Southern California Edison
A.09-09-022 – Alberhill PTC & CPCN

DATA REQUEST SET ED-Alberhill-SCE-JWS-2

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 3/4/2019

4/18/2019

Question 01b: Provide additional analysis as required by D.18-08-026, Ordering Paragraph 4, items 4.b, 4.e, and 4.h, replicated below:

b) Identification of all subtransmission planning areas in the SCE system with similar reliability issues;

Item B:

Identification of all subtransmission planning areas in the SCE system with similar reliability issues.

Response to Item B:

I. Introduction

As discussed throughout the Alberhill System Project (ASP) Certificate of Convenience and Necessity (CPCN) proceeding, the reliability issues in the Valley South System are associated with a combination of characteristics related to its limited capacity[1] margin, configuration, and size that make the Valley South subtransmission system[2] much more vulnerable to future reliability[3] problems than any other Southern California Edison (SCE) subtransmission system. Specifically, in its current status, the Valley South System operates at or very close to its maximum operating limits, has no connections (tie-lines) to other systems, and represents the largest concentration of customers on a single substation in SCE's entire system. These characteristics threaten the future ability of the Valley South System to serve load under normal conditions.

Also discussed in the proceedings, in the case of a catastrophic event (such as a major fire or incident at Valley Substation) SCE's ability to maintain service or to restore power in the event of an outage is significantly limited by the concentration of source power in a single location at Valley Substation. This characteristic, in combination with others described in this submittal, results in specific concerns for the Valley South System from a resiliency[4] perspective.

In responding to this data request, SCE has provided data on Valley South System characteristics that challenge reliability and/or resiliency, contributing to the likelihood of occurrence and/or impact of events that lead to loss of service to customers. These characteristics are compared to SCE's other 55 subtransmission systems and demonstrate that no other SCE subtransmission planning area has a similar cumulative combination of characteristics that lead to reliability and resiliency challenges the Valley South System faces.

II. Summary of Valley South System Reliability and Resiliency Issues

As introduced above, the Valley South System faces various challenges (*e.g.*, limited capacity margin, geographic size, number of customers served, configuration, *etc*.) which cumulatively make it uniquely vulnerable to reliability and resiliency problems and substantially compromise SCE's ability to adequately serve its customer's electrical demands under both normal and abnormal system conditions. Table 1 describes nine characteristics correlated with reliability and resiliency. Some of these characteristics contribute to events that lead to loss of service to customers while others relate more to the number of customers that would be impacted by an event or the ability of SCE to take prompt actions to recover from such an event. Table 2 compares SCE's subtransmission systems across those nine characteristics.

---

[1] *"Capacity"* is defined as the availability of electric power to serve load and is primarily comprised of two elements in a *radial transmission system*; a lack of capacity of either type will lead to reliability challenges in a radial subtransmission system: (1) "*transformation capacity"* – the ability to deliver power from the transmission system (through substation transformers); and (2) "*subtransmission system line capacity"* – the ability to deliver power to substations which directly serve the customer load in an area. Subtransmission system line capacity also includes "*tie-line capacity,*" which is the ability to transfer load to an adjacent subtransmission system to avoid, and reduce the number of customer's affected by, planned and unplanned outages in the system. Note, a *radial subtransmission system* is one that is provided power from a single source on the transmission system. This is in contrast to a networked system which has multiple transmission and subtransmission source connections. Almost all of SCE's subtransmission systems are of a radial design.

[2] While Southern California Edison typically considers a planning area to be at the substation level, for the purpose of this data request, the discussion herein focuses on Valley South, as it is most relevant to the Alberhill System Project (ASP) proceedings. Certain characteristics discussed here may have broader impacts (on the Valley North System specifically, given the split nature of these systems), but the focus of this response remains on the Valley South System.

[3] "*Reliability*" is defined as a utility's ability to meet service requirements under normal and N-1 contingency conditions, both on a short-term and long-term basis. The ability to meet long-term capacity needs of a given system is an important aspect of reliability. This definition is consistent with IEEE 1366, "*IEEE Guide for Electric Power Distribution Reliability Indices"* which excludes extraordinary events from reliability data reporting.

[4] *"Resiliency"* is defined as how well a utility anticipates, prepares for, mitigates, and recovers from effects of extraordinary events (such as wildfires, earthquakes, cyberattacks, and other potential high impact, low probability (HILP) events) which can have widespread impact on its ability to serve customers. This definition is consistent with IEEE PES-TR65 "*The Definition of Quantification of Resilience*" (April 2018).

The discussion and data below demonstrate that no other SCE subtransmission planning area faces reliability and resiliency challenges similar to the Valley South System; that is, the ability of the Valley South System to reliably serve load under both normal and extraordinary event conditions is currently threatened more so than any other subtransmission planning area. As electrical demand grows in the Valley South System, the existing reliability and resiliency concerns will increase. The peak demand served by the Valley South System is expected to exceed capacity by 2022[5], impacting SCE's ability to provide continuous, safe and reliable electrical service to each of the approximately 500,000 people and critical customers served therein. SCE proposed the ASP to address the major drivers of the reliability and resiliency challenges facing the Valley South System by providing transformation capacity, system tie-lines and an additional connection to the bulk transmission system to diversify the source of power from Valley Substation.

A. Reliability

As suggested by Tables 1 and 2, the cumulative effect of the listed characteristics impacts the Valley South System's reliability and threatens SCE's ability to serve load under normal system conditions. For example, the Valley South System currently operates at or very close to its maximum operating limits and has the smallest remaining available transformation capacity of any SCE subtransmission system (Characteristic 3). The Valley South System capacity margin is limited to an extent that makes it the only subtransmission system in the SCE service territory with a temporary operating procedure to place an installed, spare transformer in-service during times of high demand.[6] The Valley South System is also one of two fully built out 1,120 MVA systems (the other is the Valley North System), resulting in no ability to add transformer capacity on a permanent basis to address even a modest amount of load growth (Characteristic 4). Further, the Valley South System is the only SCE subtransmission system without system tie-lines (*i.e.*, zero tie-line capacity) to other SCE electrical systems, making it completely isolated from the larger SCE system (Characteristics 5 and 6). Finally, the Valley South System represents the largest concentration of customers on a single substation in SCE's entire system (Characteristics 7 and 8), significantly magnifying the consequence of reliability events at Valley Substation and the ability to mitigate such events.

B. Resilience

The Valley South System also has characteristics that make it more difficult to plan for, mitigate and recover from an extraordinary or catastrophic event (such as an earthquake, major fire, malicious act, or major incident at Valley Substation) that could result in a sustained outage over a longer period of time. This is the basis for the resiliency concern. For example, the installed transformer capacity of 1,120 MVA (equaling the Valley North System as the largest in SCE's service territory), suggests that a significant amount of load may not be served in the event of an extraordinary event (Characteristic 1). Further, as discussed above, SCE's ability to maintain service or to restore power in the event of a catastrophic event is significantly limited by the concentration of source power in a single location at Valley Substation with zero system tie-lines (Characteristic 5). Additionally, the Valley South System's unique 500/115 kV transformers limit the ability to share and promptly procure and/or install replacement transformers[7] in the event of catastrophic system failures (Characteristic 6). The exceptionally large number of regular and "critical" customers served by the Valley South System (Characteristics 7 and 8) also affects SCE's ability to limit the impact of a catastrophic event. The Valley South System has high levels of peak demand (1-in-5 heat storm adjusted value of 1,083 MVA in 2017), reflecting the magnitude of significant consequences an extraordinary event may have on SCE's customers (Characteristic 2). Finally, the large service area (Characteristic 9) of the Valley South System[8] could complicate personnel and equipment staging efforts during the recovery from an extraordinary event.

III. Data

Table 1 describes system characteristics that contribute to both the likelihood of occurrence and impact of events that challenge reliability or resiliency, respectively.

Table 2 quantitatively compares the reliability and resiliency related characteristics for the Valley South System and the other 55 SCE subtransmission systems. Values highlighted in red identify characteristics that may be negatively associated with reliability and/or resiliency.

---

[5] Based on the SCE 2018-2027 forecast, the Valley South System load is expected to exceed its transformer capacity in 2022 with no further capacity additions possible within the design limits of the substation.

[6] The Valley South System is the only subtransmission system in the SCE service territory with a temporary operating procedure to place an installed, spare transformer in-service during times of high demand. Normal condition, long-term and short-term load ratings are used by SCE grid operators to ensure that transformer temperature ratings are not exceeded during normal and temporary overload conditions. Based on these ratings, it is not permissible to operate the two Valley South System transformers with load over 896 MVA because the instantaneous loading that would be placed upon one transformer during an unplanned outage of the other would be beyond the short-term rating, exposing the transformer to potential damage or catastrophic failure. This limitation is why SCE has developed and implemented mitigation through a temporary operating procedure which places an installed spare transformer in-service with the two load-serving transformers any time the Valley South System load approaches 896 MVA (80% of the system capacity). During an unplanned outage of one of the two load-serving transformers, the entire loading of the system is placed on the one remaining transformer. The maximum allowable loading value is 160% of the nameplate value of 560 MVA, or a total of 896 MVA. 896 MVA is 80% of the 1,120 MVA of nameplate capacity of the system. Thus, because the Valley South System is without tie-lines to allow transfer of load, Utilization Percentage in excess of 80% can be considered a threshold at which reliability is a concern in the Valley South System. The 2017 (1-in-5 year) Peak Utilization Percentage is shown in Table 2 to be 97%. Please refer to data request response to Item H for discussion of why in-servicing this spare transformer is not a permanent solution to the capacity shortfall.

[7] 500/115 kV transformers at Valley Substation (two each for the Valley North and South Systems respectively) are unique within SCE and rare in the industry. Long lead times for replacement, and logistics implications of transporting these large transformers are considerations relevant to both reliability and resiliency. SCE maintains an adequate inventory of spare 230/115 kV and 230/66 kV transformers for its standard A-bank substations which transform between these voltages. As such, they can be sourced, transported and installed in just a few days when needed in the case of a failure event. SCE maintains one off-site spare 500/115 kV transformer and one installed spare that is currently used to meet the criteria requirement of an on-site spare but that also is functioning as short-term mitigation of overload conditions per the temporary operating procedure discussed above. Further, because these transformers are an atypical design, large and expensive, they are only manufactured to order when needed. Thus, in the event of a failure or need to replace a spare that is put into service due to a capacity shortfall, a lead time of a year or more is likely to be required to source a replacement. In addition (even when a spare transformer is available off-site), logistics, transportation, installation and in-servicing of these much larger 500/115 kV transformers will take several more days to implement than is the case for a 230/115 kV or 230/66 kV transformer.

[8] While the Valley South System has a smaller service territory size than four other systems (*i.e.*, the Antelope, Rector, Vestal, and Victor Systems), these systems serve sparse rural areas with significantly less load than the Valley South System.

Table 1 – Substation and System Characteristics: Correlation to Reliability & Resiliency

CHARACTERISTIC	DESCRIPTION	SIGNIFICANCE TO RELIABILITY	SIGNIFICANCE TO RESILIENCY
1. Installed Transformer Capacity	The currently installed nameplate capacity of the in-service transformers which serve a system. This demonstrates the current load-serving capacity of the system.	This characteristic typically reflects the load being served by the system. A larger system is not inherently more or less reliable than a smaller capacity system *per se* as long as operating margin is maintained. However, a larger installed transformer capacity could improve reliability of a system if margin exists and tie-lines are available to transfer load from other systems to avoid/manage the impact of an outage on an adjacent system.	Larger installed transformer capacity is not a resiliency issue in and of itself. However, it is a direct reflection of the number of customers and amount of load that would be unserved in the event of an extraordinary event that could render all or part of the substation out of service. If tie-lines to adjacent systems are available and tie-line capacity margin is maintained, capacity at neighboring substations would aid system resiliency by allowing transfer of load from adjacent systems in the event of an extraordinary event.
2. Peak Demand	The 2017 weather adjusted peak demand (1-in-5 heat storm) of the system.	High levels of peak demand are more likely to outstrip the operating margin of a given system, hindering the ability to meet load demands and thus negatively impacting system reliability. In the event that demand exceeds a system's operating capacity, system operators are forced to transfer load through the use of system tie-lines, or to shed load.	High levels of peak demand also indicate an increased potential to negatively impact a system's resiliency. The peak demand of a system is a direct reflection of the potential impact an extraordinary event may have on customers (*e.g.*, if that event were to take a substantial portion of the substation or associated transmission lines out of service). The greater the peak demand, the greater the anticipated impact to that system's customers in the event of an extraordinary event.
3. Ultimate System Design Capacity & Utilization Percentage	This characteristic represents the Ultimate System Design Capacity and the amount of Ultimate Design Capacity Utilized expressed as a percentage (derived by dividing Peak Demand by Ultimate System Design Capacity).	This characteristic is a critical element from a reliability perspective. A high utilization percentage indicates that transformer capacity will be exceeded with a modest amount of load growth. When load growth exceeds transformer capacity, system operators are forced to transfer load through the use of system tie-lines, or to shed load. Having sufficient capacity to serve load is a critical element to ensure system reliability.	A high utilization percentage limits the amount of reserve capacity that could be utilized to accept load during an extraordinary event in a neighboring system, should system tie-line capacity be available.

Table 1 – Substation and System Characteristics: Correlation to Reliability & Resiliency

CHARACTERISTIC	DESCRIPTION	SIGNIFICANCE TO RELIABILITY	SIGNIFICANCE TO RESILIENCY
4. Available Design Capacity	This characteristic represents the remaining amount of transformer capacity that could be installed for the system before reaching its design limit. It is the difference between Ultimate System Design Capacity and Installed Transformer Capacity.	A system with greater available design capacity allows a utility to address load growth simply by installing transformers in an existing substation. If available, this capacity lowers the risk of capacity shortfalls that could affect reliability.	Limited available design capacity indicates that a substation or system is operating close to its maximum design limit. SCE design practices limit the amount of design capacity and therefore demand that is served from a systems and substations, which helps manage the impacts should an extraordinary event occur. This approach serves to minimize negative impacts to system resiliency.
5. Number of Tie-Lines [9]	The number of ties-lines within the system which connect to adjacent systems.	System tie-lines improve reliability. System tie-lines allow for the operational flexibility to maintain service during unplanned equipment outages, during planned maintenance and construction activities, and to pre-emptively transfer load to avoid loss of service to customers. System tie-lines can effectively supplement transformation capacity by allowing the transfer of load to adjacent systems. Conversely, systems which are isolated, and which do not have system tie-lines cannot rely on available capacity of adjacent systems. A system with higher tie-line capacity can transfer more customers and load than a system with lower tie-line capacity. In addition to correlating with higher overall tie-line capacity (*see* above), a greater number of tie-lines provides more options for system operators to transfer specific distribution substations to "work out of" contingencies that could otherwise adversely affect reliability.	Reduced system tie-line capacity negatively impacts resiliency by preventing system operators from having the flexibility to transfer large numbers of customers (*via* entire distribution substations) during catastrophic events which have widespread system impacts. This can complicate the recovery efforts from an extraordinary event, since system tie-lines offer system operators the ability to easily restore service to parts of an impacted system, thus allowing them to focus on parts of the system which cannot be transferred. An increased number of tie-lines leads to increased tie-line capacity and improves resiliency by providing more load transfer options for system operators to plan for and mitigate the impact of extraordinary events that can affect a large portion of a system.

[9] The number of tie-lines is an important characteristic in itself and, for the purpose of this submittal, serves as a surrogate characteristic representing tie-line capacity since the amount of available tie-line capacity in a system is dynamic and cannot be reported as a firm number. The amount of tie-line capacity in a system can be described by two factors: (1) the capacity determined by the rating of the actual electric facilities (*e.g*., conductors and associated equipment) of the lines, and (2) the capacity determined by the amount of additional power the lines can accommodate (under abnormal system conditions) in addition to any load they already serve. System tie-lines are typically normal subtransmission circuits that are connected to substations providing power on a regular basis ("native load"); but which also have one or more connections to adjacent systems through "normally open" sectionalizing devices such as open switches or open circuit breakers. The native load they serve typically must remain being served even when the system tie-lines are used to provide load transfers from an adjacent system. This amount of native load changes as loading at the distribution system level changes and is also based on other system conditions such as configuration changes. As such, the capacity of additional power a particular system tie-line can accommodate is dynamic but is always no more than the rating of the electrical facilities themselves. Thus, tie-line capacity is the difference between the electric facilities rating of the subtransmission line, and the amount of native load being served during the time of the needed transfer. Clearly however, a system with no tie-lines has zero tie-line capacity.

Table 1 – Substation and System Characteristics: Correlation to Reliability & Resiliency

CHARACTERISTIC	DESCRIPTION	SIGNIFICANCE TO RELIABILITY	SIGNIFICANCE TO RESILIENCY
6. Voltage Classification	The voltage classification of equipment (*e.g.*, transformers, switchrack, subtransmission lines) affects the equipment's physical size, cost, and commonality.	Adjacent systems with similar voltage classifications are generally more reliable because they can readily support load-transfers (*via* system tie-lines). Similar voltage classifications also facilitate equipment sharing (*i.e.*, a spare 220/66 kV transformer may be used at any number of facilities provided the applicable voltage classifications of the system are the same). Equipment sharing reduces the need for on-site spare transformer requirements at each facility and rather, allow multiple facilities to share the same spare equipment.	System resiliency is enhanced by the ability to share spare equipment (transformers in particular) and place them into service. Systems with disparate voltage classifications cannot share transformers or other critical equipment. Adjacent systems which have disparate voltage classifications cannot rely on each other during recovery from extraordinary events because it is less practical from a design standpoint to include system tie-lines.
		The procurement time, cost, and the ability to mobilize, transport, prepare, and place electrical equipment in-service may negatively impact the reliability of a system. Larger, less common transformers have longer lead times for installation in the event of transformer failure. For example, a spare 220/66 kV transformer can typically be mobilized within hours of an identified need. In contrast, mobilizing a 500/115 kV transformer, if available, requires special permits, handling, and transport vehicles for delivery. Once the need is identified, delivery of a replacement 500/115 kV transformer may take days depending on location and availability of the specialized transport vehicles required.	Resiliency is adversely affected when it is prohibitively expensive to maintain inventory of large, uncommon spares sufficient to deal with an extraordinary event that takes a number of transformers out of service. Resiliency is also negatively impacted when larger equipment requires special logistical efforts to move into place. Such equipment, even if available, takes longer to procure and put into service, hindering the impacted system's full and timely recovery.
7. Number of Metered Customers	The number of metered customers served by the system as of 2017.	While uncommon during normal operation, subtransmission level outage events will affect more customers in a system with a larger number of metered customers. A larger number of customers increases the impact of reliability issues.	Large radial subtransmission systems have more customers at risk subject to long term outages in an extraordinary event that could disrupt the delivery of power.
8. Number of Critical Customers	The number of critical customers served by the system.	Ensuring that the short-term power needs of critical customers are met is an important element of reliability. Critical customers are likely to be affected when a system is challenged by lack of capacity and is required to shed load.	Resiliency includes addressing the impact and consequence of extraordinary events. The consequence of an extraordinary event that could disrupt the delivery of power through the radial subtransmission system for a significant time period is more pronounced for critical customers, and a large number of critical customers makes it more challenging to prioritize critical customers for return to service following an extraordinary event.
9. Size of Area Served	The approximate service area in square miles that contains customers that the system serves.	Larger service area sizes can negatively impact system reliability. The size of a system's service area affects the amount of time needed to recover from common system outages in that the dispatch of service crews to identify and remedy system issues in large service areas typically takes longer than smaller service areas.	Larger service area sizes can also negatively impact a system's resiliency. A larger area of service may increase the complexity of staging people and equipment and associated recovery efforts from an extraordinary event.

Table 2 – SCE Subtransmission Electrical System Comparison[10]

Electrical System[11]	1. Installed Transformer Capacity (MVA)	2. Peak Demand (2017 MVA, 1-in-5 Heat Storm)	3. Ultimate System Design Capacity & Utilization Percentage		4. Available Design Capacity (MVA)	5. Number of Tie-Lines	6. Voltage Classification (kV)	7. Number of Metered Customers	8. Number of Critical Customers	9. Size of Area Served. (Approximate Square Miles)
			Capacity in MVA[12]	% of Capacity Utilized						
Alamitos	560	203	1,120	18%	560	6	220/66	83,414	646	17
Antelope	840	619	1,120	55%	280	3	220/66	137,775	3497	568
Bailey	530	46	1,120	4%	590	2	220/66	5,896	113	40
Barre AB	560	538	560	96%	0	6	220/66	127,068	1610	45
Barre C	280	257	560	46%	280	4	220/66	57,908	826	21
Center A	280	168	560	30%	280	1	220/66	33,633	360	12
Center B	490	377	560	67%	70	5	220/66	75,675	1225	28
Chino	840	861	1,120	77%	280	10	220/66	149,849	2121	79
Del Amo A	280	231	560	41%	280	4	220/66	49,247	1106	18
Del Amo C	560	379	560	68%	0	4	220/66	80,729	1188	29
Devers	840	481	1,120	43%	280	4	220/66	99,297	2142	222
Eagle Rock	560	271	1,120	24%	560	12	220/66	61,545	183	10
El Casco	560	200	1,120	18%	560	4	220/66	28,404	791	39
El Nido	560	376	1,120	34%	560	6	220/66	87,300	408	21
Ellis A	560	374	560	67%	0	3	220/66	109,380	1551	33
Ellis C	560	333	560	60%	0	4	220/66	97,430	545	30
Etiwanda W	280	488	560	87%	280	3	220/66	73,686	1619	52
Etiwanda E	560	242	560	43%	0	2	220/66	36,442	1078	25
Goleta	560	329	1,120	29%	560	3	220/66	85,049	301	76
Gould	560	162	1,120	14%	560	3	220/66	25,478	301	17
Hinson	560	621	1,120	55%	560	5	220/66	86,522	518	25
Johanna	560	462	1,120	41%	560	8	220/66	78,672	330	25
Kramer	530	196	1,120	17%	590	6	220/66	39,961	1015	269
La Cienega	560	525	1,120	47%	560	7	220/66	111,223	353	30
La Fresa A	560	331	560	59%	0	3	220/66	97,714	498	32
La Fresa B	530	375	560	67%	30	1	220/66	110,926	816	37
Laguna Bell AB	530	310	560	55%	30	6	220/66	54,948	384	16
Laguna Bell DE	530	326	560	58%	30	1	220/66	57,780	204	16
Lighthipe AB	280	266	560	48%	280	2	220/66	55,809	464	22
Lighthipe DEF	560	308	560	55%	0	5	220/66	64,529	774	25
Mesa	840	717	1,120	64%	280	10	220/66	173,772	1191	59
Mira Loma	840	794	1,120	71%	280	6	220/66	107,025	2278	97
Mirage	840	458	1,120	41%	280	2	220/66	69,557	1126	46
Moorpark A	560	355	560	63%	0	3	220/66	55,317	772	88
Moorpark C	560	533	560	95%	0	3	220/66	82,975	808	132

[10] Values highlighted in red identify characteristics with the most extreme value that may be negatively associated with reliability and/or resiliency. SCE notes that with respect to Characteristic 3, SCE has highlighted the highest two extreme values (associated with Valley EFG (South) and the Vista C systems). This is because the Vista C System is dedicated solely to provide power to the City of Riverside Public Utilities municipality. During times of peak demand, the City of Riverside utilizes peaking generation to meet load values that would otherwise be above the installed transformer capacity and to bring the actual utilization percentage down to below 100%. The Valley South System ranks 2nd (1st when excluding Vista C because of the peak shaving generation present) in terms of the highest utilization percentage of the 56 systems and does not have peak-shaving generation resources.

[11] Typically, when a third transformer bank is needed at an A-bank substation, the existing facilities are divided into two separately operated systems (termed a "split system") with each system being served by two transformers. There are several reasons for this activity including issues related to reliability and resiliency (how many customers are affected when a system event occurs) and short-circuit current values that increase beyond equipment ratings when three or four transformers operate electrically in parallel. "Split systems" are generally referred to using their substation electrical bus section designations (*e.g.*, Moorpark A and Moorpark C). The Valley ABC bus section is generally known as the Valley North System, and the Valley EFG bus section is generally known as the Valley South System. Currently there are twelve substations with "split systems": Barre, Center, Del Amo, Ellis, Etiwanda, La Fresa, Laguna Bell, Lighthipe, Moorpark, Santiago, Valley, and Vista.

[12] With the exception of Valley North and Valley South, for each of the systems listed with 1,120 MVA of "Ultimate System Design Capacity," these systems will be split into two 560 MVA systems by the time they reach 1,120 MVA of capacity (or four transformers at the substation). This results in Valley ABC (North) and Valley EFG (South) as the only two 1,120 MVA systems.

Table 2 – SCE Subtransmission Electrical System Comparison[10]

Electrical System[11]	1. Installed Transformer Capacity (MVA)	2. Peak Demand (2017 MVA, 1-in-5 Heat Storm)	3. Ultimate System Design Capacity & Utilization Percentage		4. Available Design Capacity (MVA)	5. Number of Tie-Lines	6. Voltage Classification (kV)	7. Number of Metered Customers	8. Number of Critical Customers	9. Size of Area Served. (Approximate Square Miles)
			Capacity in MVA[12]	% of Capacity Utilized						
Olinda	560	471	1,120	42%	560	4	220/66	85,758	1575	36
Padua	840	796	1,120	71%	280	8	220/66	131,992	2535	62
Rector	840	818	1,120	73%	280	2	220/66	130,583	3703	466
Rio Hondo	920	804	1,120	72%	200	4	220/66	142,216	1548	61
San Bernardino	840	612	1,120	55%	280	3	220/66	121,230	2630	96
Santa Clara	840	602	1,120	54%	280	6	220/66	177,929	1552	288
Santiago A	560	453	560	81%	0	6	220/66	89,882	599	48
Santiago C	560	460	560	82%	0	5	220/66	91,148	1004	49
Saugus	840	887	1,120	79%	280	5	220/66	146,306	2115	161
Springville	480	248	1,120	22%	640	7	220/66	43,369	737	283
Valley ABC (North)	1,120	800	1,120	71%	0	4	500/115	141,277	4262	286
Valley EFG (South)	1,120	1,083	1,120	97%	0	0	500/115	187,274	5787	380
Vestal	560	245	1,120	22%	560	5	220/66	36,543	636	395
Victor	840	526	1,120	47%	280	3	220/66	139,439	4974	382
Viejo	560	402	1,120	36%	560	4	220/66	71,040	1268	36
Villa Park	840	804	1,120	72%	280	8	220/66	152,953	2280	62
Vista	560	418	560	75%	0	6	220/115	61,581	2006	93
Vista A	560	273	560	49%	0	2	220/66	33,790	786	40
Vista C	560	640	560	114%	0	2	220/66	109,300	0	82
Walnut	840	768	1,120	69%	280	7	220/66	128,422	1911	59
Windhub	560	88	1,120	8%	560	5	220/66	18,125	472	63