ecology and environment, inc.

Date:	March 27, 2017
To:	Jensen Uchida, CPUC Environmental Division Nicholas Sher, CPUC Legal
From:	Ecology and Environment, Inc.
Re:	Memorandum on [1] Electrical Forecasting in the Project Area for the Valley-Ivyglen Project and Alberhill System Project and [2] Project Objectives and Alternatives for the Proposed Alberhill System Project

1.0 Introduction

This memorandum was prepared to provide background information to support the CPUC's responses to comments received during the public review period for the Alberhill System Project (ASP)/Valley Ivyglen (VIG) Project Draft Environmental Impact Report (DEIR). It will be included in the Final EIR for the ASP/VIG Projects. The purpose of this memorandum is to provide support for the following determinations made by the CPUC in its capacity as Lead Agency under the California Environmental Quality Act (CEQA):

1. SCE's load forecasting methodology is based upon established industry methodology;
2. The ASP and VIG project objectives are sufficient as a basis for the development and analysis of a reasonable range of alternatives to the respective proposed projects pursuant to CEQA; and
3. The Valley Substation expansion alternative and the interconnection alternatives were eliminated from further consideration under CEQA because these alternatives did not meet the project objectives of the ASP project.

1.1 Purpose of the Valley-Ivyglen Project

The purpose of the VIG Project is to improve the reliability of the existing single 115-kV subtransmission line connection between Fogarty and Ivyglen substations as well as to eliminate the potential for 115-kV system overloads resulting from the loss of a 115-kV component within the Electrical Needs Area (ENA). The proposed Valley-Ivyglen 115-kV Subtransmission Line would relieve loads on the existing Fogarty-Ivyglen 115-kV Subtransmission Line and provide a second source of power to Ivyglen Substation by creating a second 115-kV connection between Valley Substation and Ivyglen Substation. Increasing the applicant's ability to transfer load between 115-kV substations in the ENA would increase operational flexibility and would enable the applicant to provide safe and reliable electrical service within the ENA.

For the VIG Project, the CPUC has identified the following project objectives for purposes of CEQA review:

1. Serve projected electrical demand requirements in the ENA;
2. Increase electrical reliability to ENA by providing a direct connection between the Applicant's Valley 500/115-kV Substation and Ivyglen 115/12-kV Substation; and
3. Improve operational and maintenance flexibility on subtransmission lines without interruption of service.

As described in Chapter 1.0, Introduction, of the DEIR, the analysis of the VIG Project is a response to an amended Petition for Modification (PFM) filed by Southern California Edison (SCE) for a previously approved VIG project. According to SCE, the VIG Project is necessary because the ENA has been experiencing power outages. According to SCE, as of September 8, 2016, there were three outages—one on the Valley-Elsinore-Fogarty 115kV Subtransmission Line and two on the Fogarty-Ivyglen 115 kV Subtransmission Line. These outages affected customers served by SCE's Fogarty and Ivyglen Substations (as each substation is served by the same single source line).

SCE maintains that these outages would have been avoided had the Valley-Ivyglen 115 kV Subtransmission Line been in-service and that delays in implementing the VIG Project will likely result in increases in electrical outages in the ENA in the future. The remainder of this memo is focused on the ASP. Given that the VIG Project has been previously approved by the Commission, all of the alternatives for the ASP assume construction of the VIG Project, including nonsubstation alternatives.

1.2 Purpose of the Alberhill System Project

The purpose of the proposed ASP is to relieve projected electrical demand that would exceed the operating limit of the two existing load-serving Valley South 115-kV System 500/115-kV transformers by constructing a new 500/115-kV substation (i.e., Alberhill Substation) within the ENA. The proposed Alberhill Substation would allow for the provision of safe and reliable electrical service pursuant to North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards. System ties between a new 115-kV System (i.e., the proposed Alberhill 115-kV System served by the proposed Alberhill Substation) and the existing Valley South 115-kV System would be maintained such that either system could be used to provide electricity. Thus, no loss of power would result where maintenance, emergency events, or the need to relieve other operational issues renders one system inoperative.

SCE proposed the ASP as a 500/115-kV substation because the most expedient method of bringing a large amount of electricity directly into the ENA is to tap the existing Serrano-Valley 500-kV line, immediately north of the proposed ASP substation site. According to SCE, such a project would provide a new source of power and reduce the electrical losses associated with transporting power from the congested Valley Substation. Considering that the existing electrical system in the ENA operates at 115-kV, it was evident to the CPUC team that a 500-kV loop-in and a new 500/115-kV substation represented a reasonable method of relieving projected electrical demand.

Further, the CPUC was aware of the extensive siting constraints in the area related to transmission line construction based on the CEQA environmental review for the VIG Project. Note that constraints are such that although the VIG Project had previously been approved by the CPUC, it could not be constructed as approved due to topography constraints and concerns over impacts to jurisdictional drainages, among other reasons, thus resulting in SCE's PFM for the VIG Project. In addition, the project area contains extensive land managed by other agencies, including U.S. Forest Service Land, Bureau of Land Management Land, and Riverside County Habitat Conservation Agency (HCA). The area also includes HCA Core Reserve Land for Stephen's Kangaroo Rat (a federally Endangered species) and designated and eligible State Scenic Highways. In addition, the load center to be served by the ASP is primarily located in the Lake Elsinore area. Therefore, the power supply to relieve electrical demand for this rapidly growing area would logically be located near the load center in order to reduce the electrical line losses associated with transporting power over greater distances. One of the current problems with the Valley South System is the inefficiency associated with transporting all of the power for the current ENA from the Valley Substation. Given that the Lake Elsinore area and portions of the ENA further northwest along the I-15 corridor are located further from the Valley Substation, and these areas are projected to grow substantially in the near future, it is not logical to continue serving these areas from a single 500-kV substation, which currently supports both the Valley North and Valley South Systems.

Consistent with these circumstances, the project objectives for purposes of CEQA review are articulated as follows:

1. Relieve projected electrical demand that may exceed the operating limit of the two load-serving Valley South 115-kV System 500/115-kV transformers;
2. Construct a new 500/115-kV substation within the ENA that provides safe and reliable electrical service pursuant to NERC and WECC standards; and
3. Maintain system ties between a new 115-kV System and the Valley South 115-kV System that enable either of these systems to provide electricity in place of the other during maintenance, during emergency events, or to relieve other operational issues on one of the systems.

Note that although it was evident to the CPUC team that a 500-kV substation would be necessary to relieve projected electrical demand, the CPUC nonetheless evaluated a number of non-substation alternatives, as documented in the Alternatives Screening Report (Appendix D of the EIR). These alternatives met none of the project objectives.[1]

During public review of the DEIR, several commenters stated that the project objectives for the Alberhill Project were too narrow, which they claim limited the alternatives analysis in the EIR to only 500-kV substation alternatives. The CPUC analyzed and documented a number of non-substation alternatives in the Alternatives Screening Report, but these non-substation alternatives met none of the project objectives and therefore were eliminated from further analysis. While it may appear that the alternatives screening process favored substation alternatives, the explanation for the lack of non-substation alternatives in the DEIR is that none of the substation alternatives identified met any of the project objectives.

In addition, some non-substation alternatives would require SCE to purchase larger quantities of power due to the significant electrical losses that would result from transporting large amounts of power over greater distances. These alternatives do not meet any of the project objectives and raise concerns about the inefficient transport of electrical energy and indirect impacts related to increased reliance on power generation, which is out of alignment with California energy efficiency goals.

[1] Note that the original Alternatives Screening Report suggested that the Valley Substation upgrades (Alternative E) had been eliminated for failing to meet Objectives 2 and 3. The report further stated incorrectly that Alternative E would meet Objective 1. This mistake was corrected in the revised version of the Alternatives Screening Report. Alternative E has therefore been eliminated on the basis of failing to meet any of the project objectives.

2.0 Electrical Load Demand

During the original planning process, the applicant identified growth in electrical demand in the Valley South system from 2005 through 2007, and despite a decrease in electrical demand in 2008, the applicant forecasted that demand would continue to grow through 2022. In 2012, the recorded peak demand was 928 megavolt ampheres (MVA). Based on the increase in electrical demand from 2008 through 2012, and data indicating continued growth in Riverside County, the applicant determined that electrical demand would continue to increase through 2023. Therefore, in the DEIR, the applicant forecasted that peak electrical demand for a 1-in-5-year heat storm could increase to 1,144MVA by 2019, exceeding the operating limit of the two Valley South 500/115-kV transformers.

During the public review period for the DEIR, commenters expressed concern about the accuracy of SCE's projected load forecasts and suggested that SCE had improperly over-estimated future demand in the ENA. The CPUC's position is that such comments fail to consider the major economic setbacks that occurred during the recession and the housing crisis that began around 2008. Further, such comments are based on a fundamental misunderstanding of established methodologies for energy forecasting.

Nonetheless, to test the accuracy of such comments, after publication of the DEIR, the applicant provided the CPUC with updated load forecasts and recorded peak demand from 2015 and 2016, which appear to support their original assertion that electrical demand will continue to rise, in spite of data showing a decrease in electrical demand in 2008. Per Table 1-1, updated with the applicant's most recent load data, the recorded peak demand from 2005 through 2007 rose from 753MVA through 909MVA. Thereafter, the recorded peak demand fell to 787MVA in 2008 before rising relatively consistently beginning in 2009.

Table 1-1: Recorded and Projected Peak Demand in Megavolt Amperes for the Valley South 115-kV System (2005 to 2024)

Recorded Peak Demand	2005	2006	2007	2008	2009
Operating Limit	1119	1119	1119	1119	1119
Recorded Peak Demand	753	853	909	787	829
Projected Peak Demand, 1-in-5 Year Heat Storm	807	885	1038	1062	1057
Recorded Peak Demand (2010 to 2014)	2010	2011	2012	2013	2014
Operating Limit	1119	1119	1119	1119	1119
Recorded Peak Demand	894	924	928	879	925
Projected Peak Demand, 1-in-5 Year Heat Storm	968	1014	1027	1020	1055
Projected Peak Demand (2015 to 2019)	2015	2016	2017	2018	2019
Operating Limit	1119	1119	1119	1119	1119
Recorded Peak Demand	881	936	--	--	--
Projected Peak Demand, 1-in-5 Year Heat Storm	1045	1066	1090	1119	1114
Project Peak Demand (2020 to 2024)	2020	2021	2022	2023	2024
Operating Limit	1119	1119	1119	1119	1119
Project Peak Demand, 1-in-5 Year Heat Storm	1169	1193	1219	1244	1269

Source: SCE 2014
Key: Kv = kilovolt
Note: (a) Projected demand for a 1-in-5 year heat storm exceeds operating limit of Valley South 115-kV System.

The 122MVA dip in recorded peak demand in 2008, as mentioned above, is attributable to the financial crisis. In fact, the recession hit the Lake Elsinore area particularly hard, resulting in more foreclosures than any other community in the region.[2] As a result, SCE's previous load projections appeared to be high when compared to actual demand; however, as the area recovered from the crisis, loads returned and new forecasts are back in line with original projections.[3] Although certain years have recorded less peak demand, there is no expectation that increases in peak demand will occur consistently each year. Instead, when taken together over time, the expectation is that overall electrical demand in the ENA will increase. In fact, recorded peak demand between 2005 and 2016 demonstrates that electrical demand is increasing in the ENA.

2.1 Load Forecasting Methodology

Load forecasts were prepared for each delivery point based on actual peaks experienced and corrected for change in temperature for the one-in-five year peak load. The forecasts were made in concert with local municipal and planning staff to include new housing and commercial developments and station services to alternative generation sites. In addition, load reductions attributable to conservation activities were also included in the forecasts. SCE provided the following explanation of load forecast calculations in response to a CPUC data request:[4]

> To arrive at the calculated normal-weather and 1-in-5 heat storm peak loading values, SCE's performs a regression analysis of load versus temperature to determine the expected rate of change of load due to each degree change in temperature. For the Valley South 115 kV System, for the years 2004-2012 there was an observed 1.6% change in load for each degree Fahrenheit change in temperature. Beginning in 2013, the value was revised to be 1.9% change in load for each degree change in temperature to more accurately reflect the representative value of this relationship. This is termed the "temperature sensitivity" of the substation. Each year SCE documents the peak temperature and calculates the rolling average of these annual peak temperatures (typically over 20+ years). Each year a recorded peak electrical demand value is selected and the corresponding temperature on that day. This peak demand value is then weather-normalized to reflect the expected value had the temperature on that day been equal to that of the rolling average peak temperature. The weather-normalized value is the product of the recorded peak demand value, the number of degrees in temperature differential, and the temperature sensitivity and is seen in the formula below.
>
> <u>Weather-Normalized Peak Demand = (Rec. Peak Demand)(Temp. Differential x Temp. Sensitivity)</u>
>
> Once a weather-normalized value is obtained, a 1-in-5 year heat storm value is then calculated. This represents a day with a peak temperature that is 4 degrees Fahrenheit above the rolling average annual peak temperature value. As stated above, for the years 2004 – 2012 the temperature sensitivity was 1/6% per degree and the resulting calculation is:
>
> $$4°\text{F} \times 1.6\,\frac{\%}{°\text{F}} = 0.064\%$$

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[2] In January 2008 alone, one in five homes in the Lake Elsinore area were seized by banks. Fox, Zach. "HOUSING: Neighborhoods emptying in Lake Elsinore, region's foreclosure capital."

[3] See DEIR Table 1-1. Recorded and Projected Peak Demand in Megavolt Amperes for the Valley South 115-kV System (2005 to 2024).

[4] Data Request Set A.09-09-022 ED-SCE-Alberhill-01 Q.01 Response. Southern California Edison. August 17, 2016.

For the years after 2012, the temperature sensitivity was value was revised to be 1.9% per degree and the multiplier is 1.076:

$$4°\text{F} \times 1.9\frac{\%}{°\text{F}} = 0.076\%$$

2.2 Forecast Results

Table 1-2 and 1-3 are based on power flow analyses[5] generated using General Electric's Powerflow program. The CPUC's independent engineering consultant further analyzed the data by inputting it into industry standard software Positive Sequence Load Flow (PSLF) to model the power flows under normal and abnormal conditions.[6] These values were documented and compared to the maximum operating limits of existing equipment to determine if the flows would exceed the equipment's rating.[7]

As detailed above, SCE projects nearing the upper limit of available load in the ENA as early as 2018. Looking forward, SCE projects that there will be energy shortfalls during a 1-in-5 year heat storm as early as 2019, and energy shortfalls under normal conditions by 2025.

SCE follows the Western Electricity Coordination Council (WECC) and the North American Electrical Reliability Corporation (NERC) criteria for service over 100-kV, i.e., that all one-in-five year heat storm peak loads be served even if one line or transformer is taken out of service. Without reinforcement, several possible outages may result in unacceptably low voltage and line overloads throughout the 115-kV system. Moreover, there is a potential for cascading outages, which may interrupt electrical service to many substations and loads. As indicated in the most recent power flow analysis shown below (Figure 1), under normal conditions the system is already at 80% to 90% capacity.

[5] *Supra* n. 3.
[6] *Supra* n. 3. Normal conditions were used to establish a "base case" while abnormal conditions were those representing service or equipment outages.
[7] *Supra* n. 3.

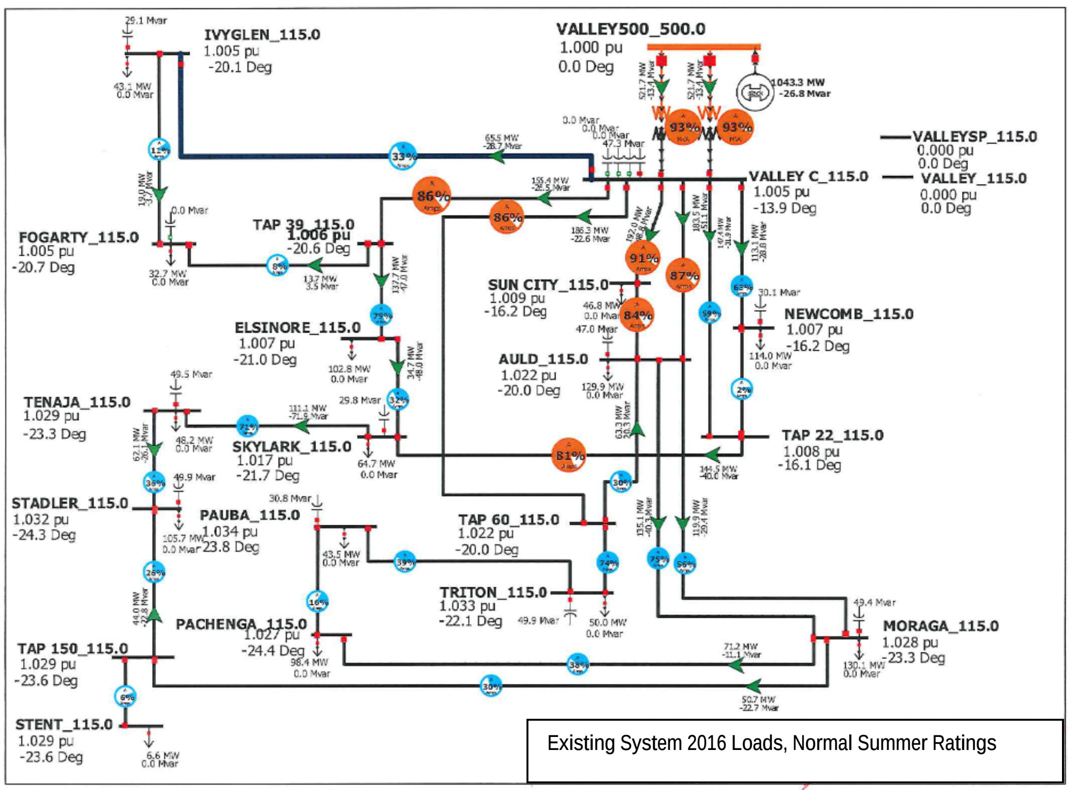
Table 1-2: Historical System Capacity of the Valley South 115-kV System (2004 to 2016)

Valley South 115-kV System													
2016 – 2026 Planning Period-Preliminary	System Capacity												
	Historical												
Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Capacity	1119	1119	1119	1119	1119	1119	1119	1119	1119	1119	1119	1119	1119
Peak Demand, Recorded	658	753	853	909	787	829	894	924	928	897	925	881	936**
Adjusted Normal Weather	703	777	874	944	817	867	921	934	923	960	951	940	987**
Adjusted 1-in-5 Year Heat Storm	748	827	930	1004	869	922	980	994	982	1033	1023	1011	1062**
Projected Normal Weather*	704	758	832	976	998	993	909	953	965	948	980	972	950
Projected 1-in-5 Year Heat Storm	749	807	885	1038	1062	1057	968	1014	1027	1020	1055	1045	1022
Surplus/Deficit (Capacity 1-in-5 Heat Storm)	370	312	234	81	57	62	151	105	92	99	64	74	97
Note: Preliminary data from SCE's 2017-2016 forecast. Assumes same load growth as 2016-2025 forecast. * Projected values (2004 – 2016) represent the projected values from the first year of the respective prior 10-year forecast. ** Preliminary data for 2016 subject to change once peak summer loading season is over. Note that peak summer loading runs through September, while the data represented in this table runs through August. *** Preliminary forecasted data for 2017-2026 subject to change based on final 2016 peak demand and changes to load growth. Note that September in the project area frequently experiences greater demand than August; therefore, by using data from August to calculate future load growth, it is possible that future demand has been slightly underestimated. Updated August 2016									10-year Compound Average Growth Range (2017 – 2026) = 1.41%				

Table 1-3: Projected Demand on the Valley South 115-kV System (2017 to 2026)

Valley South 115-kV System										
2016 – 2026 Planning Period-Preliminary	System Capacity									
	Projected									
Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity	1119	1119	1119	1119	1119	1119	1119	1119	1119	1119
Peak Demand, Recorded	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Adjusted Normal Weather	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Adjusted 1-in-5 Year Heat Storm	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Projected Normal Weather*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Projected 1-in-5 Year Heat Storm	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Peak Demand Projected – Normal Weather (Preliminary)*** →	1007	1024	1042	1061	1070	1080	1089	1105	1121	1137
Peak Demand Projected – 1-in-5 Heat Storm (Preliminary)*** →	1083	1102	1121	1141	1152	1162	1172	1189	1206	1223
Surplus/Deficit (Capacity 1-in-5 Heat Storm)	36	17	(2)	(22)	(33)	(43)	(53)	(70)	(87)	(104)
Note: Preliminary data from SCE's 2017-2016 forecast. Assumes same load growth as 2016-2025 forecast. * Projected values (2004 – 2016) represent the projected values from the first year of the respective prior 10-year forecast. ** Preliminary data for 2016 subject to change once peak summer loading season is over. *** Preliminary forecasted data for 2017-2026 subject to change based on final 2016 peak demand and changes to load growth. Updated August 2016							10-year Compound Average Growth Rate (2017 – 2026) = 1.14%			

Figure 1: Normal System Power Flow Analysis



3.0 Selected Non-Substation Alternatives

3.1 Valley Substation Expansion

Considering the load forecasts for the ASP Project, several considerations support the decision not to bring the Valley Substation expansion alternative forward for analysis in the DEIR.

The WECC and NERC planning criteria require the provision of continuous service during an outage of any one line or transformer. Adding additional capacity at the Valley Substation does not mitigate against outages in the Valley South 115-kV system and therefore fails to meet this requirement, and fails to meet the project objectives, which require that the project relieve projected electrical demand that may exceed the operating limit of the two load-serving Valley South 115-kV System 500/115-kV transformers. There will be seven transmission lines leaving the Valley Substation serving the Valley South area after the Valley-Ivyglen line is complete. Under this arrangement, should one line go out of service the electric load will flow to parallel lines and cause them to exceed their ratings and would eliminate voltage support at the station (i.e., would exceed the operating limit of the load-serving transformers). Moreover, if the parallel line is removed to avoid sag violations or equipment damage, the resulting cascading outages will leave wide areas without electric service. When the impacts are evaluated on a larger scale, removing the Valley-Ivyglen line from service during peak load will result in overloads on the Fogarty line and low voltages at the Fogarty substation.

Second, fitting the transformers and line into the existing bus arrangement at the Valley Substation would be difficult irrespective of land available at the site. Fitting the additional transformer and lines into the bus would necessitate a large substation rebuild and, as such, would likely result in long outages during construction. Note that there is insufficient physical space to connect all necessary equipment including transformers located at both the 500-kV and 115-kV switch racks. Additionally, the existing 115-kV line corridors are highly restricted where they exit the Valley Substation, and any additional lines would require multiple circuits on the same structure, complicating maintenance procedures. Therefore, rebuilding the substation would not relieve corridor constraints near the substation.

Third, adding a third 500/115-kV transformer to the Valley Substation would increase the current flowing into the circuit and exceed the interrupting rating of the circuit breakers. This could cause failures or explosions in the breakers, leading to wide area outages, equipment damage, and personal hazard. Even under normal conditions, the addition of a transformer at the Valley Substation would necessitate line replacements.

By comparison, the proposed Alberhill Substation achieves the primary project objective of meeting projected electrical demand in several ways. First, the Alberhill substation provides capacity near the load center of Lake Elsinore, deferring the need for subsequent additions within the 20-year planning window. Second, the proposed Alberhill substation provides effective backup for the 500-kV and 115-kV transformers at the Valley Substation so that they will not exceed their operating limits. Note that the 115-kV circuit breakers at the Valley Substation are only rated to clear faults for the existing configuration.

In addition to meeting the project objective of meeting projected electrical demand, the powerflow studies show that the proposed Alberhill Substation reduces system power losses by approximately 5 megawatts.

Given the cost of new energy, the loss savings will encompass a large portion of the cost of a new substation and reduce or avoid the need for purchases of new generation resources.

In summary, the Valley Substation is a large developed substation located in a constrained area. Therefore, while theoretical expansions of the substation may seem viable in the abstract, in reality, in light of the aforementioned load forecasts, it is impractical to continue indefinitely modifying and adding capacity to a single 500-kV substation while also achieving improved electrical reliability. Reliable electrical service requires that power be decentralized so that no one substation carries the entire load.

3.2 Interconnection with Other Areas

Commenters have also raised the possibility of connecting the 115-kV bus at the Valley Substation to the new Inland Empire Energy Center (IEEC) or connecting to the 230-kV Moraga Substation at the southern end of the Valley South area. The latter arrangement would connect to the San Diego Gas and Electric (SDG&E) system over the mountains.

First, it is unclear whether the IEEC could incorporate the additional transformers needed for a 115-kV interconnection. However, even if the transformers could be constructed, very high capacity would be required due to the higher impedance of lower voltage connections running in parallel with the 500-kV connections. Moreover, most of the new generation would flow in along the 500-kV lines and would not relieve the load on the 500/115kV lines sufficiently to delay the need for additional transformer capacity. Overall, this configuration would result in similar issues as described above under 3.1, Valley Substation Expansion, because in essence this alternative is a variation of the same alternative, which is an attempt to expand the capacity of the Valley Substation. As stated above, expanding the Valley Substation does not improve electrical reliability.

A Moraga-San Diego 230-kV system tie would fail to alleviate the need for additional capacity for similar reasons. Under this arrangement, power would flow from the Valley South area into the San Diego system, providing support to the San Diego system rather than the Valley System. Delivery of power to San Diego would not meet any of the proposed projects' objectives. Specifically, present cases assume the retirement of many coastal once-through cooling generation facilities due to estuary warming restrictions. The differential caused by these closings will result in power flowing from the Valley South System into the San Diego system. As a result, the Moraga connection would provide support to the 115-kV system (primarily Pechanga and Sadler substations), but would not reduce the load on the 500/115-kV transformers at the Valley Substation sufficiently to delay a 500-kV transformer addition somewhere in the ENA. In order to alleviate this problem, additional capacity would be required in the SDG&E territory, which is well beyond the scope of this project. In addition, a 500-kV line might also be required to connect the Valley Substation to the San Diego system near San Clemente. This, too, is far beyond the scope of the project.

Neither the proposed IEEC nor the proposed Moraga connections would relieve projected line overloads and low voltages on the Valley South system. See Figure 2 and Figure 3 below for visual representations of the IEEC and Moraga base cases developed based on independent power flow analysis.

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Figure 2: IEEC Interconnection

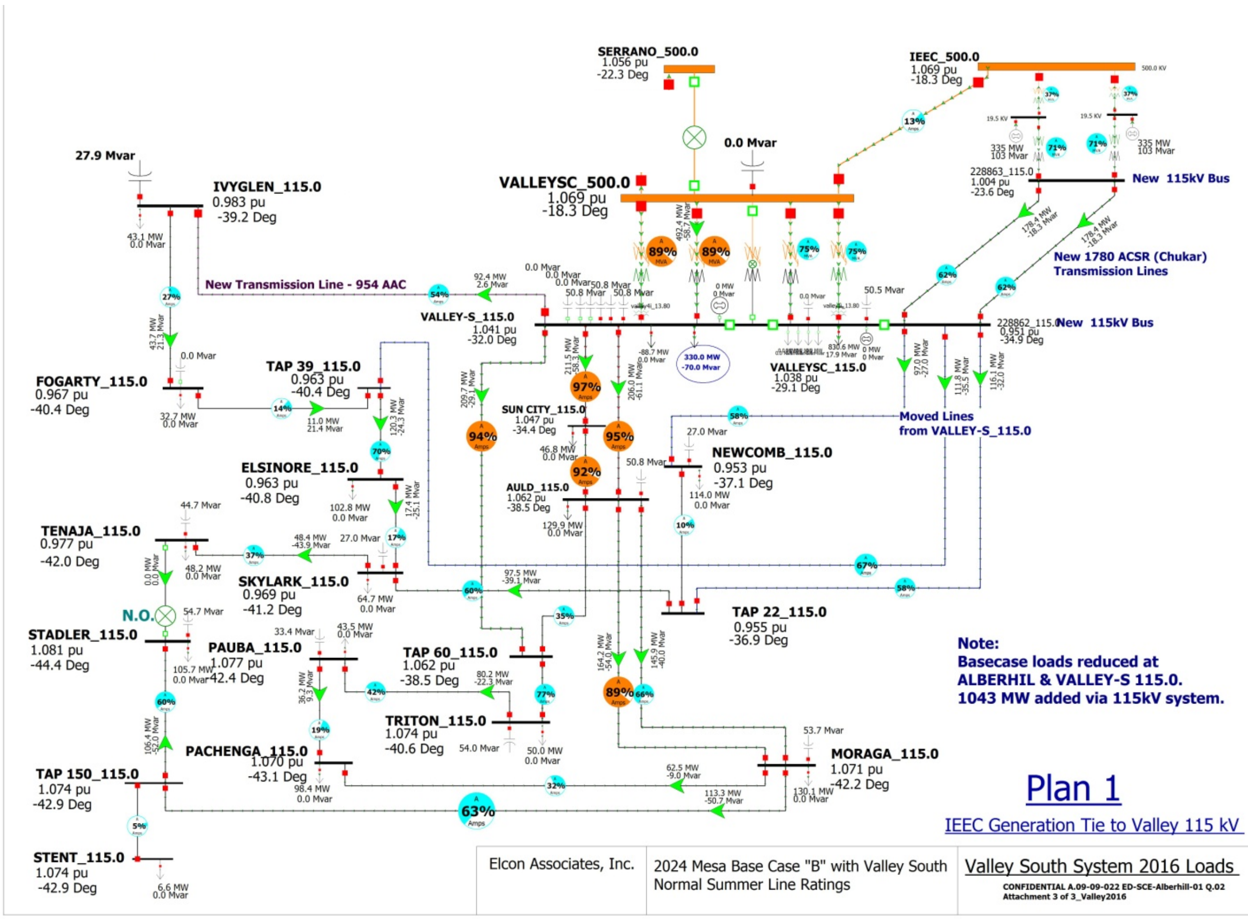
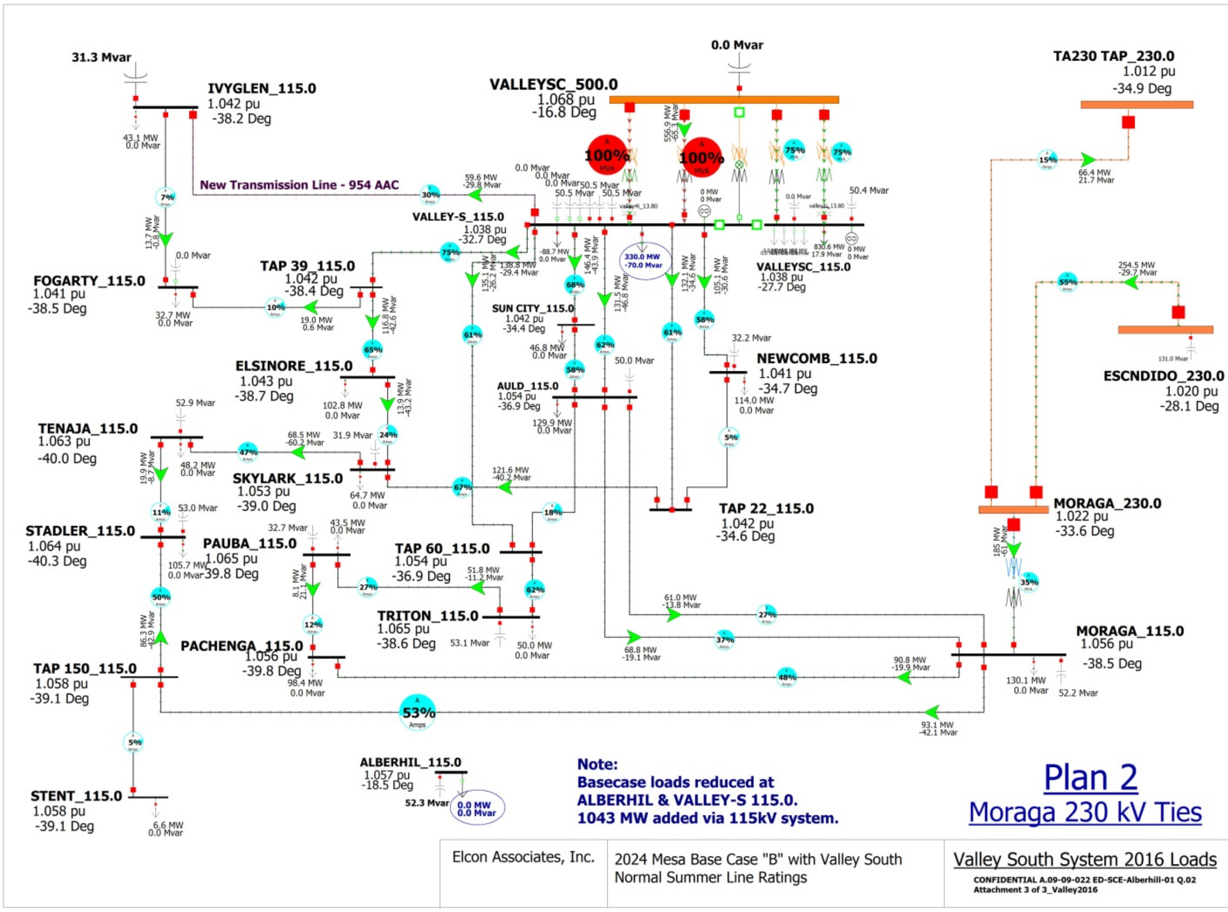


Figure 3: Moraga Tie-In Interconnection



4.0 Conclusion

The CPUC has already determined that the proposed VIG Project is needed as reflected by its previous approval of that project. Therefore, the VIG Project is included in all of the power flow analyses for ASP. SCE has provided data to support its assertion that the ASP Project is needed to increase electrical reliability in the ENA, and the data has been reviewed by the CPUC's independent electrical engineering consultant. The CPUC's alternatives screening analysis for ASP included both substation and non-substation alternatives, but because the non-substation alternatives met none of the project objectives, they were not carried forward for further analysis in the Draft EIR.[8] Given SCE's load projections, which are based on accepted electrical forecasting methodology, the only feasible alternative to the ASP appears to be the construction of a new substation in an alternate location. Expanding the existing Valley Substation, increasing capacity via the IEEC, or connecting the Valley South System to SDG&E's

[8] See DEIR Appendix D, Alternatives Screening Report. Also, see Footnote 1 above.

230-kV system would not relieve future loading concerns and thus would not achieve the purpose of ASP. Further, these alternatives would not meet the project objectives. Any additional alternatives suggested by commenters and not explicitly addressed above have been deemed to present similar issues and would merely delay the construction of a new substation or are well beyond the scope of this project.