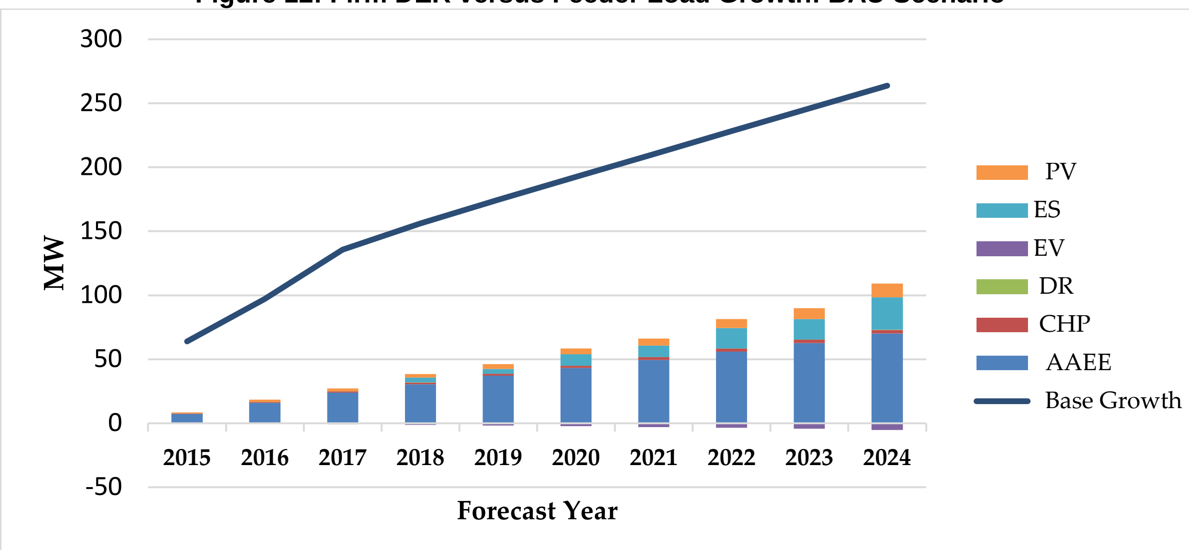
Figure 11: Cumulative DER Growth on Feeders 2014–2024: VA Scenario



Source: Navigant analysis of SCE data

The capability of firm DER to supply future load is an important potential benefit. For each DER scenario, SCE provided total installed and firm DER for each feeder in the region. **Figure 12** presents total noncoincident peak (NCP) for the 239 feeders in the SJV region versus total firm DER capacity for the BAU Scenario.[11] The chart indicates peak load growth is significantly greater than the increase in the DER coincident peak forecast for the BAU Scenario. Furthermore, the ratio of DER output to the feeder peak load for any feeder may be lower than the ratio of the total DER output to the region load at the hour of the system peak because some feeders peak at a time of the day when DER output is low. For example, some feeders peak during early evening hours when solar output is low. Other feeders with significant agricultural load peak in early morning hours when solar output is nil.

Figure 12: Firm DER versus Feeder Load Growth: BAU Scenario



Source: Navigant analysis of SCE data

Figure 13 compares firm DER capacity to NCP growth for the VA Scenario. In contrast to the BAU scenario, SJV region load growth is about equal to the DER peak forecast for the VA scenario, which suggests greater opportunities for capacity deferral for the aggressive DER cases. Capacity deferral opportunities apply to both transmission and distribution, with specific results presented in subsequent sections.

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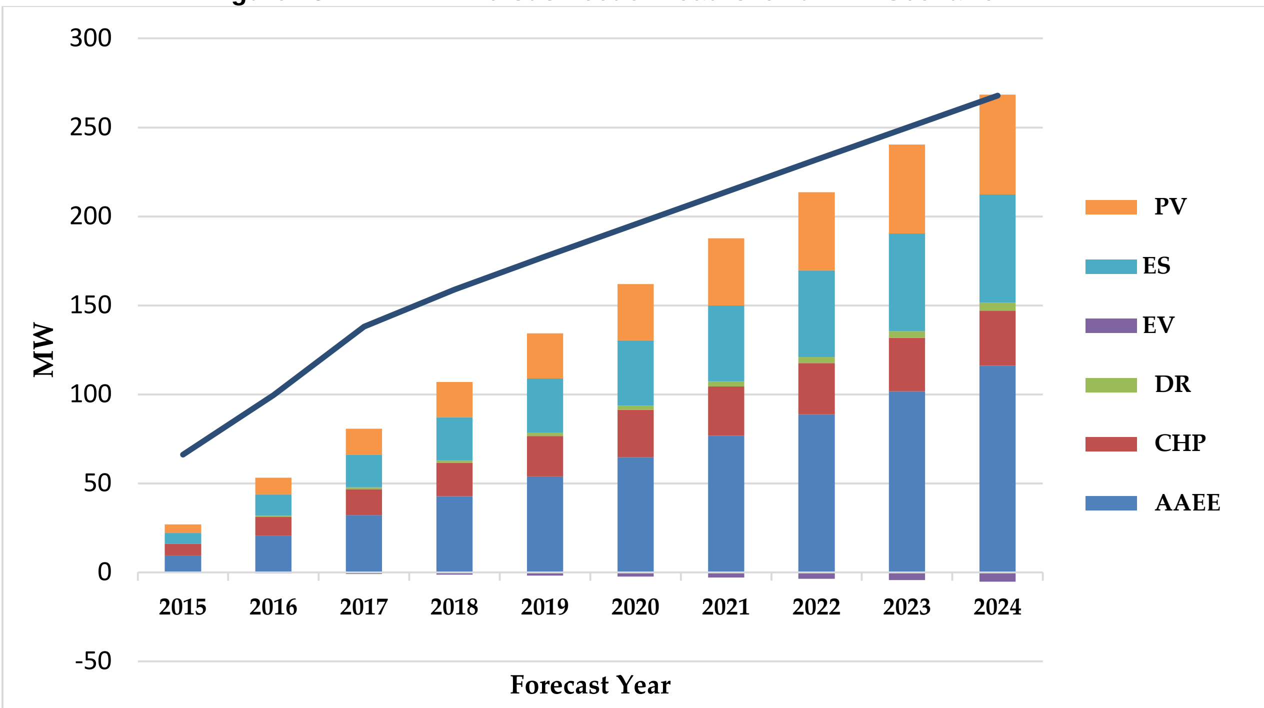
11 DER capacities are maximum firm values at the time of the system peak and may not be coincident with the feeder peaks; hence, coincident DER capacity is lower than values displayed in the chart.

Figure 13: Firm DER versus Feeder Load Growth: VA Scenario



Source: Navigant analysis of SCE data

CHAPTER 3: Distribution Analysis

This chapter presents the Energy Commission's analysis of distribution-level DER impacts, and interconnection benefits and costs for each of the case studies under the BAU and VA scenarios. It describes the methods and assumptions used to predict impacts and the models applied to simulate DER impacts on SCE's distribution system for the SJV region.

DER Costs

For this study, total installed DER cost includes three elements:

- Distribution system upgrades
- Distributed resource
- Distributed resource connection

Distribution system upgrade costs are the investments or expense-related actions that may be required to ensure the installation of DER does not violate thermal loading or voltage limits on distribution lines or substations. System upgrades also may include upgrades or changes needed to address operational impacts (such as accommodating load transfers during normal maintenance or emergencies) or to ensure protective relaying is not compromised. The *distributed resource cost* is the installed cost of the DER resource to the owner prior to interconnection, and the *connection cost* is the cost of upgrades and equipment that are needed to connect DER to distribution lines or substations.[12]

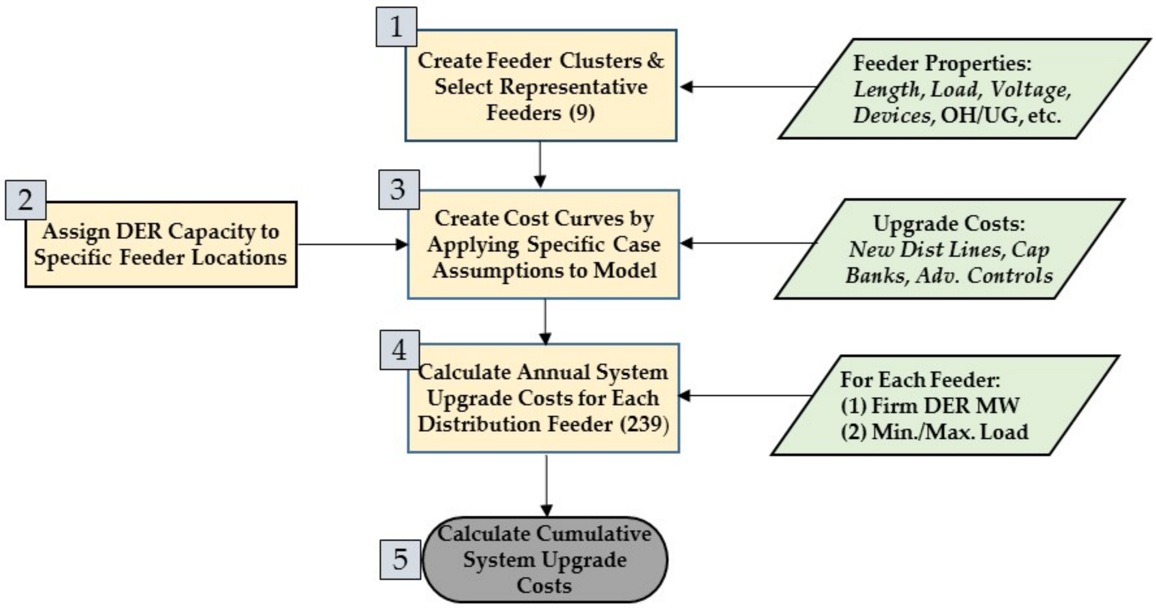
Method for Determining System Upgrade Costs

The primary focus of estimating DER impacts at the distribution level focused on attaining results that are statistically rigorous while expediting the process of modeling all feeders in the SJV region. This study followed the approach undertaken in the Phase I study, which begins by selecting a subset of feeders (that is, representative feeder clusters) that are both suitable and accurate representations of all distribution feeders in the region. Then standard selection criteria for locating DER resources along a feeder were applied to each

12 Connection costs also include protection, monitoring, and communications systems required as a condition of the interconnection requirements under Rule 21. Supervisory Control and Data Acquisition (SCADA) communications and controls are typically required for DG rated 1 MW and above and are the responsibility of the owner.

representative feeder. Next, load-flow simulations using analytical models were conducted to predict system upgrade costs for each representative feeder for increasing amounts of DER (ranging in capacity from zero to the maximum feeder rating). The cost of system upgrades then was derived for each of the six cases over a 10-year time frame. **Figure 14** and **Table 11** illustrate the steps and the approach the Energy Commission followed to predict system upgrade costs for each DER case study over the 10-year study. Distributed resource and connection costs are discussed in subsequent sections.

Figure 14: Flowchart to Determine System Upgrade Costs



Source: Navigant

Each step listed in **Figure 14** is described in detail in sections that follow.

Representative Feeder Selection Process

The distribution impact analysis requires the selection of a statistically representative feeder sample to assess the benefits and costs of various DER. Similar to the Phase I study, the Energy Commission selected a subset of representative feeders to predict DER total interconnection costs for the distribution feeders in the SJV region. The selection of a representative set of feeders avoids the inherent constraints and inefficiencies associated with attempting to simulate the impact of DER on all SCE feeders, while providing a sound basis for predicting system wide costs.

Table 11: Description of Approach to Determine Cumulative System Upgrade Costs

Step	Description
1. Create clusters & select representative feeders	Use preidentified properties to determine prototypical feeder groups in the SJV region and determine the minimum number of feeder clusters to represent all distribution feeders (about 250). Feeder selection is based on grouping feeders that have properties that are most similar to the average profile within a cluster.
2. Assign DER to Specific Feeder Locations.	A mix of behind-the-meter and non-behind-the-meter generators is modeled on the simulated feeders. The percentage of commercial/industrial load vs. residential load informed the ratio of behind-the-meter vs. non-behind-the-meter generation. All DER that is inverter interfaced is gathered to “feed-in” points located near customer load centers.
3. Create Cost Curves by Applying Specific Case Assumptions to Model	Conduct feeder load flow simulations for increasing amounts of DER capacity for each feeder for each of the six DER cases. Assumptions are developed and applied to specially account for smart inverters and energy storage, due to the limitations of the modeling software. Smart inverters are approximated by assuming that all PV/CHP units (behind-the-meter) are available for power factor based voltage control. Energy storage is approximated by running all simulations at feeder peak load instead of noontime load. All simulation analysis and cases typically are run at noontime feeder loads.[13] Employ mitigation options most commonly used by SCE to accommodate DER connection to ensure that normal operating voltage and loading criteria are met. Create parametric cost curves by estimating the cost of interconnecting DER at increasing levels of capacity on each representative feeder.
4. Calculate Annual System Upgrade Costs for Each Distribution Feeder	Apply the parametric cost curves developed in Step 3 to predict DER system upgrades for the entire set of distribution feeders (239) for each case for each year of the study. The parametric cost curves are used to predict system upgrade costs as a function of the amount of DER capacity added over the 10-year horizon.
5. Calculate Cumulative System Upgrade Costs	Sum annual upgrade costs for each of the representative feeders for each of the six DER cases. Results include total system upgrade cost for each of the six cases for years 1 through 10.

Source: Navigant.

13 Solar PV is the only weather-dependent resource modeled; therefore, simulating the noontime conditions reflects the maximum impact that DER would have on feeder operation.

Standard k-means clustering of 239 feeders was performed to develop an operationally representative subset of feeders for SCE's SJV region.[14] The process is designed to identify a subset of feeders that have common attributes such that any feeder within a cluster is similar to all other feeders within the cluster. Typically, the feeder that is deemed the "most average" within the cluster is selected as the representative feeder. Because of the wide range of attributes, some clusters are typically populated with a larger number of feeders than others. For example, clusters with shorter urban feeders often contain many feeders, whereas clusters with longer rural feeders often have a smaller number of feeders.

Navigant clustered the feeders within the SJV region based on the properties listed in **Table 12**. These properties were selected to diversify feeder clusters to best represent SCE's distribution system in the region. The weighting of feeder properties also reflects the significance each property is likely to have with respect to DER impacts on feeder performance. For example, the amount of solar that can be installed on a feeder depends highly on feeder voltage—typically, the higher the feeder voltage, the greater amount of DER capacity that can be installed before limits are reached and mitigation is required before any additional DER can be added.

Table 12: Feeder Property and Weighting Factor

Feeder Property	Weighting Factor
Voltage	3
Mileage	3
Load	3
Number of Capacitors	2
% of Phase Line by Mileage	2
Customer Count	1

Source: Navigant

The clustering algorithm and approach to feeder selection for this study are commonly used to select representative feeders for a distribution system.[15] The profile of the

14 This value is lower than the entire set feeders in SJV region (about 250). Several dedicated feeders and those with minimal length or other factors that were assessed as unlikely/unable to connect solar generation were eliminated from the total set of 250.

15 The feeder selection method applied in Navigant's analysis is based on a statistical approach developed in the early 1980s and subsequently applied by utilities and industry analysts. Further reference on the foundation and method to this approach is described in the research paper, "A Cluster-Based Method of Building Representative Models of Distribution Systems," H. L. Willis, H. N. Tram, and R. W. Powell, *IEEE Transactions on Power Apparatus and Systems*, March 1983, p. 1776.

representative feeder selected for each cluster is the one that best represents a larger set of feeders with common attributes within the entire cluster.

A key precept, or rule, of using the clustering algorithm is that the number of clusters required to be produced must be specified before execution. Therefore, the results of the clustering are heuristic; the clusters must be evaluated for suitability after the algorithm executes, and trial and error is required to find the number of clusters required for a suitable representation of the system.

The k-means clustering algorithm used by Navigant was initialized using a process known as “k-means++” in data mining. The process begins by uniformly selecting a single feeder within the entire population at random to act as the center of the first cluster. Then, a second feeder is selected randomly, with greater weighting assigned to feeders that have properties most different from the first. This process continues until a number of candidates selected to be centers equals the number of clusters specified. The remaining feeders are compared to these cluster centers by calculating the Euclidean, or straight-line, distance between them, for each property in **Table 12**. The feeders are sorted into groups with other similar feeders, each of which is similar to the cluster center. Then, the average profile for each of these clusters is calculated, and the centers for each cluster are updated. The algorithm iterates this process of defining centers and then clusters the remaining feeders around the centers until the clusters meet a threshold condition for internal distance.

Typically, five to six representative feeders would be sufficient for a distribution system comparable in size and configuration as feeders within the SJV region. However, the Energy Commission sought to apply a greater level of rigor to the study and, therefore, increased the set of representative feeders to nine. Supporting the use of a larger sample is the broader range of DER technologies and programs. In Phase I, most DER was in the form of solar DG, whereas in Phase II, additional DER is considered.

Table 13 presents the average profile of the average feeder for each of the nine clusters selected for San Joaquin using the k-means clustering approach described above. It lists the average value for each of the key properties used in the clustering algorithm. Notably, other than one representative feeder at 4.16 kV, the greatest variance between each cluster is total length and total number of customers, suggesting that clusters are largely defined by urban versus rural location—longer feeders typically are in rural areas.

Table 13: Average Properties of the Feeder Clusters in the San Joaquin Region

Cluster	Voltage (kV)	Length (mile)	Peak Load (MW)	Number of Capacitors	3 Phase (%)	Total Customers
1	12	64.7	7.0	11	84%	903
2	12	15.1	3.0	3	92%	229
3	12	35.8	8.3	6	78%	1,110
4	4.16	7.0	2.8	3	84%	270
5	12	13.5	7.3	4	81%	594
6	12	29.9	3.8	4	95%	259
7	12	17.3	8.5	5	54%	1,138
8	12	37.2	6.7	7	97%	246
9	12	47.0	4.9	5	87%	478

Source: Navigant analysis of SCE data

Table 14 presents the total mileage, customers, and load for each of the nine clusters. It also shows the percentage of feeders in the region that each cluster represents and indicates that, relatively, Cluster 7 contains the most feeders and Cluster 1 the fewest.

Table 15 lists each of the representative feeders the Energy Commission, in consultation with SCE, selected for each cluster. (As described above, a single feeder from each group is selected for load flow modeling to reduce analysis time while remaining statistically accurate.) These representative feeders have similar properties to the average profile for each cluster presented in **Table 13.** The representative feeders are dispersed throughout the SJV region.

Table 14: Total Properties Represented by the Clusters

Cluster	Number of Feeders	% of San Joaquin Valley Region by Number of Feeders	Total Mileage	Total Customers	Total Load (MW)
1	11	4.6%	712	9,933	77
2	33	13.8%	497	7,559	99
3	20	8.4%	715	22,191	167
4	22	9.2%	154	5,948	62
5	34	14.2%	460	20,189	248
6	35	14.6%	1,046	9,049	135
7	46	19.2%	795	52,336	390
8	23	9.6%	856	5,655	155
9	15	6.3%	704	7,166	74
Total	**239**	**100.0%**	**5,941**	**140,026**	**1,406**

Source: Navigant analysis of SCE data

Table 15: Representative Feeder Selection for the San Joaquin Valley Region

Cluster	Voltage (kV)	Length (mi)	Peak Load (MW)	Number of Capacitors	3 Phase (%)	Total Customers
1	12	61.6	7.3	8	55%	1086
2	12	10.0	2.8	4	89%	392
3	12	34.6	11.3	7	79%	1409
4	4.16	4.1	2.4	1	84%	230
5	12	12.2	4.9	5	90%	805
6	12	32.1	4.5	4	84%	910
7	12	11.0	9.5	3	67%	1240
8	12	43.7	7.1	5	92%	671
9	12	48.4	5.1	6	86%	607

Source: Navigant analysis of SCE data

Modeling Assumptions

In contrast to the Phase I study, where most DER was solar, Phase II includes a range of DER technologies and programs. Accordingly, it was necessary to account for differences in DER capacities, operating characteristics, and output profiles when setting up the feeder model. **Table 16** describes the modeling assumptions used for each DER technology.

Table 16: DER Modeling Assumptions

DER Type	Modifies Load	Modifies Generation	Description
AAEE	Yes	No	Reduces load on the representative feeders
PV	No	Yes	Connected inverter based generation
DR	Yes	No	Reduces load on the modeled feeders
ES	Yes	Yes	All connected inverters considered inverter interfaced storage devices matched to PV size and discharged at the time of the feeder peak.
CHP	No	Yes	Connected inverter based generation

Source: Navigant

The next step in the evaluation is the creation of simulation model databases for each of the nine representative feeders. The CYME[16] Distribution Load Flow model was used to conduct the simulation analysis. The CYME model is the same tool that SCE uses to conduct distribution feeder analyses and was used by SCE to support the determination of hosting capacity in its draft DRP and reported in its Web-based Distributed Energy Resource Interconnection Map (DeRIM).

Figure 15 highlights the location of DER (that is, solar PV and CHP generators) feed-in points for one of the nine representative feeders. Each of the feed-in points is a feeder location where one or more DER technologies are installed. Each feed-in point can represent a single large DG unit or the combination of several small DG units such as net-metered solar. Each feed-in point also includes load reduction achieved by energy efficiency or demand response. The amount of DER at each feed-in point varies based on the number of customers or load served on line segments, as the number of DG units or amount of EE is a function of the number of customers located on each segment. All DER is aggregated at a single feed-in point on a feeder segment to avoid the need to model each DER unit, which could be a several hundred devices for high-penetration DER. In this example and the eight other representative feeders, a sufficient number of feed-in points for modeled generators were selected to ensure accurate results from the simulation model.

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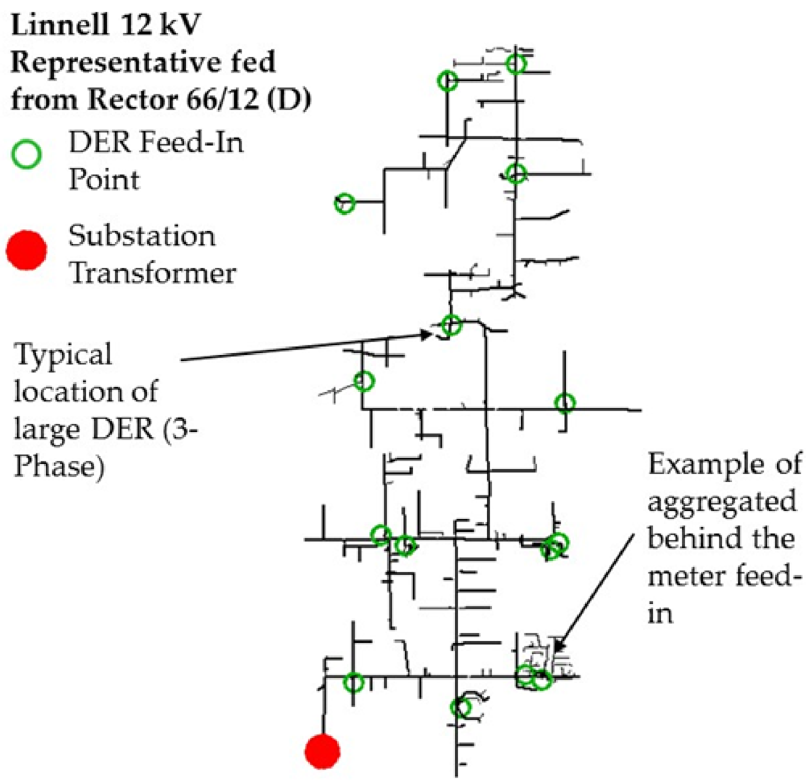
16 The CYME Power Engineering Software and Solutions suite of tools is a commercial model offered by Cooper Power Systems via its Eaton Power Systems division.

Figure 15: Typical Feeder Model



Source: Navigant illustration based on CYME feeder model. DER that is modeled includes PV, CHP, and energy storage

In this example for the Linnell 12 kV feeder, the following lists key assumptions applied to the DER load flow model.

- A minimum of 15 generator feed-in points is required to accurately model DER.
- Ten feed-in points are combined behind the meter; five are non-behind-the-meter feed-in points.
- Feed-in points for non-behind-the-meter DER are located near large commercial/ industrial loads.
- Aggregate feed-in points for behind-the-meter DER are at or near residential areas, mostly on lateral feeder line segments.

A similar approach is applied to the other eight representative feeders.

Following feeder model setup, load flow simulation studies were conducted for each of the six cases presented in **Table 2** using inverter deployment and, where applicable, energy storage strategies outlined in **Table 17**.

Table 17: Case Study Assumptions

"Regular inverter deployment"	
Modeled load assumption	• Simulations assessed at feeder load that coincides with the maximum point in composite DER output curve; that is, when the coincident output for composite DER output is highest. • This loading condition results in the greatest steady state impacts in voltage and loading due to DER.
Modeled DER assumption	• Power factor adjustment is available only for non-behind-the-meter generators (greater than 1 MW only, located at commercial and industrial load sites). Less inverter-based DER can be used to reduce overvoltage, and costlier mitigation options must be selected.
"Smart inverter deployment"	
Modeled load assumption	• Simulations assessed at feeder load that coincide with the maximum point in composite DER output curve; that is, when the coincident output of DER is highest. • This loading condition results in the greatest steady-state impacts in voltage and loading due to DER.
Modeled DER assumption	• Power factor adjustment is available for all inverter-based DER (behind-the-meter and non-behind-the-meter units). More DG can be used to reduce overvoltage, and, therefore, more costly mitigation options are avoided.
"Storage assumptions with smart inverter deployment"	
Modeled load assumption	• Load flow simulation and impacts are assessed at peak feeder load (as opposed to time of maximum solar output). • This assumption approximates scheduling energy storage units to shift DER effects to coincide with the feeder peak. • Operating energy storage in this manner produces fewer steady-state voltage and loading violations due to oversupply from DER
Modeled DER assumption	• Power factor adjustment is available for all inverter-based DER (behind-the-meter and non-behind-the-meter units). More inverter-based DER can be used to reduce overvoltage, and, therefore, more costly mitigation options are avoided.[17]

Source: Navigant.

Because several of the DER technologies either operate intermittently or do not produce rated output at the time of the feeder peak, each were derated based on the respective output profiles (also, see **Figure 20**). **Table 18** presents DER nameplate capacity as of 2024, and output coincident with the noontime solar peak versus the feeder peak. The latter two

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17 This assumption is in accordance with the Energy Commission/CPUC Rule 21 draft document "Recommendations for Requirements for SIWG Phase 3 Functions,", Section 16.1 "Watt-Power-Factor Function"

values are well below nameplate rating, as the large amount of energy efficiency, more than 50 percent of total capacity, converts to much smaller net output, particularly for residential programs where net coincident demand reduction typically is about 20 percent of total gross program participation. Similarly, feeder peaks in the SJV region often occur late afternoon or early evening, further reducing coincident DER output.

Table 18: DER Capacity and Net Output

Case	Description	2024 DER Nameplate Capacity (MW)	2024 DER Noontime Output (MW)	2024 DER Coincident With Feeder Peak (MW)
1	BAU Forecast, Standard Inverters	171	134	104
2	VA Forecast, Standard Inverters	1208	375	259
3	VA Forecast, Advanced Inverters	1208	375	259
4	VA Forecast, Advanced Inverters and Energy Storage	1208	315[18]	319
5	VA Forecast, Advanced Inverters With DER Targeted to Minimize Cost	1208	375	259
6	VA Forecast, Advanced Inverters With DER Targeted to Maximize Benefits	1208	375	259

Source: Navigant analysis of SCE data

Mitigation Options and Cost

The Energy Commission considered several options to reduce solar capacity impacts on the primary distribution system,[19] including new or upgraded feeders and controls; new equipment is installed when existing lines and substations are incapable of interconnecting solar. Notably, enabling inverter control and strategically deploying storage technology to reduce overvoltage is significantly less costly than other mitigation options.

18 Assumed that forecasted storage would be able to reduce PV output at noontime and shift in bulk to feeder peak.

19 Secondary impacts were not directly evaluated as the simulation model database includes only lines operating at primary voltages. Further, the cost of secondary upgrades typically is included in the cost of connection charged to the DER owner.

Table 19 lists solutions evaluated to reduce impacts and derive integration costs at the distribution level. These options are typically those applied by utilities to address steady-state impacts and are consistent with planning criteria and solutions used by SCE. Most are traditional capacity upgrades, usually through replacement of existing equipment with higher-rated devices or lines.

Table 19: Mitigation Cost

Description	Cost ($000)
Inverter Power Factor Adjustment	$0[20]
Capacitor Bank Setting Adjustment	$5
Replace Line Fuse	$14
New Capacitor Bank	$54
Load Tap Changer Controls	$80
New Recloser	$82
Statcom	$200
New Regulator	$203
Reconductor Overhead - 1 Phase (per mile)	$481
Reconductor Overhead - 3 Phase Rural (per mile)	$581
New 3 Phase Underground Cable	$1,584
New Distribution Feeder	$2,500
New Substation XFMR Bank	$5,000

Source: Navigant analysis of SCE data

Although listed, the feeder analysis indicated that not all of the options listed above were needed or applied to address DER impacts. Several mitigation options and the order in which they are deployed to address DER impacts were reviewed with SCE, with preferred actions listed below:

- Power factor regulation of connecting inverter-based DER was a preferred option, as it required no physical alteration of the existing system.
- Installation of shunt capacitors and increasing feeder conductor size were also preferred options as they overlap with system upgrade efforts.

20 The cost for this mitigation measure is assumed to be 0 as SCE schedules the power factor of its larger DG customers on a case-by-case basis. It is assumed that behind-the-meter units will require enabling technology to schedule power factor adjustments and are, therefore, not available to contribute to this mitigation option. In the case that assesses advanced inverter deployment, an additional system level cost reflecting enabling technology (such as distribution management systems) should be considered for the cost curves presented in the report.

System Upgrade Cost Curves

The next step included developing formulas (cost equations) for each representative feeder to predict integration cost as a function of capacity, developed by conducting CYME load-flow simulations for inverter-based DER capacity levels ranging from 20 percent to 100 percent of the maximum feeder rating. The point at which voltage, loading, or operational violations occur defines the lower boundary of the cost curve (that is, all capacity below this threshold produces zero integration cost). The cost curves are derived based on the cost of mitigating each violation, the cost of which usually increases as a function of the amount of modeled DER.

System upgrades required for each feeder cluster can be visualized on the same axis to compare costs as a function of inverter-based DER capacity.

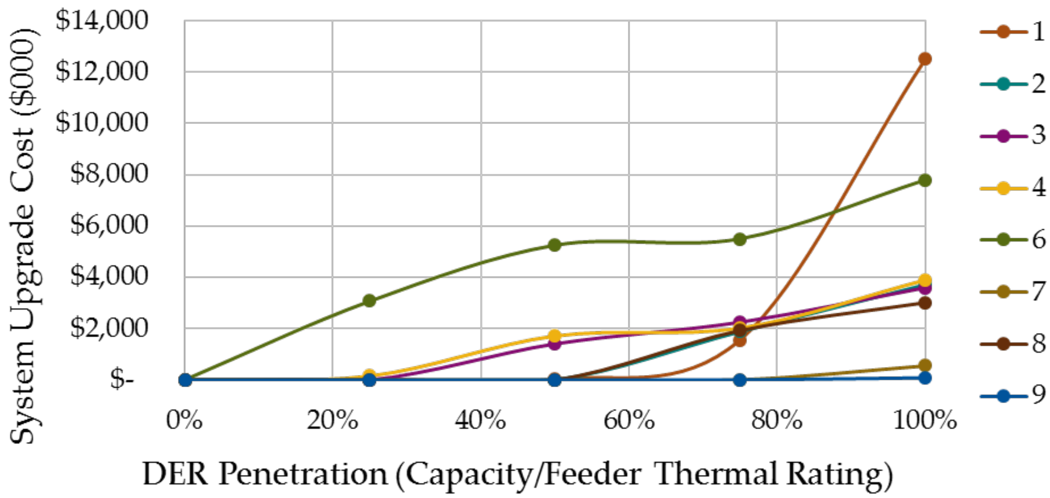
Figure 16 presents cost curves for each representative feeder based on standard inverter deployment for all inverter-based DER rated 1 MW and below. The chart lists a wide range of hosting capacities and integration costs that vary based on feeder attributes and loads, among other factors.

Key findings include:

- Cluster 5 experienced no system upgrades. It is composed of shorter, highly loaded feeders, mostly high-gauge conductors with few laterals.
- Cluster 6 experienced high predicted costs due to impacts observed at low penetration levels. It is composed of longer, lightly loaded feeders and has longer sections of lower gauge conductors.
- Cluster 1 experienced a marked increase in costs from 75 percent to 100 percent DER penetration. The cluster is composed of longer feeders with long single-phase laterals. Costs rise rapidly on these longer single-phase segments as the impact of overloads increase commensurate with cumulative amounts of DER capacity additions.

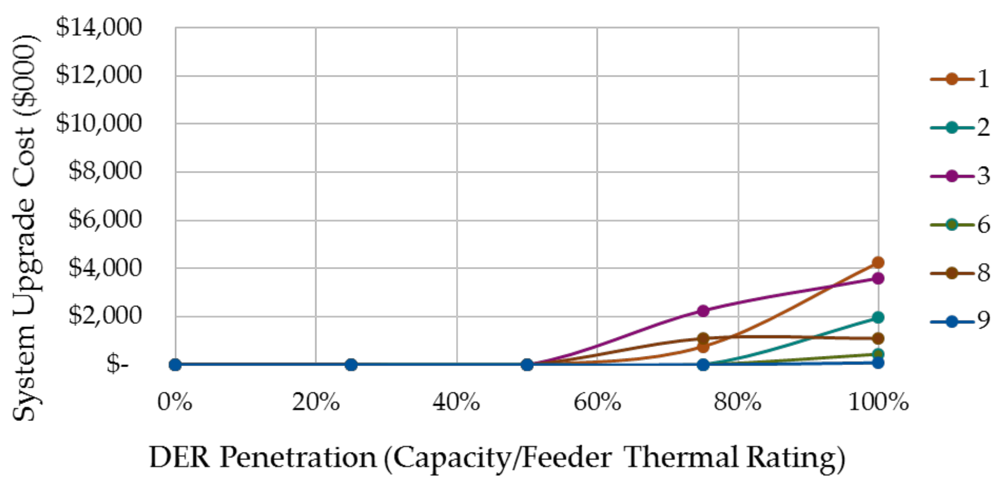
Because many of the violations are voltage-related, the ability to adjust inverter power factor on all inverters, including residential and small commercial units, via advanced communications and controls suggests integration costs could be reduced at less cost than conventional feeder upgrades. This premise was confirmed by conducting feeder load flow studies with enhanced inverter control, as it significantly reduced system upgrade costs for several representative feeders. **Figure 17** highlights the downward shift in cost for virtually all feeders. Notably, many feeders do not require system upgrades even at 100 percent DER penetration - Clusters 4, 5, and 7 did not require any system upgrades.

Figure 16: System Upgrade Cost Curves for Standard Inverter Deployment



Source: Navigant

Figure 17: System Upgrade Cost Curves for Advanced Inverter Deployment



Source: Navigant

Interconnection Cost

System upgrades derived from cost curves were combined with connection costs to derive total interconnection costs for each of the six DER cases summarized in Error! Reference source not found.. Each of the 239 feeders in the SJV region is assigned to one of the nine feeder clusters. Cost equations for each cluster were applied to each feeder within the cluster to determine the cost of system upgrades, which varies based on feeder load and amount of DER on each of the 239 feeders.

Table 20: DER Cases

Case	Description	Inverter-Type	DER Scenario	2024 DER Capacity Coincident with Feeder Peak (MW)
1	BAU Forecast, Standard Inverters	Standard	Business as Usual	104
2	VA Forecast, Standard Inverters	Standard	Very Aggressive	259
3	VA Forecast, Advanced Inverters	Advanced	Very Aggressive	259
4	VA Forecast, Advanced Inverters and Energy Storage	Advanced	Very Aggressive	319
5	VA Forecast, Advanced Inverters With DER Targeted to Minimize Cost	Advanced	Very Aggressive	259
6	VA Forecast, Advanced Inverters With DER Targeted to Maximize Benefits	Advanced	Very Aggressive	259

Source: Navigant analysis of SCE data

Figure 18 presents cumulative system upgrade costs for the cases presented above. The relatively low cost for the BAU forecast case is due to the modest amount of DER capacity (104 MW firm by 2024) versus area load (more than 1,300 MW), which results in few system upgrades.

The number of feeders with DER capacity that exceeds hosting capacity for the BAU scenario is limited to a few feeders. This observation is supported by the following results and findings:

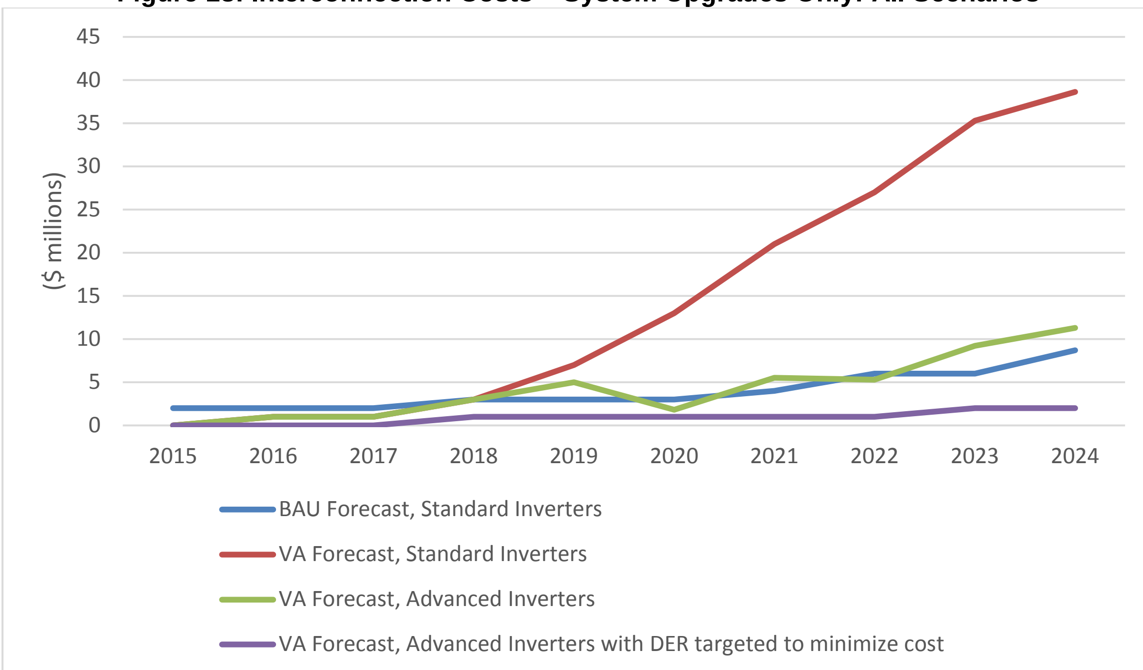
- Only 8 of 249 feeders require upgrades by 2024.
- For the eight feeders with upgrades, four have larger DER at single locations (>2 MW).
- System upgrade costs range from a low of $2 million in 2015 to a high of $9 million in 2024.

The cost of system upgrades increases significantly for higher amounts of DER capacity. The following summarizes the results of the aggressive forecast, standard inverters case:

- System upgrade costs are low until 2018 but increase significantly thereafter for the standard inverter scenario.
- Most system upgrades occur on feeders in Cluster 6. (These are longer 12.4 kV lines, located mostly in rural areas.)

- Forty-eight out of 239 (about 20 percent) of SJV feeders are expected to incur system upgrade costs by 2024.
- Total interconnection costs (connection and system upgrades) range from a low of $2 million in 2015 to a high of $39 million in 2024.

Figure 18: Interconnection Costs – System Upgrades Only: All Scenarios



Source: Navigant

Figure 18 confirms that system upgrade costs can be reduced if advanced controls are applied to inverter-based DER. Total costs for the aggressive DER forecast are reduced by almost 50 percent when advanced inverter controls are applied to inverter-based DER. The cost of system upgrades is low, as only four feeders incur system upgrade costs; the remaining amounts are DER connection costs.

System upgrade costs are further reduced when the location of DER is optimized to reduce impacts to the distribution system, which entails targeting DER to feeders that have been identified as having a relatively low cost to integrate; the cost of system upgrades is reduced to just $2 million to $3 million.

DER Resource Costs

In addition to system upgrades, the installed cost of DER resources was included in the Phase II study. Estimates of DER installed (ownership) costs provided by the Energy Commission's consultant are listed in **Table 21**.

Table 21: DER Installed Costs

DER	Installed Costs $ per kW-AC (2024)	Assumption
AAEE	100	Estimate of utility program costs.
PV	2,650	Based on weighted average of Navigant 2015 forecast for residential and commercial system with a derate factor of 85 percent.
CHP	3,400	Larger, three-phase synchronous generation (typically greater than 1 MW).
DR	250	Estimate of utility program costs.
EV	710	Level 2 charging station costs reported for an average system size of 7.5 kW from Navigant report *Communications Technologies for EV Charging Networks.*
ES	1,940	Lithium-ion technology. The cost provided are those associated with a 4-hour peak shifting application.[21]

Source: Navigant

Assumptions used for the various technologies included in the study were sourced from consultant research publications and internal assumptions. **Table 22** lists solar PV cost component by percentage provided by the Energy Commission's consultant. Notably, modules and inverters made up one-third of the estimated costs forecasted for 2024. To develop the solar PV forecast, a multistage process in which current data from interviews and reports were used to inform internal models. Moreover, professional judgment was applied to confirm and reconcile the results from the two sources. The internal starting data used for the forecast are developed through various avenues, including internal cost models derived from public company disclosures, public databases, and interviews with market leaders, including equipment manufacturers and installers. Key industry contacts are interviewed on a continuous basis; their feedback is incorporated. Also, the forecast is benchmarked against external sources, such as third-party market reports, public filings, and financial analyst estimates.[22] [23] [24] [25] [26] [27] [28] The breakdown of these costs by system component is presented in **Table 22**.

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21 From Navigant Research report, , published 3Q 2014 (Dehamna, Jaffe).

22 *Financing, Overhead, and Profit: An In-Depth Discussion of Costs Associated with Third-Party Financing of Residential and Commercial Photovoltaic Systems*, National Renewable Energy Laboratory, October 2013.

23 *Tracking the Sun VIII: An Historical Summary of the Installed Price of Photovoltaics in the United States*, Lawrence Berkeley National Laboratory, August 2015.

Table 22: Breakdown of PV Installed Costs by Component

Cost Component	% of Total Residential System Cost	% of Total Commercial System Cost
PV Modules	17%	26%
Inverter	10%	9%
Electrical Balance of System	6%	9%
Structural Balance of System	5%	6%
Direct Labor	12%	12%
Engineering	10%	6%
Supply Chain, Overhead, Margin	39%	32%
Total	**100%**	**100%**

Source: Navigant

In addition, energy storage costs were provided for lithium-ion technologies used in a 4-hour bulk storage capacity. These costs include the battery itself as well as power conversion, controls, and integration services. Finally, for related EV costs, the values are based on the cost to purchase Level 2 charging stations (servicing between 1.9 kW and 19 kW at 240 V direct current [DC]). The remainder of the installed costs provided (AAEE, DR) are estimates based on interactions with SCE and its knowledge of programs offered by the utility. In addition to the cost of each DER, an average connection cost of $149/kW was applied to each resource based on values applied in the Phase I study. This value was applied to all DER except EV, EE, and DR.

Distribution Benefits

This section presents the DER benefits analysis for each of the six cases structured under the BAU and VA scenarios (**Table 2**). It outlines the approach and assumptions used to estimate net benefits for each case. Distribution benefits include distribution substation and feeder capacity deferral up to 2024.

24 *U.S. Residential Photovoltaic (PV) System Prices, Q4 2013 Benchmarks: Cash Purchase, Fair Market Value, and Prepaid Lease Transaction Prices*, National Renewable Energy Laboratory, October 2014.

25 Solar City, Quarter 3 2015 Earnings Conference Call and Investor Presentation.

26 Deutsche Bank, May 2015.

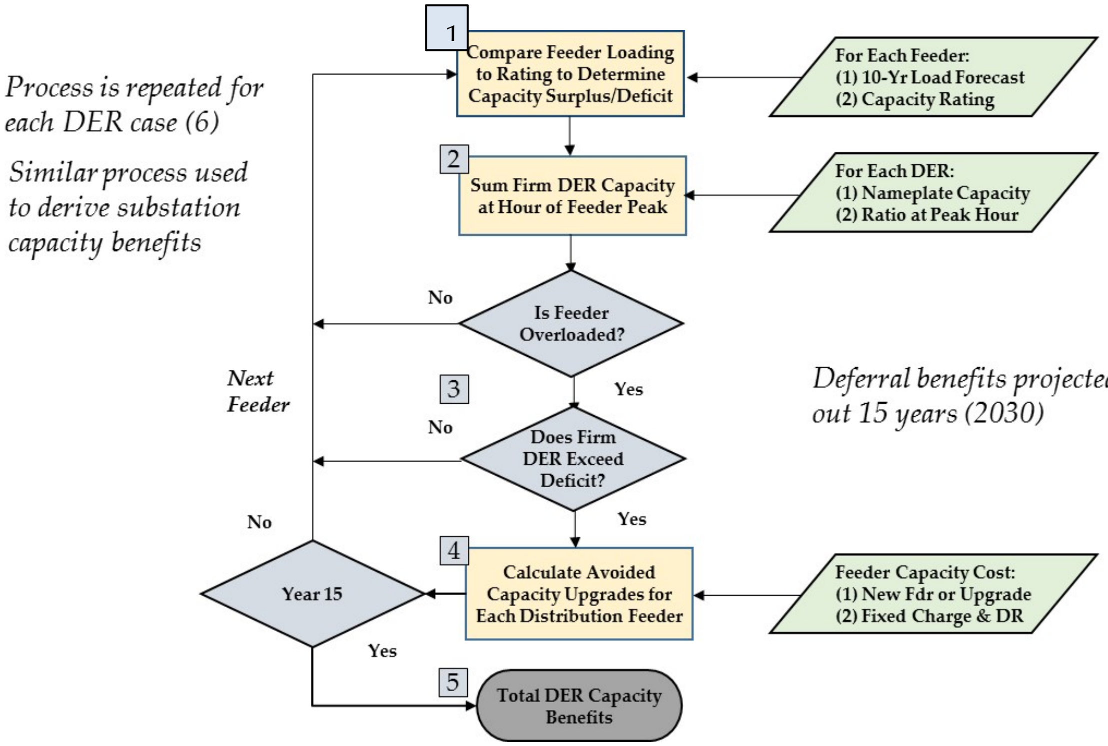
27 Lazard, September 2014.

28 *U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential, Commercial, and Utility-Scale Systems*, National Renewable Energy Laboratory, September 2015.

Summary of Approach

Figure 19 illustrates and **Table 23** describes Navigant's approach to derive distribution benefits, which focus on capacity deferral.[29] The distributed resource and connection costs are discussed in the prior section.

Figure 19: Flowchart of Approach to Determine Distribution Benefits



Source: Navigant

29 Distribution losses are excluded from the benefits analysis as load flow model results indicate losses that vary as a function of DER location and penetration. Losses tend to increase at high penetration, effectively offsetting modest reductions achieved at lower DER penetration.

Table 23: Description of Approach to Derive Distribution Benefits

Step	Description
1. Compare Feeder Loading to Rating to Determine Capacity Surplus/Deficit	Compare peak load to thermal ratings for each feeder and substation in the SJV region for each year of the 10-year planning horizon to determine annual capacity surpluses of deficits[30].
2. Sum Firm DER Capacity at Hour of Feeder Peak	Compare DER profiles to feeder load profile to determine DER output at time of feeder peaks. Adjust annual firm DER capacity assigned to each feeder by the ratio of DER output at the time of the feeder peak to the maximum firm DER rating to determine annual net firm DER capacity.
3. Does DER Firm Capacity Exceed the Feeder Capacity Deficit?	When forecasted load exceeds the feeder or substation thermal rating in any year, and if dependable DER capability "reduces" load below the feeder thermal rating plus an assigned margin[31], a feeder or substation capacity upgrade is considered "deferred" for that year.
4. Calculate Avoided Capacity Upgrades for Each Distribution Feeder	Determine number of years of feeder and capacity deferral(s). Calculate net present value (NPV) of annual deferred capacity. Assumptions include feeder avoided cost of $1 million; substation avoided cost is $5 million. A carrying charge rate of 18 percent and discount rate of 10 percent are applied to determine NPV of DER-related deferrals. The maximum number of years an upgrade can be deferred is 15. (Many feeders have fewer years of capacity deferral.)[32]
5. Total Annual Capacity Deferral Benefits	Summarize NPV of capacity deferrals for each of the 6 cases.
6. Total Annual DER Capacity Benefits	Each upgrade deferral is treated as an annuity in the years it took place, and the net present value of the total deferrals is calculated using the above assumptions.

Source: Navigant

30 The method and ratings are similar to the value and approach used by SCE in its distribution planning to identify the timing of conventional capacity upgrades and transfers.

31 For this study, a feeder or substation capacity addition was deferred when firm DER reduced net loading to 95 percent of normal rating.

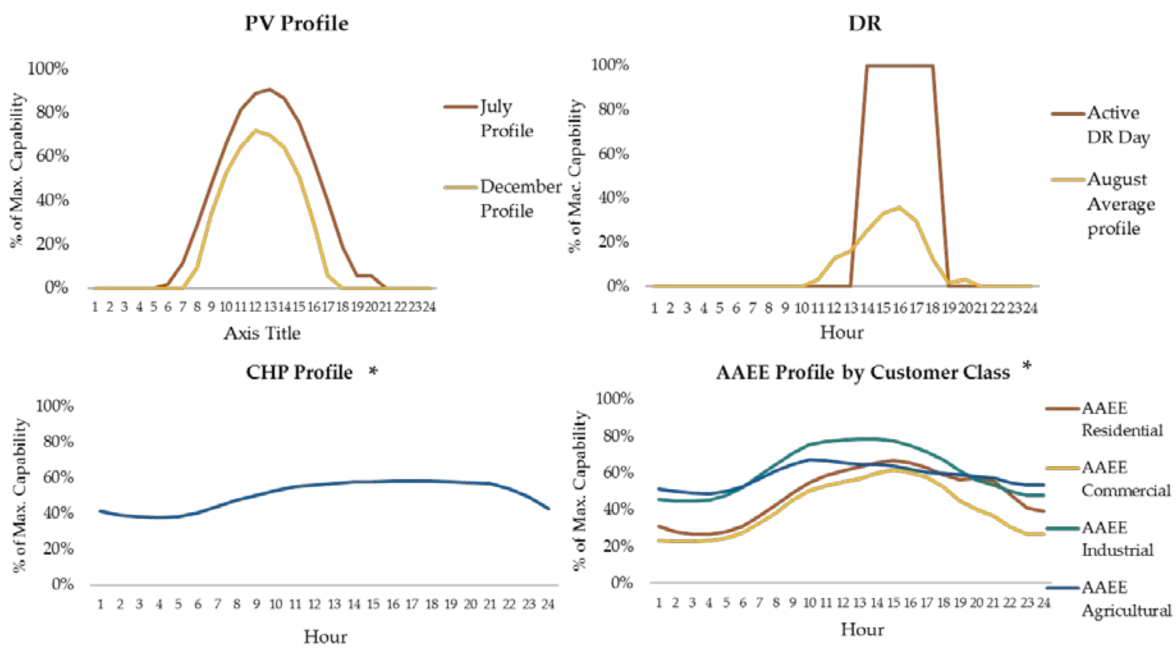
32 Because capacity deferral may occur for more than one year, it is important to accrue deferral benefits beyond the 10-year study horizon so as not to understate total benefits.

Firm DER Capacity

The ability of DER to defer transmission and distribution capacity investments is a function of the net firm capacity at the time of the transmission system and distribution peaks. Net firm capacity depends highly on the alignment of DER output and hourly profiles, particularly for solar when maximum output is during midday hours. For the network transmission system, net firm DER is a single value, often coinciding with the system peak. However, net firm DER varies for each distribution feeder and substation, as the amount of DER produced at the time of the feeder or substation peak also varies. For example, the amount of solar output for feeders that peak at 7:00 p.m. is far lower than feeders that peak at noon.

Figure 20 presents typical DER output hourly profiles for the SJV region. All profiles were provided by SCE based on its July DRP.

Figure 20: DER Output Profiles



Source: Navigant

Table 24 compares DER nameplate capacity versus firm output coincident with the feeder peak. The timing of the DER output is not necessarily coincident with feeder peak load. For example, SCE's DR programs in the SJV region are designed to reduce load at times of very high cost or emergencies and are called upon infrequently, not to reduce feeder peak loads.

San Joaquin Valley Region Feeders

There are potential capacity deferral benefits in the SJV region, as 43 feeders (about 18 percent) are forecasted to exceed thermal ratings by 2024, while another 27 are within 90 percent of normal maximum rating. **Figure 21** illustrates 2024 loading profiles for the 239 SJV region feeders.

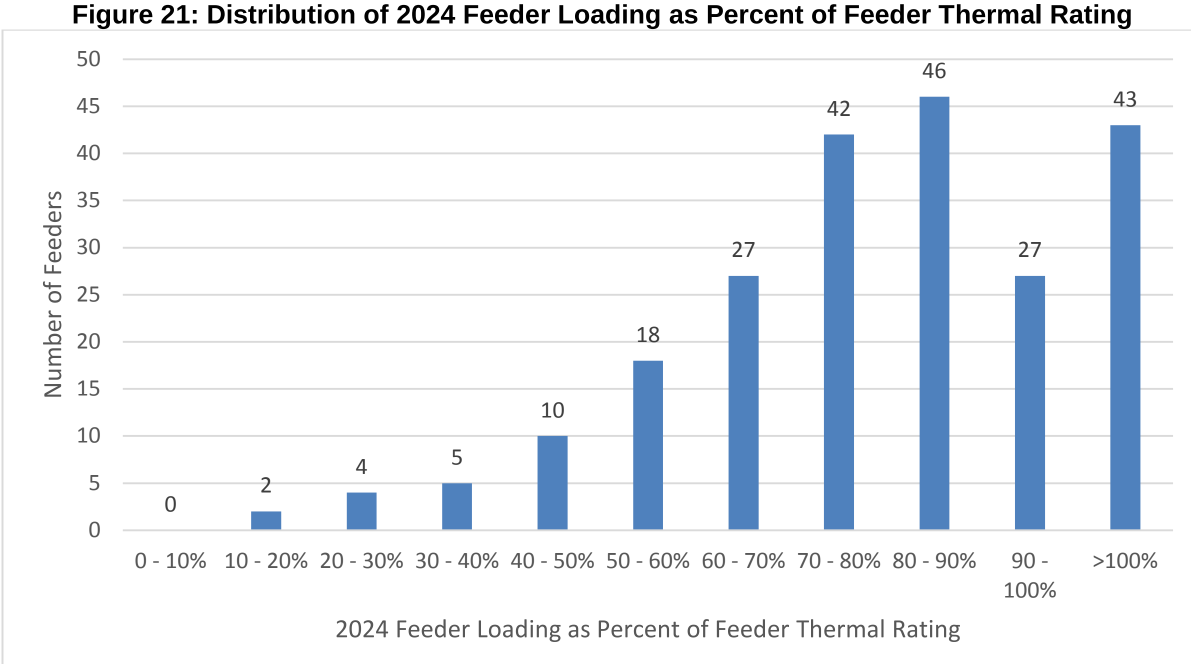
Table 24: DER Forecast for the San Joaquin Valley Region

	BAU Scenario (MW)		VA Scenario (MW)	
DER	**Nameplate Capacity**	**Coincident With Feeder Peak Load**	**Nameplate Capacity**	**Coincident With Feeder Peak Load**
AAEE	106.1	70.2	768	116.1
PV	38.7	10.6	190.8	56
CHP	4.6	2.8	51.6	31
DR	2.8	0.1	156.5	4.4
EV	-7.0	-5.2	-15.3	-5.2
ES	25.4	25.4	56.3	56.3
Total	**170.6**	**103.9**	**1207.9**	**258.6**

Note: EV values are negative to account for consumer charging

Source: Navigant analysis of SCE data

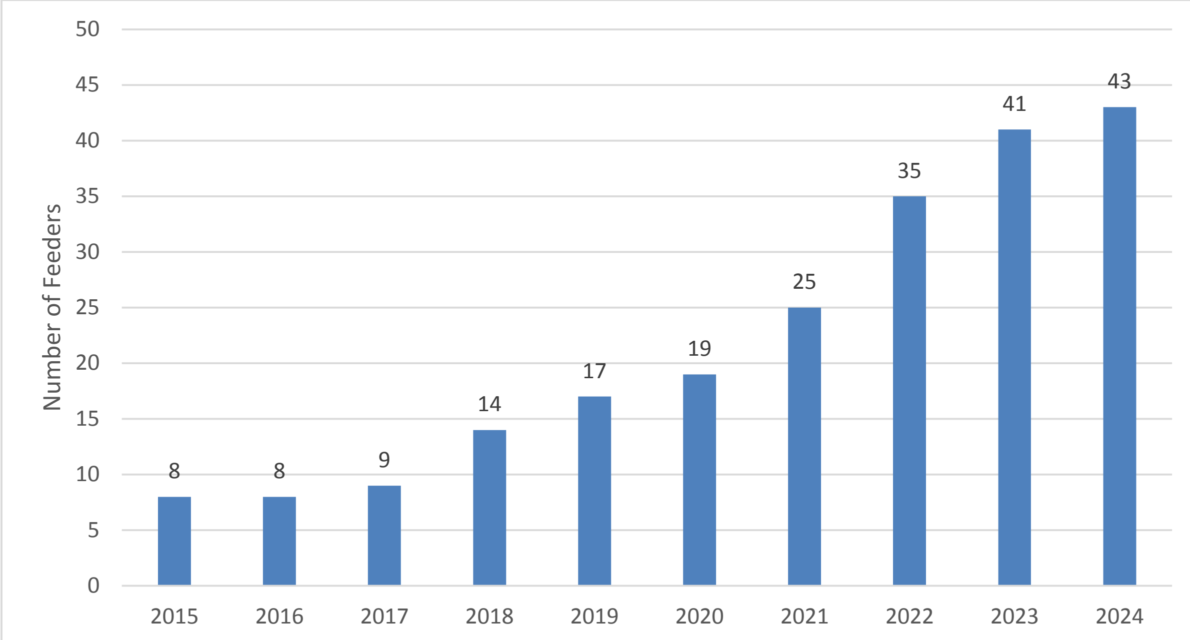
Figure 21: Distribution of 2024 Feeder Loading as Percent of Feeder Thermal Rating



Source: Navigant analysis of SCE data

Figure 22 presents the year in which feeders require upgrades on a cumulative basis. Upgrades are required as early as this year, with most after 2020. Given the gradual phase-in of DER capacity over the 10-year study time frame, most opportunities for deferral occur in later years.

Figure 22: Feeder Capacity Upgrade Requirements



Source: Navigant analysis of SCE data

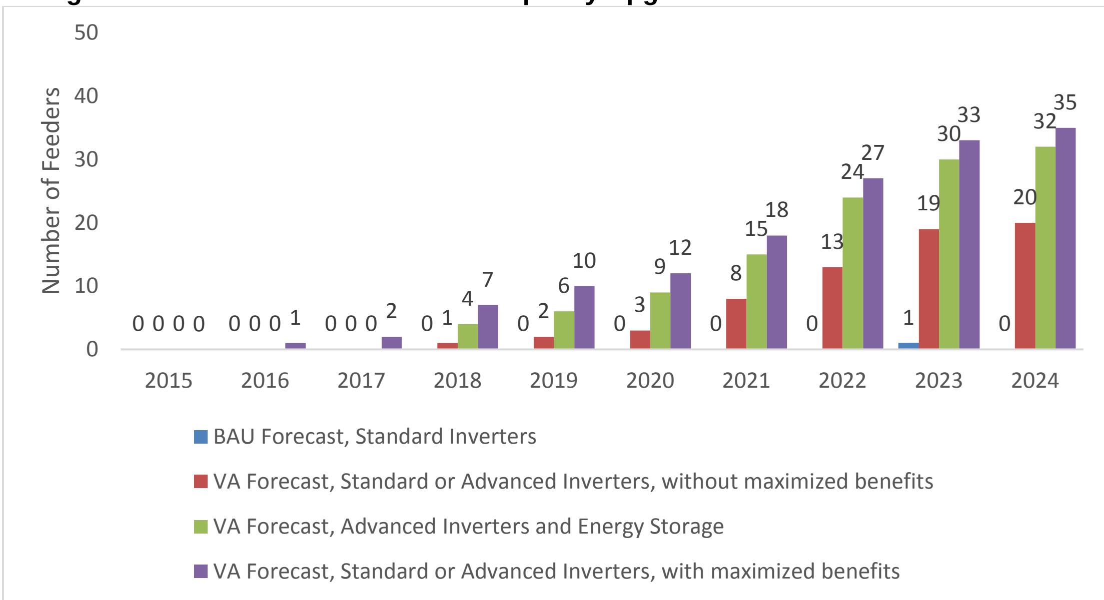
Capacity Deferral Analysis

The method the Energy Commission applied to determine potential substation and feeder capacity deferrals is consistent with SCE planning methods and criteria. (SCE provided firm DER capacity values for each DER resource.) To ensure sufficient DER is available to reliably defer capacity additions, an assumption was made that there must be sufficient firm DER capacity to reduce feeder peak loading to 90 percent of maximum normal rating. Using these criteria, the Energy Commission determined feeder capacity may be deferred from a low of 1 year to a maximum of 15 years, depending on future load growth and cumulative firm DER capacity.

Avoided Capacity Benefits

Figure 23 lists the number of feeders deferred annually for each of the six case studies. The number of deferrals is low in earlier years for all cases but increases significantly in the later years for Cases 2 through 6, each of which is based on the VA DER scenario. Case 1 produces very few deferrals, as the amount of firm DER is too low to sufficiently reduce net feeder load to 90 percent or lower. Case 4 has a higher level of capacity deferral under the assumption that storage is dispatched to reduce feeder peak; hence, the opportunities for deferral increase. Case 6 produces the highest deferral as it assumes optimal deployment of all DER; that is, to feeders that require capacity upgrades over the 10-year study time frame. **Table 25** summarizes the distribution benefits by case.

Figure 23: Number of Feeders with Capacity Upgrades Deferred at Least One Year



Source: Navigant

Table 25: 10-Year Cumulative Distribution Benefits by Case

Case	Case Name	Feeder Benefit	Transformer Benefit	Total Benefit
1	BAU Forecast, Standard Inverters	$0.1M	$0M	$0.1M
2	VA Forecast, Standard Inverters	$4.3M	$1.0M	$5.3M
3	VA Forecast, Advanced Inverters	$4.3M	$1.0M	$5.3M
4	VA Forecast, Advanced Inverters and Energy Storage	$9.1M	$1.1M	$10.2M
5	VA Forecast, Advanced Inverters With DER Targeted to Minimize Cost	$4.3M	$1.0M	$5.3M
6	VA Forecast, Advanced Inverters With DER Targeted to Maximize Benefits	$12.6M	$2.7M	$15.3M

Source: Navigant

Distribution Net Costs

Table 26 includes the installed cost of the DER, plus total interconnection cost (system upgrade and connection cost), less benefits for each analysis case. The resource cost is determined by multiplying the nameplate capacity of the DER (**Table 18**) by the installed cost (**Table 21**). The interconnection cost is from **Figure 18,** and the benefits are from **Table 21.**

Table 26: Distribution Net Costs Summary

Case	Description	Resource Cost ($M)	Interconnection Cost ($M)	Benefits ($M)	Net Cost ($M)
1	BAU Scenario, Standard Inverters	$180.9	$6.10	$0.10	$186.9
2	VA Forecast, Standard Inverters	$917.6	$55.80	$5.30	$968.1
3	VA Forecast, Advanced Inverters	$917.6	$16.70	$5.30	$929.0
4	VA Forecast, Advanced Inverters and Energy Storage	$917.6	$37.00	$10.20	$944.4
5	VA Forecast, Advanced Inverters With DER Targeted to Minimize Cost	$917.6	$14.20	$5.30	$926.5
6	VA Forecast, Advanced Inverters With DER Targeted to Maximize Benefits	$917.6	$37.00	$15.30	$939.3

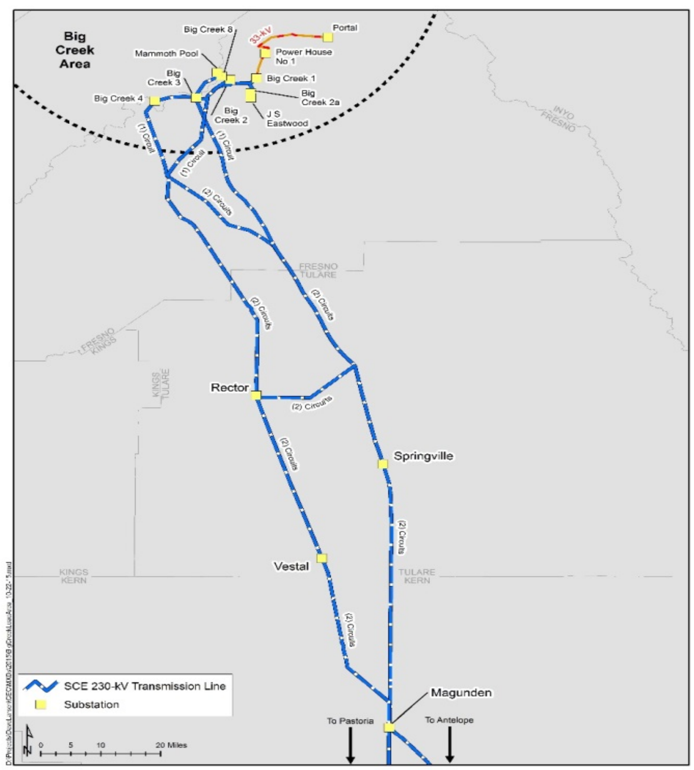
Source: Navigant

CHAPTER 4: Transmission Analysis

This chapter highlights DER impacts on the SCE transmission network in the SJV region. It includes all network lines operating 69 kV and above. All results are based on steady-state simulation studies using model databases for the region. The analysis focuses on 2024 impacts, when DER capacity and loads are highest. System upgrade costs include new facilities or implementation of remedial action schemes (RAS),[33] while benefits include transmission capacity deferral and reduced line losses.

The capability of the transmission network serving the SJV region depends on support provided by hydroelectric plants just north of the region, which collectively supply more than 1,000 MW at peak output. **Figure 24** illustrates the 230 kV lines serving the SJV region and the location of Big Creek and other nearby hydro plants.

Figure 24: San Joaquin Valley Region Transmission Network



Source: Navigant

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33 *Remedial action schemes* are adjustments to generation output or transmission line configuration by automation schemes or operator action to address postcontingency loading or voltage violations. RAS often is selected, when in compliance with reliability rules, in lieu of more costly system additions or upgrades.

Under normal hydrological conditions, the existing network along with existing generation and load shedding RAS that are used under contingency conditions can reliably serve the SJV region. However, current drought conditions have resulted in reduced output at Big Creek and other hydroelectric facilities in the region, which pose potential reliability issues on the regional transmission system. In addition, starting in 2016, revised North American Electric Reliability Corporation (NERC) Transmission Planning Standards (TPL 001-4) limit the amounts of load shedding for a single contingency to an amount up to 75 MW, about 25 percent of the levels presently being used (roughly 300 MW).

Method

Power-flow studies were performed using Positive Sequence Load Flow (PSLF) software to identify steady state and postcontingency impacts on the transmission system in the SJV region. The power-flow studies analyzed transmission system performance without and with DER to identify impacts and solutions to address these impacts.

To determine the impact of DER on transmission operations, Navigant:

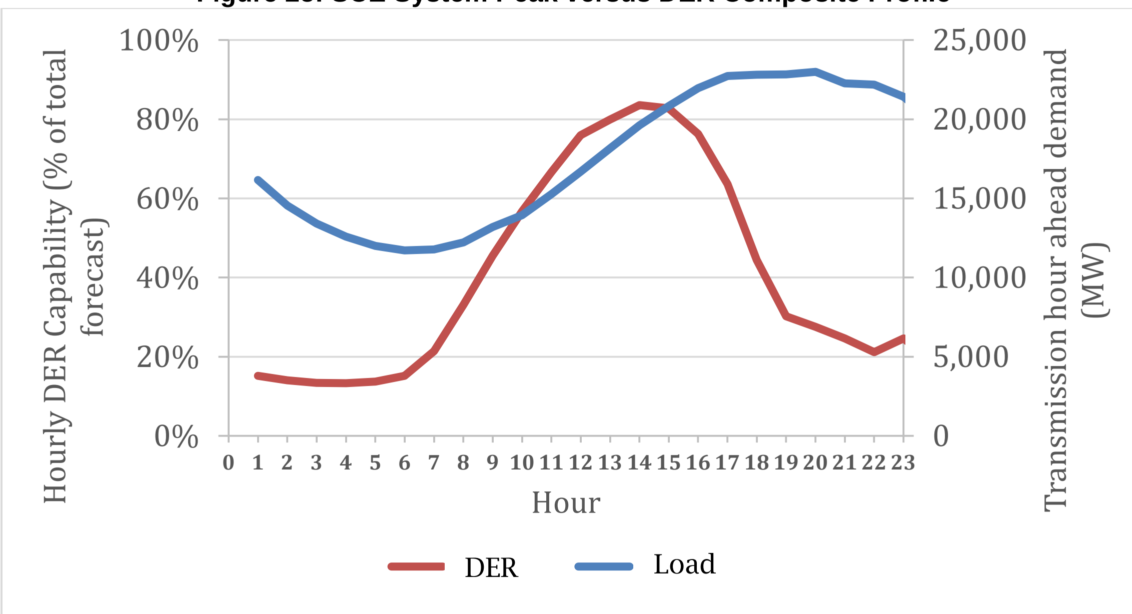
1. Obtained copies of two “Reference” power-flow base cases modeling 2025 peak loads in the SJV region that modeled two levels (“low” and “high”) of hydro generation in the Big Creek area from SCE. These cases did not model any DER in the region.
2. Obtained copies of the contingency files used to simulate P1 (Category B, Single Contingency) outages, P6 (N-1-1 or “overlapping” second contingency outages), and P7 (Category C common structure second contingency outages) outages from SCE.
3. Modified the two SCE “Reference” base cases to create four power-flow cases (“low” hydro/BAU DER, “low” hydro/VA DER, “high” hydro/BAU DER, and “high” hydro/VA DER). In these post-DER cases, it was assumed that the DER capacity is firm and available at the time of the system peak.
4. Conducted contingency studies for each of the “Reference” cases and for each of the four “Post-DER” cases to identify post-contingency issues (overloads, low voltages, and so forth) for both the reference and DER cases.
5. Compared the results of the “Reference Case” studies to those from the “Post-DER” cases to identify potential benefits/impacts associated with the assumed levels of DER.

Transmission System Assumptions

To address issues related to limited hydroelectric output, SCE, in conjunction with the California ISO’s ongoing transmission planning, is investigating the installation of thyristor controlled series capacitors (TCSC) on the Magunden-Springville No. 1 and No. 2 lines, and the Rector-Springville lines displayed in **Figure 24**. These devices are capable of preventing postcontingency line overloads that otherwise would occur if insufficient hydroelectric output is available. Since at the time of the simulations the studies were ongoing, the proposed TCSC additions were excluded from the transmission model and network studies.

The ability of DER to support the transmission system in the SJV region depends highly on the availability of these resources at the time of the area peak and other hours when support may be needed. **Figure 25**, which compares the DER profile versus hourly loads for SCE's September 2014 peak, demonstrates that DER output does not align with the SCE system peak. Hence, DER output is derated in the transmission model to reflect lower firm capability coincident with the area peak.[34]

Figure 25: SCE System Peak versus DER Composite Profile



Source: Navigant analysis of SCE data

Transmission Study Cases

To evaluate the capability of DER to provide support to the transmission system in the region the Energy Commission analyzed the transmission system under low and high hydroelectric output conditions. **Table 27** summarizes loads, generation, and firm DER modeled in the region and resultant power exports from the region for the six DER cases outlined in prior sections.

Transmission Analysis

Transmission studies included an assessment of network performance in the SJV region under low and hydro conditions for the BAU and VA DER Scenarios. The analysis evaluated transmission line loadings and voltages under normal, first contingency, and second contingency conditions; referred to as P0, P1, and P6/P7 events in transmission planning

34 The transmission analysis excluded shifting of energy storage output to align with the system peak, which could increase firm DER.

studies. All analyses are based on 2024 loads, generation levels, and DER output listed in **Table 27** and assumed that only 75 MW of load shedding RAS was available in the area.

Table 27: Transmission Case Studies

	Low Hydro Cases			High Hydro Cases		
	Reference	BAU Scenario	VA Scenario	Reference	BAU Scenario	VA Scenario
Loads (MW)						
Rector	849.8	849.8	849.8	849.8	849.8	849.8
Springville	309.4	309.4	309.4	309.4	309.4	309.4
Vestal	198.3	198.3	198.3	198.3	198.3	198.3
Big Creek	8.6	8.6	8.6	8.6	8.6	8.6
Total	1,366.1	1,366.1	1,366.1	1,366.1	1,366.1	1,366.1
Losses (MW)	70.6	55.8	39.3	51.1	52.5	57.0
Generation (MW)						
Big Creek	43.1	43.1	43.1	593.4	593.4	593.4
Eastwood	207.0	207.0	207.0	207.0	207.0	207.0
Mammoth	0.0	0.0	0.0	178.0	178.0	178.0
Small Hydro	0.0	0.0	0.0	130.6	130.6	130.6
Hydro	250.1	250.1	250.1	1,109.0	1,109.0	1,109.0
PV @ Vestal (New)	27.0	27.0	27.0	27.0	27.0	27.0
QF/Self[35]	586.0	586.0	586.0	745.0	745.0	745.0
Total	863.1	863.1	863.1	1,881.0	1,881.0	1,881.0
DER (MW)						
Rector	0.0	58.6	159.0	0.0	58.6	159.0
Springville	0.0	20.2	53.7	0.0	20.2	53.7
Vestal	0.0	24.8	49.1	0.0	24.8	49.1
Big Creek	0.0	0.3	1.5	0.0	0.3	1.5
Total	0.0	103.9	263.3	0.0	103.9	263.3
Exports (MW)	(573.6)	(454.9)	(279.0)	463.8	566.3	721.2

Source: Navigant

Low Hydro Conditions

Table 28 presents the results of the low hydro analysis, which shows several P1 (Single Contingency) and P6/P7 (Multiple Contingency) violations in the absence of DER[36]. In

35 Low hydro cases include 586 MW interconnected at Magunden. High hydro cases include 592 MW interconnected at Magunden and 153 MW interconnected at Vestal.

addition to overloads, four P1 outages for the reference case resulted in divergence, which is a non-solution load-flow outcome. Under the BAU Scenario, all P1 overloads are eliminated, and P6/P7 overloads are significantly reduced. When firm DER is increased to 350 MW, all overloads are reduced. Both levels of DER also mitigate the divergence (nonsolution) phenomena evident in the Reference cases.

Table 28: Transmission DER

	Transmission Overloads (%)					
Impacted Facility	**P1 O/L (Single Contingency)**			**P6/P7 O/L (Double Contingency)**		
	Reference (No DER)	**BAU DER Scenario (104 Firm MW)**	**VA DER Scenario* (350 Firm MW)**	**Reference (No DER)**	**BAU DER Scenario (104 Firm MW)**	**VA DER Scenario* (350 Firm MW)**
Magunden-Springville #2 230kV Line	None	None	None	Divergence	2%	None
Magunden-Vestal 230kV Lines	Divergence	38%	None	60%	36%	None
Vestal-Rector 230kV Line	15%	3%	None	Divergence	7%	None

*Increased from 263 MW to 350 MW to identify state at which no violations occur.

Source: Navigant

However, the time required to reach the firm DER levels cited above obviates the ability of DER to reduce overloads and voltage issues. As a result, mitigation of the near-term impacts needs to be achieved via other actions such as adding the TCSCs discussed above, which would address violations caused by low hydro to 2025.

The above finding suggests a combination of TCSCs and firm DER in the SJV region would be able reduce overload and voltage violations after 2025.[37] Accordingly, studies were conducted to assess how DER could provide longer-term support via the following strategy:

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36 The impacts noted in the Reference and BAU and VA Scenarios Cases occurred on 230 kV lines north of Magunden Substation. Because of the low hydro output from Big Creek units, there are significant amounts of power flow northward on these lines for the Reference Case (574 MW) and the BAU Scenario (455 MW).

37 Approximately 75 MW of load at Rector would need to be dropped at Rector for this solution to be viable to 2025.

1. Identify the amount of additional load in the SJV region that could be reliably served if the TCSCs were in service, 75 MW of load was dropped via RAS at Rector, and up to 350 MW of firm DER were available at the time of the regional peak.
2. Identify potential system upgrades that would be required if the loads in the SJV region were at the levels listed above if DER was not available, the TCSCs were in service, and 75 MW of load drop via RAS at Rector.

The results of these studies indicate that with up to 350 MW of DER available, 75 MW of load drop at Rector, and the TCSCs in service, regional load growth could increase without contingency loading or voltage violations as follows:

- To about 1,600 MW if 263 MW of DER was available: an increase of 230 MW and equal to a 2043-2044 time-frame level.
- To about 1,700 MW if 350 MW of DER was available: an increase of 330 MW and equal to a 2052-2053 time-frame level.

Absent DER, studies indicate that it would be necessary to add transmission facilities north of Magunden (such as a Magunden-Vestal #3 line and a Vestal-Rector #3 line) to maintain system reliability in the region to the 2052 time frame. The cost of these facilities could be substantial; preliminary estimated costs range from $260 million to $320 million.[38] Hence, the value of the deferral achieved by DER could be substantial.

High Hydro Conditions

For high hydro output conditions, the addition of DER capacity could result in transmission performance violations, including overloads on 230 kV lines south of Magunden for the VA Scenario.[39] The severity of these impacts is less than the low hydro output cases, as studies indicated that P6/P7 overloads of 8 percent would occur on the Magunden-Pastoria lines under the VA Scenario; the overload increases to 18 percent for the 350 MW DER case. (The BAU Scenario did not cause any violations.) The VA scenario overloads[40] could be addressed by expanding existing RAS to decrease Big Creek hydro output, which is more cost-effective than building new transmission facilities to reduce line overloads. Alternatively, sensitivity studies indicated P6/P7 overloads on the two Magunden-Pastoria lines could be eliminated if:

38 Estimated costs are based on information in SCE's "2015 SCE Unit Cost Guide".

39 Unlike low hydro conditions, which cause increases in northern flows, high Big Creek hydro output increases southward flows, 464 MW in the Reference Case to 721 MW for Scenario 3.

40 The expanded SPS/RAS would be used to reduce Big Creek hydro generation only during critical contingencies and not implemented during normal operating conditions.

- About 180 MW of firm DER is available at the time of the system peak.
- The amounts of hydroelectric generation on line in the Big Creek area was reduced by about 90 MW (about 8 percent), with 263 MW of DER (VA Scenario) available.

Transmission Losses

Transmission system losses in the SJV region depend highly on hydroelectric output and the level of firm DER capacity. **Table 29** presents area line losses for each DER scenario under low and high hydro output conditions.

Table 29: Transmission Line Losses

	Low Hydro				High Hydro			
	Reference	**BAU Scenario**	**VA Scenario**	**High DER**	**Reference**	**BAU Scenario**	**VA Scenario**	**High DER**
Loads (MW)	1,366.1	1,366.1	1,366.1	1,366 .1	1,366.1	1,366.1	1,366.1	1,366.1
DER (MW)	0.0	103.9	263.3	350.0	0.0	103.9	263.3	350.0
Generation (MW)								
Hydro	250.1	250.1	250.1	250.1	1,109.0	1,109.0	1,109.0	1,109.0
RAM PV	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
QF/Self	586.0	586.0	586.0	586.0	745.0	745.0	745.0	745.0
Total	863.1	863.1	863.1	863.1	1,881.0	1,881.0	1,881.0	1,881.0
Exports (MW)	(573.6)	(454.9)	(279.0)	(185. 8)	463.8	566.3	721.2	804.2
Losses (MW)	70.6	55.8	39.3	32.8	51.1	52.5	57.0	60.7
Change in Losses (MW)	-----	(14.8)	(31.3)	(37.8)	-----	1.4	5.9	9.6
Change in Losses (%)	-----	(21.0)	(44.3)	(53.5)	-----	2.7	11.5	18.8

Source: Navigant

Table 29 indicates DER reduces transmission losses for the low hydro cases due to lower regional net power imports. In contrast, DER increase transmission losses for the high hydro cases results due to higher net regional power exports.

Summary Assessment

The transmission studies conducted for the BAU and VA DER scenarios confirm that DER may provide substantial long-term benefits depending on local hydroelectric conditions. If the drought persists, DER, if installed in sufficient amounts with sufficient lead-time, could defer up to $320 million of 230 kV transmission upgrades beginning in 2025. Prior to 2025, short-term upgrades will still be required as sufficient amounts of firm DER will not be available to correct capacity deficiencies that exist today. Because the lead time for new transmission lines is between five and seven years, there would need to be firm commitments to install DER (DG and EE/DR programs) within the next few years in amounts sufficient for capacity deferral to realize these benefits.[41]

Further, the DER performance would need to be sustained over time, up to 2052, to capture maximum capacity deferral benefits. The amount of actual benefits also can vary depending on other factors, such as actual load growth in the region, hydro output that may be between the low and high output cases, installation of new local generation (for example, merchant plants), or new transmission construction by third parties. The latter two options could obviate benefits associated with DER.

41 For permitting, regulatory approval design, procurement construction and commercialization.

CHAPTER 5: Combined Transmission and Distribution Results

The prior two chapters presented transmission and distribution costs and benefits for two DER growth scenarios, the BAU scenario, and the VA scenario from SCE's July 2015 DRP. The VA scenario examines DER benefits and costs various combinations of DG inverter controls, energy storage and targeted DG. In this section, results are combined with DER installed cost to develop total net transmission and distribution interconnection benefits and cost.

Summary Results

Table 30, **Table 31**, **Table 32**, **Table 33**, **Table 34**, and **Table 35** present total net cost, including transmission and distribution benefits and costs, and DER cost for the BAU and VA DER growth scenarios for 10- year and 20-year timeframes. Two states of hydro output are considered, low and high, as potential benefits shift significantly for reasons outlined in the transmission section. Also, two time frames are analyzed for the low and high hydro cases to highlight the value of capacity deferrals over time. Importantly, transmission deferral benefits accrue after 2024, as short-term measures, including TCSCs outlined in the transmission section, must be installed to ensure area reliability is maintained for the first 10 years.

Related assumptions include the following:

- Cost of transmission capacity deferral is $260 million for 230 kV reinforcement (2025).
- DER degradation factors are not applied (DER capacity sustained over 10 to 20 years).
- Transmission interconnection cost for high hydro is zero (mitigated by SPS).
- Loss savings are based on a loss factor of 20 percent and avoided cost of $50/MWh in 2025.
- Discount rate of 10 percent and fixed charge rate of 15 percent are applied to transmission deferrals.

Table 30: BAU DER: Standard Inverters - Net Cost and Benefit

Big Creek Hydro	DER Horizon	Interconn. Cost ($M)	Dist. Cap. Deferral ($M)	Trans. Upgrade Deferral ($M)	Loss (Savings) / Cost ($M)	Net Cost / (Benefit) ($M)
Low	10	$6.1	($0.1)	($239.6)	($18.2)	($251.8)
Low	20	$6.1	($0.1)	($326.2)	($26.7)	($346.9)
High	10	$6.1	($0.1)	$0.0	$3.4	$9.4
High	20	$6.1	($0.1)	$0.0	$5.0	$11.0

Source: Navigant

Table 31: VA DER Scenario, Standard Inverters

Big Creek Hydro	DER Horizon	Interconn. Cost ($M)	Dist. Cap. Deferral ($M)	Trans. Upgrade Deferral ($M)	Loss (Savings) / Cost ($M)	Net Cost / (Benefit) ($M)
Low	10	$55.8	($5.3)	($239.6)	($18.2)	($207.3)
Low	20	$55.8	($5.3)	($326.2)	($26.7)	($302.4)
High	10	$55.8	($5.3)	$0.0	$3.4	$54.0
High	20	$55.8	($5.3)	$0.0	$5.0	$55.6

Source: Navigant

Table 32: VA DER Scenario, Advanced Inverters

Big Creek Hydro	DER Horizon	Interconn. Cost ($M)	Dist. Cap. Deferral ($M)	Trans. Upgrade Deferral ($M)	Loss (Savings) / Cost ($M)	Net Cost / (Benefit) ($M)
Low	10	$16.7	($5.3)	($239.6)	($18.2)	($246.4)
Low	20	$16.7	($5.3)	($326.2)	($26.7)	($341.5)
High	10	$16.7	($5.3)	$0.0	$3.4	$14.8
High	20	$16.7	($5.3)	$0.0	$5.0	$16.4

Source: Navigant.

Table 33: VA DER Scenario, Advanced Inverters and Targeted Storage

Big Creek Hydro	DER Horizon	Interconn. Cost ($M)	Dist. Cap. Deferral ($M)	Trans. Upgrade Deferral ($M)	Loss (Savings) / Cost ($M)	Net Cost / (Benefit) ($M)
Low	10	$37.0	($10.2)	($239.6)	($18.2)	($231.0)
Low	20	$37.0	($10.2)	($326.2)	($26.7)	($326.1)
High	10	$37.0	($10.2)	$0.0	$3.4	$30.2
High	20	$37.0	($10.2)	$0.0	$5.0	$31.8

Source: Navigant.

Table 34: VA DER Scenario - DER Located to Minimize Costs

Big Creek Hydro	DER Horizon	Interconn. Cost ($M)	Dist. Cap. Deferral ($M)	Trans. Upgrade Deferral ($M)	Loss (Savings) / Cost ($M)	Net Cost / (Benefit) ($M)
Low	10	$14.2	($5.3)	($239.6)	($18.2)	($248.9)
Low	20	$14.2	($5.3)	($326.2)	($26.7)	($344.0)
High	10	$14.2	($5.3)	$0.0	$3.4	$12.3
High	20	$14.2	($5.3)	$0.0	$5.0	$13.9

Source: Navigant.

Table 35: VA DER Scenario, DER Located to Maximize Benefits

Big Creek Hydro	DER Horizon	Interconn. Cost ($M)	Dist. Cap. Deferral ($M)	Trans. Upgrade Deferral ($M)	Loss (Savings) / Cost ($M)	Net Cost / (Benefit) ($M)
Low	10	$37.0	($15.3)	($239.6)	($18.2)	($236.1)
Low	20	$37.0	($15.3)	($326.2)	($26.7)	($331.2)
High	10	$37.0	($15.3)	$0.0	$3.4	$25.1
High	20	$37.0	($15.3)	$0.0	$5.0	$26.7

Source: Navigant.

Results for all scenarios indicate net cost depends highly on the outlook for Big Creek area hydro output. If the drought continues, DER, if installed in sufficient amounts with sufficient lead time, could defer up to $320 million of 230 kV transmission upgrades beginning in 2025 with significant net benefits thereafter. Prior to 2025, short-term upgrades will still be required as sufficient amounts of firm DER will not be available to correct capacity deficiencies that exist today. The amount of actual benefits also can vary depending on other factors such as actual load growth in the region, hydro output that may be between the low and high output cases, installation of new local generation (for example, merchant plants), or new transmission construction by third parties. The latter two options could obviate benefits associated with DER. Accordingly, actual benefits for transmission could range between the zero value assigned to the high hydro case and the $326 million for the low hydro output case.

Key Findings

Study findings indicated interconnection costs for DER in the SJV region are modest and can be reduced by initiating several candidate strategies. There are potential offsetting benefits that can further reduce net interconnection cost. Transmission benefits could be significant after 2024 if low hydro output in the region continues and sufficient firm DER is available to defer transmission upgrades that may be needed if other competing options are not pursued.[42]

Specific findings and conclusions follow.

- Distribution
  - The cost to interconnect DER ranges from zero to 10 percent of total installed cost of DER, up to $56 million for interconnection for the VA DER scenarios in 2024. Up to 20 to 40 percent of total interconnection costs are connection charges, which are nondeferrable.
  - Interconnection cost for the BAU DER scenario is less than 5 percent of total installed cost of DER, most of which is for connection, which is nondeferrable.
  - Many system upgrades are required to address voltage violations, some of which can be reduced via advanced inverter controls.
  - The cost of upgrades can be reduced by 50 percent or more by implementing smart controls on all inverters or by targeting DER to feeders where the cost of system upgrades is low.
  - About 10 percent of the 239 feeders require system capacity upgrades by 2024; of these, up to half can be deferred one year or more for the aggressive DER scenario.
  - Up to 75 percent of future distribution capacity upgrades can be deferred one year or more if energy storage is matched to solar devices or if DER is targeted to feeders where benefits may be contingent upon other measures and investments outlined in SCE's DRP.

42 Because the transmission network must be able to sustain single and double contingency events consistent with NERC requirements and California ISO reliability criterion, any single year with low hydro conditions could cause thermal or voltage violations. Thus, intermittent "low" and "high" hydro years would require transmission upgrades or DER capacity to maintain network reliability during any single year where hydro output is low.

- Transmission
  - The impacts of DER on the SJV region transmission system are modest if hydro output at nearby hydroelectric facilities returns to normal levels (currently experiencing drought conditions).
  - Most impacts resulting from the presence of DER when hydro output is at normal levels can be addressed by common mitigation options such as redispatch of generation when outages or other emergencies occur, which are infrequent.
  - The transmission system may benefit from DER if hydroelectric output from the Big Creek plant continues to be low beyond 2024; these benefits may be substantial, if other mitigation options are not undertaken.
  - Up to $320 million in transmission capacity deferral may be achieved over 20 years if sufficient amounts of reliable DER capacity is available.

Acronyms and Abbreviations

Acronym/Abbreviation	Original Term
AAEE	Additional achievable energy efficiency
BAU	Business as usual
CAGR	Compound annual growth rate
California ISO	California Independent System Operator
CHP	Combined heat and power
DER	Distributed energy resources
DG	Distributed generation
DR	Demand response
DRP	Distribution resource plan
EE	Energy Efficiency
Energy Commission	California Energy Commission
ES	Energy storage
EV	Electric vehicles
IEPR	Integrated Energy Policy Report
GWh	Gigawatt-hour
kV	Kilovolt
MW	Megawatt
NCP	Noncoincident Peak
NERC	North American Electric Reliability Corporation
PSLF	Positive sequence load flow
PV	Photovoltaic
QF	Qualifying facility
SCE	Southern California Edison
SJV	San Joaquin Valley
TCSC	Thyristor controlled series capacitors

Acronym/Abbreviation	Original Term
T&D	Transmission and distribution
VA	Very aggressive