# Stakeholder Comments on
# 2012-2013 Transmission Planning Process Stakeholder Meeting
# 11 February 2013

| Submitted by | Company | Date Submitted |
|---|---|---|
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Critical Path Transmission thanks the CAISO for the opportunity to submit these *preliminary* stakeholder comments on the recent Transmission Planning Process Stakeholder meeting and the Draft Transmission Plan.

**Comment 1**

Critical Path Transmission ("Critical Path") has commissioned economic and reliability studies to evaluate the AV Clearview Transmission Project as an alternative to the Coolwater-Lugo LGIA Project (also referred to by the PTO as the South of Kramer Upgrade). These studies were conducted in parallel to those conducted by the CAISO and indicate significantly greater benefits than found by the CAISO. The AV Clearview Transmission Project can:

- provide between $267 and $302 million in total annual benefits to ratepayers – approximately five to seven times the estimated $44 to $54 million in total annual ratepayer benefits from the South of Kramer Upgrade;
- accommodate the interconnection and delivery of approximately three times the new renewable generation of the South of Kramer Upgrade (1,370 MW vs. 435 MW);
- provide significant reliability benefits the South of Kramer Upgrade cannot, including VAR support, relief to potential congestion on Path 26 and relieve longstanding N-2 contingencies in the Kramer area;
- can be in service two years before the South of Kramer Upgrade.

The CAISO has agreed to review the technical studies commissioned by Critical Path. The primary purpose of these preliminary comments is to make the Comparative Economic and Reliability Study Final Report (attached) available for posting in order to provide the stakeholder community the opportunity to review and comment on the alternate Western Mojave transmission solutions.

**Comment 2**

The 2012-2013 ISO Transmission Plan states on Page 1 that "no new major transmission projects are required to be approved by the ISO at this time to support achievement of California's 33% RPS goals given the transmission projects already approved or progressing through the California Public Utilities Commission approval process…" Table 1 (Elements of the 2012-2013 ISO Transmission Plan Supporting Renewable Energy Goals) of the Draft Plan indicates that both the Pisgah-Lugo and the Coolwater-Lugo are counted as part of the transmission elements that are required to meet the 33% RPS needs.

Could the CAISO please provide the following information to stakeholders and also in the Final Transmission Plan:

1. How many megawatts of renewable generation are deliverable by the Pisgah-Lugo line and included in the calculation to meet the state RPS goal?
2. Are all of the megawatts interconnected by the Pisgah-Lugo line deliverable under N-1 conditions (without RAS or SPS)?
3. What is the status of the permitting of the Pisgah-Lugo line?
4. Given the delay in the CPCN application, is the 2017 in service date for Pisgah-Lugo still considered realistic by the CAISO?
5. Given that the developer of the original generation project that triggered the LGIA has gone into bankruptcy, the PPA has expired and the current project sponsor is facing challenging environmental permitting challenges, at what point does the CAISO intend to conclude that the LGIA is no longer viable and terminate the agreement for default?
6. If the Pisgah-Lugo line is deleted from the CAISO assumptions for meeting RPS goals, how many megawatts short of the 33% goal would the Transmission Plan be?

7. How many megawatts of renewable generation are deliverable by the Coolwater-Lugo line and included in the calculation to meet the state RPS goal?
8. Are all of the megawatts interconnected by the Coolwater-Lugo line deliverable under N-1 conditions (without RAS or SPS)?
9. Given the delay in the CPCN application, is the 2018 in-service date for Coolwater-Lugo still considered realistic by the CAISO?

**Comment 3**

Could the CAISO please provide the following information to stakeholders and also in the Final Transmission Plan:

Given the extraordinary deviations of the actual cost of the TRTP and Devers-Colorado River projects from the PTO's original estimates, what is the CAISO's position regarding the use of the PTO's unusually modest Coolwater-Lugo 2010 cost estimate as a basis for comparison with the AV Clearview Transmission Project, whose cost estimate is based on recent input from qualified suppliers? Does the CAISO consider the Coolwater-Lugo cost estimate to be credible? Would the CAISO consider requesting updated Coolwater-Lugo cost information to be used in any comparative analysis?

Comparative Economic and Reliability Study Final Report Attached

# Comparative

# Economic and Reliability Study

## Final Report

## AV Clearview Transmission Project

## and

## Coolwater-Lugo (South of Kramer Upgrade) LGIA Project

## Reliability and Economic Assessment

## February 5, 2013

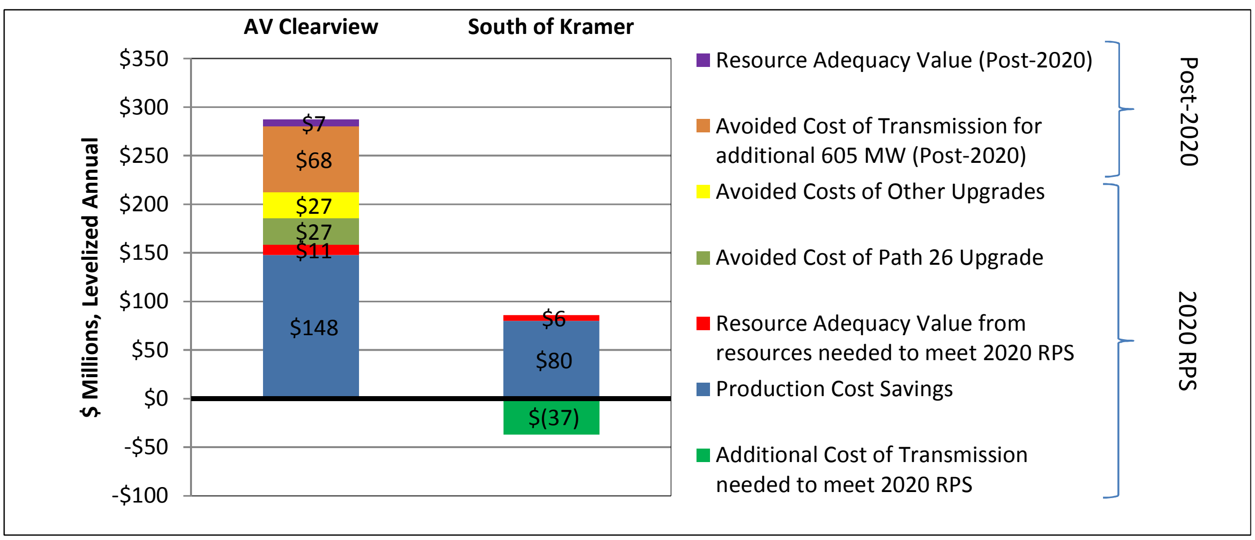
## STUDY OBJECTIVE

ZGlobal was retained to evaluate the economic and reliability benefits of two proposed transmission alternatives in Southern California: The **Antelope Valley Clearview Transmission** ("AV Clearview") **Project** and the SCE Coolwater- Lugo 230 kV transmission project, also called the **South of Kramer** ("SOK") **Upgrade**. Appendices A and B describe the two proposed Projects. This Executive Summary presents the results of the ZGlobal economic and reliability analyses for both the AV Clearview and the SOK projects for comparative purposes.

## EXECUTIVE SUMMARY

The AV Clearview Project is estimated to provide between **$267 and $302 million** in total annual benefits to ratepayers. This is approximately *five to seven times* the estimated $44 to $54 million in total annual ratepayer benefits from the SOK Upgrade. The chart below shows the comparative benefits of the two projects.

**Figure 1: Comparison of Quantified Benefits: AV Clearview vs. South of Kramer Projects**[1]




Quantified Benefits are identified as follows:

- **Production Cost Benefits to Ratepayers:** The levelized annual benefits estimate for the life of the AV Clearview project is $147.6 million, compared to $80 million for SOK. The following table compares the two projects' production cost benefits to ratepayers by

[1] Estimates are levelized annual values. Midpoints or similar appropriate estimates are used in the chart when the underlying analysis may result in a range.

showing the results of the Year 1 calculated savings in the production cost model; the 2017 present value of the flow of savings for the life of the project; and the aforementioned levelized annual benefits for the life of the project.

**Table 1: Ratepayers' Production Cost Benefits Comparison[2]**

| Production Cost Ratepayer Benefits Metric | AV Clearview | South of Kramer |
|---|---|---|
| **Year 1 Production Cost Savings Calculation** | $131.3 million | $82.6 million |
| **2017 Present Value of Benefits for Project Life** | $1.8 billion | $993 million |
| **Levelized Annual Benefits for Project Life** | $147.6 million | $80.0 million |

- **Societal Benefits (excluding Jobs and Taxes):** The levelized annual benefit estimates of Societal Benefits for the AV Clearview and SOK projects, including production cost savings to consumers, plus transmission owner income, offset by the decrease in generator income, are $100.6 million and $27.9 million, respectively. The following table compares the projects' production cost benefits to ratepayers, transmission owners, and generators. It presents the results of the Year 1 calculated savings in the production cost model; the 2017 present value of the flow of savings for the life of the project; and the aforementioned levelized annual benefits for the life of the project.

**Table 2: Societal Production Cost Benefits Comparison**

| Production Cost Societal Benefits Metric | AV Clearview | South of Kramer |
|---|---|---|
| **Year 1 Production Cost Savings** | $89.4 million | $28.9 million |
| **2017 Present Value of Project Benefits** | $1.2 billion | $346.9 million |
| **Levelized Annual Benefits for Project Life** | $100.6 million | $27.9 million |

- The AV Clearview Project can accommodate the interconnection and delivery of approximately **three times the new renewable generation of** SOK under CAISO reliability standards **(1,370 MW vs. 435 MW)**. The following table compares the RPS generation that can be interconnected to the respective projects using a remedial action scheme of 136 MW.

[2] Since the AV Clearview project can come online 2 years sooner, the present value and levelized benefits are larger than those of the SOK Upgrade per dollar of production cost benefit realized in year 1.

**Table 3: Maximum RPS Generation Comparison**

| | AV Clearview | South of Kramer |
|---|---|---|
| **Kramer area generation** | 393 MW | 393 MW |
| **Additional N-1 Capability** | +841 MW | -94 MW |
| **RAS capacity (subject to curtailment)** | +136 MW | +136 MW |
| **Net transmission capability** | 1370 MW | 435 MW |

- In the **2020 RPS Commercial Interest Category of Benefits** ("2020 Benefits", the set of renewable generation projects in the CPUC Commercial Interest Scenario, which are required to meet the 2020 RPS obligation), the AV Clearview Project provides **three times the annual economic benefits to CAISO ratepayers than those of the SOK Upgrade**. This is due to a variety of factors, and in particular to AV Clearview's HVDC component's ability to dynamically shift power flow between existing grid elements to relieve chronic congestion. This allows less-costly hydroelectric and wind generation to reach consumers. The following table presents the resource adequacy value benefits of renewables that can connect to each project, divided between the capacity needed to meet 2020 RPS obligations, and remaining capacity that can meet future RPS obligations.

**Table 4: Renewable Resource Adequacy Benefits Comparison**

| **Benefits Category** | **Metric** | AV Clearview | South of Kramer |
|---|---|---|---|
| **2020 RPS RA Benefit** | Installed Capacity | 765 MW | 435 MW |
| | $ PV project life | $139.6 million | $76.5 million |
| | $ levelized annual | $11.2 million | $6.2 million |
| **Post-2020 RPS RA Benefit** | Installed Capacity | 605 MW | |
| | $ PV project life | $88.8 million | |
| | $ levelized annual | $7.2 million | |
| **Total** | **Installed Capacity** | **1370 MW** | **435 MW** |
| | **$ PV project life** | **$228.3 million** | **$76.5 million** |
| | **$ levelized annual** | **$18.4 million** | **$6.2 million** |

In addition to enabling Tehachapi and Mojave-area renewables to serve load in Southern California, the AV Clearview Project helps to resolve several transmission issues on the California grid.

- In the **2020 RPS Category of Benefits** ("2020 RPS Benefits", benefits of transmission and associated renewable generation projects needed to meet 2020 RPS obligations), the AV Clearview project provides over $100 million in benefits by avoiding costly transmission upgrades. This is because AV Clearview provides congestion relief on Path 26, which the California ISO has cited as a challenging bottleneck; and relief of the overload of Kramer-Lugo.
- The **HVDC component of the AV Clearview Project facilitates a number of valuable operational benefits to the CAISO**, for which the ratepayer benefits are adjudged to be significant but not presently quantified. These benefits include improved real and reactive power control.
- In the **Post-2020 RPS Category of Benefits** ("Post-2020 Benefits", renewable sources enabled by AV Clearview that will be needed to meet RPS obligations after 2020, due to expected load growth), the AV Clearview Project provides an **additional $75 million of economic benefits** annually to the CAISO ratepayers, due to its ability to connect and provide reliable deliverability for over 1,370 MW of new renewable generation. No comparable benefits have been identified from the SOK Upgrade.
- Meanwhile, ZGlobal studies indicate that the SOK Upgrade cannot provide full deliverability of the renewables needed to satisfy 2020 RPS obligations without significant protection and/or remedial action schemes (RAS). To meet 2020 obligations without RAS, as is customary for new transmission, transmission in addition to SOK will be needed, at an estimated levelized annual cost of $37 million.

The following table categorizes the benefits of transmission costs that can be avoided by the construction of the respective projects.

**Table 5: Benefits of Avoided Transmission Costs Comparison**

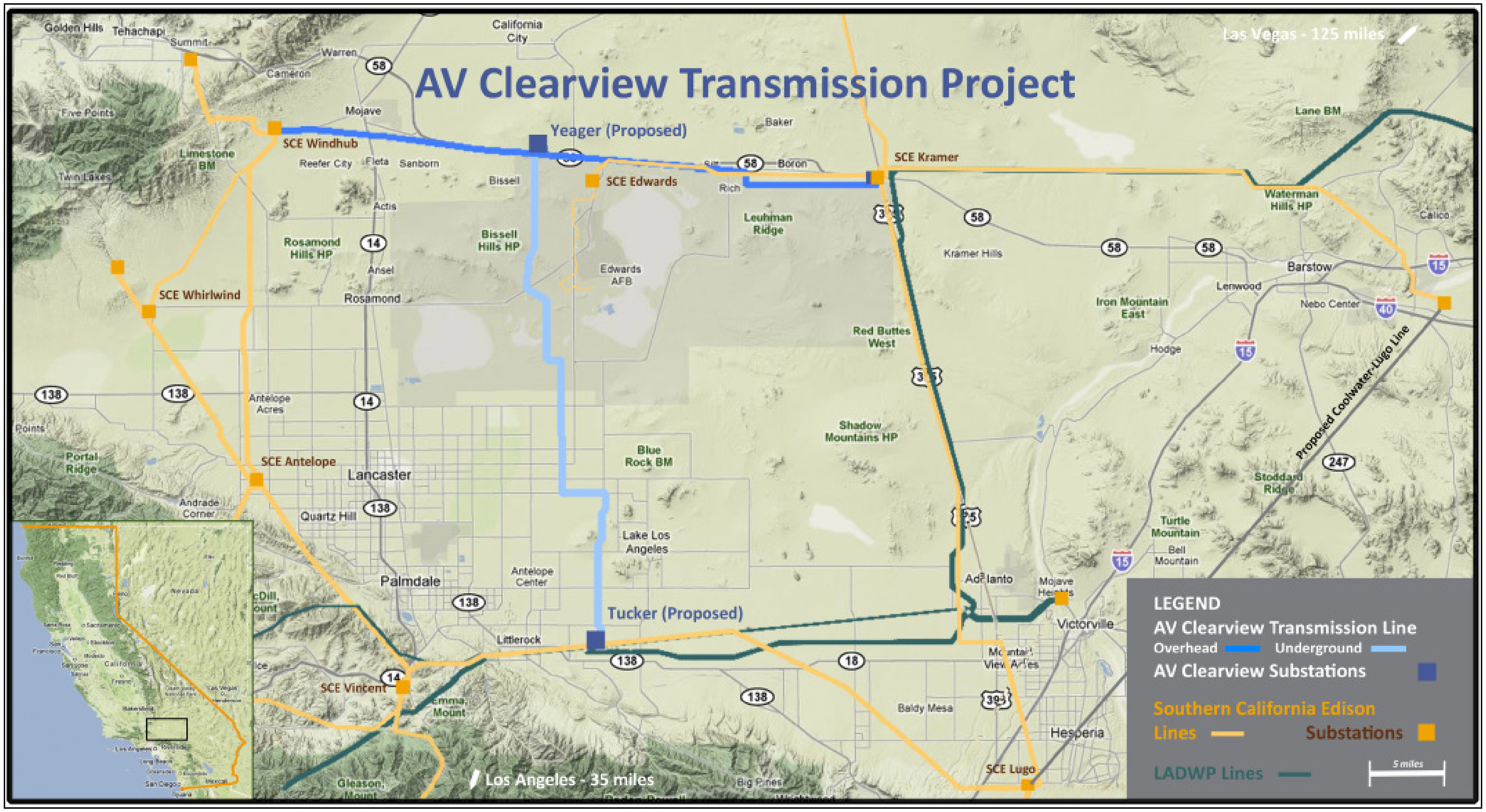
| Transmission Cost Avoided ($ Levelized Annual) | AV Clearview | South of Kramer |
|---|---|---|
| **Path 26 Upgrade** | $27 million | |
| **Other Upgrades** | $14-39 million | |
| **Additional needed to meet 2020 RPS** | | $(37 million) |
| **Total 2020 RPS Benefits** | $41-66 million | $(37 million) |
| **Total Post-2020 Benefits: Avoided Cost of Transmission for Additional 605 MW RA** | $68 million | |
| **Total Benefits of Avoided Transmission Costs** | **$109-134 million** | **$(37 million)** |

Other considerations:

- AV Clearview offers environmental benefits of avoidance of transmission projects, including reduced land disturbance.
- AV Clearview has strong support among local stakeholders.
- AV Clearview can be constructed and in service as early as 2017.

For reference, the following is a map depicting the AV Clearview Project and the SOK Upgrade, along with relevant existing transmission infrastructure.

**Figure 2 : AV Clearview Project Map**



# TABLE OF CONTENTS

## 1.0 Overview of Technical Benefits

The proposed 230-kilovolt AV Clearview Project[3] is to be located in the Antelope Valley region of Kern and Los Angeles counties, with a route chosen in collaboration with local governmental agencies and Edwards Air Force Base. SCE's South of Kramer (SOK) Upgrade is proposed to be located in the western/central San Bernardino County and the Lucerne Valley area of the Mojave Desert.

The AV Clearview Project's optimized location on the California grid gives it several unique technical advantages over the SOK Upgrade, by allowing greater transmission capability from the renewable-rich Tehachapi and Mohave regions, and by providing an alternative path for generation, which reduces the impact of transmission outages. AV Clearview deploys a proven technology solution that will enable CAISO grid operators to re-direct the flow of energy from congested to uncongested transmission corridors as needed, providing increased reliability to ratepayers at lower net cost. These features provide much needed tools to enable low-cost hydroelectric, solar and wind generation to reach consumers in Southern California.

**ZGlobal has concluded that the AV Clearview Project is overwhelmingly superior in both reliability and economic benefits to California ratepayers.**

The AV Clearview Project

1. connects a greater amount of renewable generation;
2. provides considerable renewable energy integration, reliability, and operational benefits;
3. improves the import capability of existing transmission paths (e.g. increases Path 26 transfer capabilities); and
4. increases access and competition to additional generation sources, thereby benefiting consumers with lower energy production costs.

The AV Clearview Project is technically superior to the SOK Upgrade in major respects:

1. **<u>AV Clearview provides superior reliability.</u>** AV Clearview connects two existing transmission bulk systems (the East of Lugo area and the Northern bulk region including the Tehachapi Renewable Transmission Project (TRTP)). Specifically, the AV Clearview Project can provide multiple reliability benefits that the SOK Upgrade does not, such as:

[3] Throughout this document, study results are for the Baseline Version (230 kV Overhead lines and single underground HVDC Circuit) of the AV Clearview Project, with the exception that the 230 kV lines will be constructed to 500 kV standards and initially energized at 230 kV.

a. AV Clearview mitigates existing reliability problems associated with the loss of Kramer – Lugo 230kV lines. The current system is unreliable under an N-2, the loss of two (2) Kramer – Lugo 230kV lines. Under the current system or under the SOK Upgrade cases the loss of these two lines may potentially result in a system collapse. The AV Clearview Project alternative was found to be an effective mitigation for the loss of an N-2 contingency of Kramer-Lugo 230 kV lines during peak and off-peak hours.
b. AV Clearview provides voltage stability through the use of the projects' High Voltage DC (HVDC) reactive capability. The SOK Upgrade does not provide any voltage reactive capability to the grid.
c. AV Clearview interconnects generation without a Special Protection Scheme (SPS) or Remedial Action Scheme (RAS) to meet 2020 RPS obligations. The SOK Upgrade cannot provide firm deliverability to meet 2020 RPS.
d. AV Clearview is reliable under N-0 and N-1 and specifically against the loss of both Kramer – Lugo 230kV lines. The SOK Upgrade provides reduction in flow on the Kramer – Lugo lines under N-0. However, the loss of the SOK will overload Kramer – Lugo lines unless a RAS is implemented.
e. AV Clearview provides relief to potential overloads on Path 26, Kramer area and South of Lugo transmission system. SOK has the potential to trigger upgrades on South of Lugo and does not provide any relief for Path 26.

2. **<u>AV Clearview provides renewable integration benefits.</u>** The AV Clearview Project integrates the Kramer area, one of the best locations in California for solar power development, and the Tehachapi area, a prime area for wind power development, into a transmission system that facilitates optimum use of these resources, while providing real mitigation to existing grid concerns on Path 26 and Kramer area transmission systems.
3. **<u>AV Clearview increases Path 26 energy transfer capability.</u>** The AV Clearview Project increases the energy transfer capability of Path 26:
   a. The combination of the AV Clearview Project's 230kV lines and the HVDC capability results in increased Path 26 transfer capability in both the North to South and South to North scenarios by 500 to 750 MW, depending on the operating conditions. This increase in existing transmission capabilities enables delivery of low cost hydroelectric, solar and wind generation to Southern California.
   b. The AV Clearview Project mitigates congestion of Path 26, eliminating the need for an upgrade to Path 26. This is achieved through the direct interconnection of AV Clearview's two 230kV lines (Windhub – Yeager –

Kramer 230kV system). Furthermore, Path 26 loading (or off-loading) can be regulated through the Windhub-Yeager HVDC interconnection.

c. The SOK Upgrade does not provide any balance to the resources between TRTP and Kramer and has no impact on Path 26.

4. **AV Clearview provides deliverability to significantly more renewable generation.** The AV Clearview Project under all its variants meets or exceeds the ability to deliver the 765 MW as projected in the CPUC Commercial Interest Generation Scenario for the Kramer area.

5. **AV Clearview can interconnect three times (3x) more generation than the SOK Upgrade.** The AV Clearview Project has the ability to interconnect three times (3x) more generation than the SOK Upgrade at no incremental cost, which is an important and prudent planning criterion. The AV Clearview Project provides California with cost-efficient renewable interconnection, maximizing existing infrastructure and increasing utilization of existing assets. The AV Clearview Project can connect up to 1370 MW of new generation, compared to only 435 MW for the SOK Upgrade, as detailed in Appendix D.

**Given the 33% RPS obligation, we expect that load growth will result in full utilization of the higher capacity provided by AV Clearview by 2023.**

Overall, The AV Clearview Project provides substantially more benefit to ratepayers than the SOK Upgrade. The AV Clearview Project has multiple categories of benefits including interconnecting more renewable generation, increasing the operational control and reliability of the grid and providing a solution to existing reliability issues and Path 26 congestion as described in this report. Although neither policy-driven nor LGIA-driven projects require a net economic benefit for inclusion in the CAISO Transmission Plan, the selection of a plan with superior economic, reliability and operational benefits, earlier in-service date and lower environmental impact should be in the best interests of the ratepayers, renewable developers and the CAISO.

## 2.0 Overview of Economic Benefits

ZGlobal allocated quantified benefits from each project into two separate categories: a 2020 Renewable Portfolio Standard (RPS) Commercial Interest Benefits Category, and a Post-2020 RPS Benefits Category.

### 2.1 Benefits Category I: 2020 RPS Commercial Interest Benefits

The 2020 RPS Commercial Interest Category of Benefits ("2020 Benefits") uses the following critical assumptions and associated generator interconnection capability:

**Table 6: Assumed Commercial Interest Required to meet 2020 RPS Obligations**[4]

| Assumption | AV Clearview | South of Kramer |
|---|---|---|
| **Date of Service** | 2017 | 2019 |
| **Baseline PUC Generation Portfolio for Kramer and Lucerne Renewable Zones** *(2012/2013 Commercial Interest Portfolio)* | 765 MW (Kramer)<br>106 MW (Lucerne) | 765 MW (Kramer)<br>106 MW (Lucerne) |
| **Baseline Project Configuration** | See Appendix A | See Appendix B |

Table 8 on page 14 summarizes the 2020 Benefits for the life of the project, on an annual levelized basis.

### 2.2 Benefits Category II: Post-2020 RPS

CAISO assumptions about load growth, combined with California's statutory commitment to 33% renewable generation, indicate that additional generation and transmission will be needed in this region. The incremental benefits of interconnecting additional renewable generation under both Projects as necessitated by load growth to meet RPS obligations is quantified in the Post-2020 RPS Category of Benefits ("Post-2020 Benefits").

The AV Clearview Project is capable of interconnecting 1,370 MW of generation, representing an additional 605 MW of capacity for the interconnection of renewable generation over the 765 MW stated in the CPUC Baseline (Commercial Interest) portfolio. Benefits from the 765 MW are allocated to the 2020 Benefits Category. The additional 605 MW of renewable generation can

[4] We use the relevant year's CEC load forecast, the same renewable mix throughout the rest of CAISO grid, as well as the same approved transmission upgrades, gas forecast and hydro and system conditions in evaluating both projects.

interconnect at no incremental cost, and the corresponding benefits are categorized as Post-2020 Benefits.

The SOK Upgrade can only interconnect 435 MW under the same applicable reliability standards. This represents a deficit of 327 MW below the CPUC 765 MW portfolio assumptions for the Kramer region. There is an additional 106 MW of portfolio generation interconnecting at the Jasper substation as part of the SOK Upgrade. When this is added to the Kramer region (765 MW scenario), the SOK Upgrade is deficient by a total of 433 MW. This deficiency suggests no incremental benefit of the SOK Upgrade in the Post-2020 Benefits category.

Table 9 summarizes the Post-2020 Benefits for the life of each project, on an annual levelized basis.

## 2.3 Summary of Interconnection Ability

ZGlobal has performed power flow analysis and determined the interconnection capability of each project. The results of this analysis are presented as follows:

**Table 7: Comparison of Interconnection Potential**

| Interconnect Ability Finding | AV Clearview | South of Kramer |
|---|---|---|
| **Total Possible New Generation Interconnected, based on CAISO reliability standards** | 1,370 MW | 435 MW[5] |

## 2.4 Ratepayer Benefits Summary

The following tables summarize the estimated annual benefits in each category.

[5] Based on applicable reliability criteria, the SOK upgrade can only interconnect 435 MW of new generation (beyond existing interconnected generation). We note that this is inconsistent with the PUC Commercial Interest portfolio indicating 765 MW in this region.

**Table 8: Levelized Annual Benefit Comparison – 2020 RPS Category**

| Benefit Categories | Benefit | AV Clearview Project ($2017 million/year) | SOK Upgrade with RAS ($2017 million/year) | Section |
|---|---|---|---|---|
| **(1)** | Energy Production Cost Savings | $140 - $150 [6] | $75 - 85[7] | 4.1 |
| **(2)** | Decrease in the Cost of Capacity – Resource Adequacy | $11[8] | $6[9] | 4.2 |
| **(3)** | Avoid Upgrade to Path 26 | $27[10] | 0[11] | 4.3 |
| **(4)** | Avoid Other Needed Upgrades | $14 – $39 | 0 | 4.4 |
| **(5)** | Enhance System Operational Flexibility | Many flexibilities | Limited flexibilities | 4.4 |
| **(6)** | Avoid Incremental Transmission Developments to meet the PUC Portfolio in Kramer area | N/A | -$37[12] | 4.5 |
| Total Quantifiable Year 2020 Benefits | | **$192 - $227** | **$44 - $54** | |

6 Based on 765 MW of new renewable at the Kramer zone connecting to the AV Clearview Project.

7 Based on a maximum amount of Renewable that the SOK Upgrade is able to interconnect which is 435 MW. We also discounted SOK by two years to ensure that both projects were evaluated in term of $2017.

8 Based on 765 MW of new generation connecting to the AV Clearview project

9 Based on 435 MW of new generation connecting to the SOK project

10 AV Clearview reduces the flow on the congested Path 26 and is able to save ratepayers the cost of upgrading the path. CAISO lowest cost estimate for upgrading Path 26 is $180 million

11 SOK does not help mitigate any Path 26 flow. If SOK Upgrade is selected, Path 26 upgrade is still needed.

12 CPUC Baseline scenario is 765 MW. SOK is only able to interconnect 435 MW. The transmission cost of additional 327 MW is $37 million/yr.

**Table 9: Levelized Annual Benefit Comparison – Post-2020 Category**

| Benefit Categories | Benefit | AV Clearview Project ($2017 million/year) | SOK Upgrade with RAS ($2017 million/year) | Section |
|---|---|---|---|---|
| **(6)** | Avoid Incremental Transmission Developments for 605 MW of Renewables beyond 2020 | $68 | 0 | 5.1 |
| **(7)** | Value of Resource Adequacy Capacity Needed after 2020 | 7 | 0 | 5.2 |
| **(8)** | Environmental and Societal Benefits (incl. Jobs and Taxes)[13] | Acceleration of economic development benefits has increased value of 16% per dollar spent | | 6.0 |
| Total Quantifiable Post-2020 Benefits | | **$75** | 0 | |

[13] Provide early (2-3 years) start and early job creation. This is a benefit to project employees, communities, etc., many but not all of whom are SCE ratepayers.

# 3.0 Detailed Description of Transmission and Reliability Benefits

The Path 26 transmission corridor is critical to the delivery of inexpensive hydroelectric power from Northern California and the Pacific Northwest to electricity consumers in Southern California. In addition, Path 26 provides for the reliable delivery of solar and wind generation from the Tehachapi region.

Path 26 consists of three (3) 500 kV lines south of the Midway substation near Bakersfield connecting PG&E and SCE Service territories. Path 26 is also one of the most troublesome bottlenecks in the California grid.[14]

The South of Lugo ("SOL") path is a primary Southern California delivery corridor for resources from Nevada and the rich solar resource that extends from just east of the Tehachapi Mountains through the Antelope Valley and from the Kramer CREZ.

These two major transmission corridors – Path 26/TRTP and Kramer/SOL – both connect to the SCE system via the Vincent-Lugo corridor, but are otherwise isolated from one another. A consequence of this separation between solar fields east of the Tehachapi region and the western wind region of the Tehachapi/Northern California hydroelectric is that Path 26 becomes a bottleneck whenever high wind production is coincident with high hydroelectric generation. According to the CAISO, the grid will experience congestion along this path for over 1,500 hours per year starting in 2017 (about 18% of the total hours per year). Our analysis shows greater than 3,000 hours per year of congestion on Path 26.

The AV Clearview Project's ability to relieve this congestion with a direct electric connection between these two sections of the grid is a significant driver of many of the benefits identified in this Executive Summary. Through a direct electrical interconnection, the AV Clearview Project integrates two important regions (west and east of the Tehachapi). In addition, the AV Clearview Project's HVDC technology can be used to selectively increase transfer of energy from Path 26 to South of Lugo and vice versa, preventing the curtailments of low cost hydroelectric, solar and wind generation. <u>This is one of the major advantages of the AV Clearview Transmission Project.</u>

[14] See section A4

## 4.0 2020 RPS Economic Benefit to California Ratepayers

ZGlobal adopted the following guiding principles in evaluating the economic benefits of the Proposed AV Clearview Project and the SOK Upgrade:

- A standardized production cost methodology is used to measure the economic benefits of proposed transmission projects. The perspective of CAISO ratepayers is of primary importance, although we have noted other values in reviewing benefit results from other perspectives as well.
- ZGlobal used the CAISO framework for the computation of potential energy benefits. ZGlobal's assessment of energy benefits uses established, credible, and commercially available production cost modeling tools.
- In addition to energy benefits, other economic effects of the transmission project are considered, including economic effects that are difficult to quantify or may not be quantifiable.
- Economic evaluations consider how uncertainty about future systems and market conditions affect the likelihood that a transmission project's forecasted benefits will be realized.
- Economic evaluations use baseline resource plans and assumptions about the system and are believed to be consistent with resource plans and system assumptions used in CAISO transmission planning, procurement or other recent Commission proceedings, updated as appropriate.
- Economic evaluations consider feasible resource alternatives to the proposed transmission project such as the SOK Upgrade.

*The following Sections correspond to the 2020 RPS Benefit Category summarized in Table 8.*

### 4.1 Energy Production Cost Savings

ZGlobal uses the established CAISO Transmission Economic Assessment Methodology (TEAM). The TEAM approach is recognized as progressive and path breaking, and has been adopted by the CPUC as the standard approach by which to evaluate the economic benefit of transmission projects.[15] The TEAM methodology has been modified to be applicable to California's current nodal pricing model. The TEAM approach:

[15] California Public Utilities Commission, Decision 06-11-018, "Opinion on Methodology for Economic Assessment of Transmission Projects," November 9, 2006, http://docs.cpuc.ca.gov/published/Final_decision/61783.htm.

- Uses a production cost model to estimate benefits for consumers, producers, and transmission owners separately;
- Constructs a generation supply curve and dispatches units economically to match generation with load in each hour of the study period.

CAISO has used the TEAM Methodology in each of their economic analyses of new proposed transmission projects over the last decade. The CPUC has recognized this as the standard methodology to be used in the economic evaluation of transmission projects.[16]

The consumers' levelized annual benefit attributed to the decrease in energy production costs facilitated by the AV Clearview Project, under a specific set of assumptions, was calculated to be $147.6 million/year (in 2017 dollars). In contrast, the SOK Upgrade levelized annual consumer benefit associated with reducing energy cost to ratepayers was estimated to be $80 million/year (in 2017 dollars)[17].

Appendix C details the economic analysis assumptions and detailed results for both the AV Clearview Project and SOK Upgrade used in these studies.

## 4.2 Decrease in the Cost of Capacity – Resource Adequacy

Renewable generation interconnected to either proposed project may count toward the utilities' Resource Adequacy obligation. A conservative value of the system Resource Adequacy capacity value of $3/kW-month was used. The levelized value of the capacity associated with connecting 765 MW of solar to the AV Clearview Project is estimated to be approximately $11.2 million/year.[18] The same calculation applied to the 435 MW of generation that can interconnect to the SOK Upgrade returns a value of approximately $6.2 million/year.

Appendix E details the methodology used.

## 4.3 Avoid Upgrade to Path 26

The CAISO has expressed concern with the increased congestion on the main interconnection between Northern/Central California and Southern California through Path 26. Path 26 is a transmission highway that enables the transfer of low-cost hydroelectric power from Northern

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[16] CPUC Decision 06-11-018, November 9, 2006.

[17] The proposed SOK Upgrade is expected to be on line in 2019. To compare the two projects in $2017, we adjusted the SOK Upgrade benefit to account for the two year lag period.

[18] We used 3$/kW-month for 2012, adjusted by a net 0% escalation after inflation over the life of the project and calculate the levelized value.

California and wind and Solar power from the Tehachapi region into southern California. On December 11, 2012 at the CAISO stakeholder meeting, CAISO stated that:

> *"Path 26 operational limit will often be significantly lower than the 4,000 MW paths rating when the new Whirlwind 500 kV substation is looped into the Midway-Vincent line #3. The most limiting conditions are the L-1 situations on Path 26 lines. The most limiting elements are the series capacitors on Midway-Vincent #1 and #2 lines. Path 26 congestion has been top-ranked in the ISO studies for four consecutive years. However, studies have not found significant economic benefit to relieve this congestion. The reason is that north and south LMP changes result in canceled-dollar benefits. Path 26 congestion is not only forecasted, but also an operations reality."*

Furthermore, CAISO stated,

> *"Path 26 is perhaps the most important link in the California transmission system. Any disruptions on Path 26 jeopardize system reliability and market integrity. It has been a challenge to find economic justification to relieve this congestion bottleneck. In this situation, [we] shall also explore other justifications, such as policy and reliability needs."*[19]

Through the technological flexibility of the AV Clearview Project, a significant amount of inexpensive energy that otherwise will be curtailed can flow to Southern California ratepayers using the AV Clearview Project's HVDC technology, which is described in Appendix E.

CAISO notes that congestion on Path 26 is forecasted to be over 1,500 hours in 2017.[20] Our analyses are consistent with the CAISO findings. Our analyses also show significant energy flows shifting from Path 26 to AV Clearview. The AV Clearview 230 kV lines at Windhub, along with the ability to use the HVDC, result in significantly reduced Path 26 congestion. Specifically, congestion occurred in 548 hours in the AV Clearview case in the modeled year, compared to 879 hours in the base case, a decrease in congestion of 313 hours.

The reduced flow on Path 26 decreases the prevalence of curtailment of low-cost generation due to Path 26 congestion. The AV Clearview scenario showed reduced flow on Path 26 in 3,800 of 4,515 hours in 2017 during which flow was in the north-to-south direction in the base case,

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[19] 2012/2013 Transmission Planning Process Stakeholder Meeting
December 11-12, 2012, http://www.caiso.com/planning/Pages/TransmissionPlanning/2012-2013TransmissionPlanningProcess.aspx
[20] , http://www.caiso.com/planning/Pages/TransmissionPlanning/2012-2013TransmissionPlanningProcess.aspx

for a total decrease of 479,536 MWH for the modeled year. In addition, when the HVDC is utilized, we observed that the AV Clearview can resolve congestion on Path 26. This highlights an essential feature of the AV Clearview Project, and in particular, the HVDC technology: the ability to relieve congestion on one of the key bottlenecks on the California transmission grid.

The decrease is attributed to a shift in power flow from Path 26 to the east of the Tehachapi region avoiding Path 26 through the AV Clearview project. This reduction is achieved without fully using the HVDC's phase angle adjustment capability; additional reduction in Path 26 can be achieved through the use of the HVDC power orders.

CAISO proposed three alternatives to upgrade Path 26, with capital costs ranging from $180 million to over $1 billion.[21] AV Clearview's ability to shift flows from Path 26 would displace the needed upgrade for Path 26. Avoidance of the conservative estimate by the CAISO of $180 million results in a cost savings to ratepayers of $27 million/year.[22]

We encourage the CAISO to model the AV Clearview Project's HVDC operating capability in a manner where HVDC power orders can shift the loading on Path 26 to the AV Clearview path (See Appendix D). The unique feature of HVDC is the ability for the operator to "dial in" the power order; i.e. the amount of MW to be shifted from one path to another.

## 4.4 Avoid Other Needed Upgrades; Enhance System Operational Flexibility

### 4.4.1 Avoid the Upgrade for Kramer-Lugo

The Kramer path consists of two 230 kV lines from Kramer to Lugo. CAISO identified two critical issues with the existing Kramer – Lugo 230 kV lines:

- During certain hours of the year and under N-0, the flow on the Kramer – Lugo 230 kV line and the 230/115 kV transformer can exceed 115% of their rating.
- A double line outage on the Kramer-Lugo 230 kV line #1 and #2 (N-2 conditions) causes severe reliability problems (power flow divergence and possible system collapse).

ZGlobal's analyses conclude that the AV Clearview Project reduces the flow on the Kramer path under N-0, N-1 and N-2 conditions and protects the grid against an N-2 on the Kramer – Lugo 230 kV lines.

[21] , http://www.caiso.com/planning/Pages/TransmissionPlanning/2012-2013TransmissionPlanningProcess.aspx
[22] We used a factor of 15% to calculate the annual revenue requirement or cost to ratepayers per year.

The SOK Upgrade reduces the flow on these two lines only under an N-0 condition, but *not* under N-1 or N-2 conditions.

At some point, CAISO will have to upgrade the lines from Kramer to Lugo with a cost that is expected to range between $75 and $250 million after SOK is completed.[23] This would not be necessary with the AV Clearview Project. Our analysis indicates that, under normal conditions through the combination of the new AV Kramer – Yeager 230 kV lines and the use of the HVDC phase shifting function, at least 220 MW of flows can be shifted from the Kramer – Lugo lines to the AV Clearview Project's Kramer – Yeager 230 kV lines.

Based on the projected capital cost of $75 million to $250 million, the levelized annual cost to ratepayers of upgrading the Kramer – Lugo line, that otherwise would not be needed under the AV Clearview, is in the range of $11 million to 39 million/yr.

Appendix D shows details of the reliability analysis.

#### 4.4.2 Avoid Curtailments on TRTP under Normal and Outage Conditions

Currently, outages or line derates on the Windhub 230/500 kV transformer, the Windhub-Whirlwind 500 kV line or Windhub-Antelope 500 kV line, or Path 26, require the curtailment of renewable economic generation sources in the Windhub area.

#### 4.4.3 Voltage and Frequency Support

The use of proven HVDC technology provides the Tehachapi and the Kramer regions with much needed reactive support which will improve the reliability and the stability of the grid. For example, the CAISO identified that upon the loss of the Inyokern-Kramer 115 kV line, voltages at the Inyokern, Coso, Downs and Randsburg 115 kV substations dipped below reliability levels.[24]

**Our analysis shows that reactive support from AV Clearview HVDC of 300 - 500 MVAR at the proposed Yeager station will mitigate the voltage dips at all of these 115 kV substations.**

The SOK Upgrade does not provide any mitigation to voltage dips on the 115kV system.

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[23] Based on initial estimate to either re-conductor the two Kramer / Lugo lines (if possible) at a cost of $75million or build a third line at a cost of $250 million.

[24] 2012-2013 Transmission Planning Process Stakeholder Meeting, http://www.caiso.com/Documents/Presentation2012-2013TransmissionPlanningProcessStakeholderMeetingDec11-12_2012.pdf, Slide 12, retrieved 2/4/2013.

ZGlobal conservatively estimates the cost to upgrade the network and avoid these voltage problems specifically at **$3 million per year.** The AV Clearview HVDC allows ratepayers to avoid this upgrade cost.

## 4.5 Avoid Incremental Transmission Developments to Meet the 2020 RPS Commercial Interest Portfolio in the Kramer Area

The AV Clearview Project can connect all 765 MW of renewable generation assumed under the CPUC 2012/2013 Commercial Interest Portfolio while the SCE SOK Upgrade can only connect 435 MW out of the 765 MW. The incremental cost of transmission that can interconnect the shortfall of 327 MW can be expensive and is significant. In other words, if the SOK Upgrade is selected, additional transmission costs (needed reliability and deliverability upgrades) will be incurred in order to interconnect the additional 327 MW of renewable generation. Using the average per MW transmission cost for the Devers – Colorado River (DCR) and Tehachapi (TRTP) project of $747,000, transmission for an additional 327 MW will have a capital cost of $244 million or an annual levelized cost of $37 million/year. This is necessary to meet 2020 RPS in addition to the SOK Upgrade cost. If the AV Clearview Project is selected, the annual cost of $37 million/year will not be incurred by ratepayers since AV Clearview can interconnect the 327 MW at no additional cost.

## 5.0 Post-2020 Benefits to California Ratepayers

*The following sections correspond to the Post-2020 Benefit Category summarized earlier in Table 2.*

Consistent with the PUC portfolio, the baseline estimate of the economic benefit provided by the AV Clearview Project is based on 765 MW of generation interconnection. The AV Clearview Project is able to connect and provide reliable deliverability for over 1,370 MW of new renewable generation, or 605 MW above the baseline estimate.

### 5.1 Avoid Incremental Transmission Developments for 605 MW of Renewables Beyond 2020

The AV Clearview Project is capable of connecting up to 1,370 MW of new generation under CAISO reliability standards. As stated above, AV Clearview can connect all 765 MW of renewable generation under the CPUC Commercial Interest Portfolio while the SOK Upgrade can only connect 435 MW out of the 765 MW. Any future transmission needs above the current PUC portfolios will require investment in new transmission or upgrades to existing transmission.

**Based on our conservative estimate of load growth, the full 1,370 MW of AV Clearview's renewable transmission capacity will be needed to meet California's 33% RPS obligation by 2023.**

If the SOK Upgrade were selected, the requirement for new transmission to accommodate generation beyond the SOK rating of 435 MW must be considered as an additional cost to ratepayers. If the AV Clearview Project is selected, any generation above 765 MW and up to 1,370 MW (i.e. an additional 605 MW) can utilize AV Clearview transmission without incurring additional capital expenditure. The geographic area where AV Clearview is located, stretching from Windhub in the Tehachapi to Kramer Junction, with its exceptional solar resources, abundant depleted agriculture land, and experienced permitting authorities, is prime land targeted by developers as the future site of lower cost solar (including thermal) generation. It is more than reasonable to assume that at least 605 MW of new generation will seek to interconnect via transmission capacity made available by the AV Clearview Project.

Using the average $747,000 per MW transmission cost for the DCR and TRTP projects, the 605 MW of additional transmission interconnection capability will have a capital cost of $454 million or an estimated annual levelized cost of $68 million/year. **If the AV Clearview is selected, this avoided annual cost of $68 million/year would count as potential ratepayer savings.**

## 5.2 Value of Resource Adequacy Capacity Needed after 2020

Renewable generation interconnected to either project may count toward the utility Resource Adequacy obligation. We used a conservative system Resource Adequacy capacity value of $3/kW-month. **The present value of the capacity associated with connecting the incremental 605 MW of solar to the AV Clearview is calculated to be $7.2 million/year.**[25] The SOK Upgrade is not able to connect any additional generation.

Assuming 1.5% annual load growth beyond 2020, and half of the 33% RPS obligation is met with solar in the Kramer area in the early 2020s, we estimate that this incremental capacity will be needed and fully utilized by 2023.

The following table compares levelized annual Resource Adequacy values for the two projects. The CAISO 2012 Transmission Plan requires 764 MW of net qualifying capacity from the region.

**Table 10 : Resource Adequacy Value**

| Benefit Category | | AV Clearview | South of Kramer |
|---|---|---|---|
| **2020 RPS RA Benefit** | Installed Capacity | 765 MW | 435 MW |
| | $ levelized annual | $11.2 million | $6.2 million |
| **Post-2020 RPS RA Benefit** | Installed Capacity | 605 MW | |
| | $ levelized annual | $7.2 million | |
| **Total** | **Installed Capacity** | **1370 MW** | **435 MW** |
| | **$ levelized annual** | **$18.4 million** | **$6.2 million** |

A discussion of the methodology for valuing RA capacity is presented in Appendix E.

[25] 3$/kW-mo was used for 2012, adjusted by a net 1% escalation after inflation over the life of the project and calculate the levelized value

# 6.0 Environmental and Societal Benefits

## 6.1 Environmental Benefits

Although this document does not purport to provide an in-depth environmental analysis, initial review of both alternative projects suggests that the AV Clearview Project avoids or mitigates the impact on the critical and sensitive environmental regions of the Southern California desert. AV Clearview affords a number of deliberate environmental advantages that policy-driven projects should be designed to provide:

- **Avoided Environmental Costs:** Just as there are "avoided economic costs" by avoiding the need to build future transmission projects, the same is true of "avoided environmental costs." That is, if a policy-driven project can meet the contractual requirements of interconnected generation, while also providing sufficient interconnection capabilities for future generation and avoiding the need for future transmission lines, there is a significant avoided environmental impact.
- **Low Disturbance:** About half of the AV Clearview Project will be underground HVDC along existing county road rights of way. An HVDC circuit can be direct-buried in a two foot wide trench. Not only is the required right of way much less than an overhead line, but habitat is only temporarily disturbed. Moreover, an underground configuration means no impact on visual resources, no avian hazards, less opportunity for raven predation, and no chance of initiating a wildfire or being destroyed by a wildfire.
- **Stakeholder Support:** The Petition for Declaratory Order filed with FERC for the SOK Upgrade states that the greater Mojave Desert region is "an area that is becoming increasingly difficult to procure right-of-way for high voltage transmission lines due to competing land interests and other environmental concerns"[26]. Meanwhile, the developers of the AV Clearview Project have worked closely with local stakeholders for the past four years, addressing their concerns and incorporating their suggestions into the design and routing of the Project. This is a key factor in the strong local and regional support for AV Clearview.

- Because the AV Clearview Project mitigates congestion along Path 26 and eliminates the need to upgrade Path 26, it also avoids the significant environmental impacts associated with any expansion of the Path 26 transmission lines that could be needed to serve additional renewable generation.

[26] Southern California Edison Petition for Declaratory Order for Incentive Rate Treatment, Exhibit B – Holdsworth Affidavit, Page 7 of 26, Paragraph 15.

The Path 26 lines cross the San Joaquin Valley; the Tehachapi Mountains and other central Transverse Ranges; and the Antelope Valley section of the Mojave Desert. Upgrading Path 26 through the Tehachapi Mountains and other rugged terrain would pose several environmental challenges. Much of the area is within the Angeles National Forest under the jurisdiction of the US Forest Service, a constraint that is not present for the AV Clearview project. In addition, an upgrade could impose significant long term impacts on special status avian species in this habitat, including the California condor, golden eagle, and other raptors. Whereas the underground part of the AV Clearview project would only temporarily disturb habitat for these species, biological resource agencies will likely consider Path 26 transmission upgrades through protected mountainous habitat as permanent impacts. In addition, resource agencies are increasingly concerned about the cumulative impacts on avian species of wind generation in the area crossed by Path 26. Thus, eliminating the need to upgrade Path 26 the AV Clearview project avoids unnecessary impacts to avian species and offers a clear environmental benefit.

## 6.2 Social Benefits

Electric system investments create jobs and spur economic activity. This spending will have a major positive impact on California's economy.

Since the AV Clearview Project can be constructed two years before the SOK Upgrade, the discounted present value of its economic stimulative benefits of spending will be approximately 16 percent greater per dollar spent.

Using SCE's approach (see Appendix G for methodology), AV Clearview's $670 million in capital expenditure over 3 years, plus $50 million in SCE upgrades, will translate to approximately 1,205 jobs and $69 million in state and local taxes. Accounting for the economic multiplier effect of spending by those employed on the project, etc. the total economic value of this project is likely to be on the order of $1.2 billion.

Although we have not attempted to make a detail environmental analysis, the developers of AV Clearview have worked closely for four years with the local agencies – Kern County, Edwards Air Force Base and Los Angeles County - that will be necessary to obtain crucial rights of way and/or permitting. Strong support for the project has been expressed by the elected officials of a number of affected jurisdictions, including:

- Kern County Board of Supervisors

- State Senators and Assemblymen of the region
- The City of Lancaster

Neither ZGlobal nor the Project Sponsor of AV Clearview is aware of any corresponding support for the SOK Upgrade from local stakeholders.

# 7.0 Cost Assumptions

The CAISO suggested in a December 2012 Stakeholder Meeting that "constructed cost" will be one of the primary metrics by which they will judge the relative merits of the two alternative transmission projects in the Western Mojave.

Without a doubt, project cost is an important consideration in evaluating project *net* benefits. Project costs ultimately paid by the ratepayer are determined not just by the ex-ante estimated construction costs, but also by financing structure and incentives, O&M costs, and cost overruns.

Therefore, on the basis of updated construction cost estimates from the AV Clearview sponsors and the recent challenges Southern California Edison has had in accurately estimating costs during development, ZGlobal analysis indicates that the two projects' costs are in close proximity, as indicated in Section 7.2. Therefore, this report focuses on the benefits comparison between the alternative projects.

## 7.1 AV Clearview Project Estimated Costs

AV Clearview's sponsors have continued to work with constructors, HVDC suppliers, financiers, right-of-way specialists and environmental consultants to develop accurate estimates of the constructed cost of the AV Clearview Project. The present construction estimate is **$670 million**, including contingency. In addition, state regulators have expressed the desire to remove existing financial incentives for cost overruns, which the Project Sponsor is willing to address.

## 7.2 SOK Upgrade Estimated Costs

Based on information provided by the CAISO, the SOK Upgrade is estimated to cost **$480 million.**[27] However, the two most recent examples of Edison transmission upgrades, the Tehachapi Renewables Transmission Project (TRTP) and the Devers-Colorado River (DCR) line are examples illustrating the difficulty SCE has had in estimating costs.

[27] http://www.ferc.gov/EventCalendar/Files/20110311122756-EL11-10-000.pdf. Recent CAISO estimates presented on December 11, 2012 stakeholder meeting estimate the SOK Upgrade cost at about $480 million, with a reduced scope of work at the Lugo Substation. No basis for the cost estimate is cited in either reference.

**Table 11 : TRTP Cost Revisions (prior to Chino Hills undergrounding)[28]**

| Original FERC Filing | Original Project Cost | Updated Cost |
|---|---|---|
| **Segments 1-3** | $257,600,000 | $746,000,000 |
| **Segments 4-11** | $1,800,000,000 | $2,435,000,000 |
| **Total TRTP** | **$2,057,600,000** | **$3,181,000,000** |

**Table 12 : DCR Cost Revisions[29]**

| Original FERC Filing | Updated Cost |
|---|---|
| $545,285,000 | **$944,800,000** |

Any estimate of the cost of SCE's SOK Upgrade should be looked at strictly as that, just an estimate. Based upon Edison's most current actual cost performance on similar undertakings, the SOK Upgrades may change significantly. The following cost calibration factors illustrate the significant change in SCE's cost for two of its current projects.

**Table 13 : SCE Cost Inflation/Updated SOK Estimate**

| Measure | TRTP | DCR | Weighted Average |
|---|---|---|---|
| **Total Increase** | 54.6% | 73.3% | **58.9%** |
| **Increase/mile** | $4.4M | $2.6M | **$3.7M** |
| **Increase/MW** | $234k | $333k | **$254k** |

ZGlobal proposes that CAISO and all other interested stakeholders take into consideration SCE's past performance on cost containment and extrapolate an estimate based on the current best available information.

[28] Data compiled from CPUC decision 07-03-012, 07-03-045, 09-09-033; CPUC Docket# A.07-06-03;1 and SCE Application 07-06-031
[29] Data from CPUC decision 07-01-040; SCE Advice Letter 2804-E

# Appendix A – Description of the Antelope Valley (AV) Clearview Project

The Antelope Valley (AV) Clearview Transmission Project is situated in the Antelope Valley surrounded by disturbed and largely vacant land. The project's key objective is to provide renewable energy developers access to a robust transmission system and increase the capacity for delivering this renewable energy to the load centers of southern California. Please see Figure 1.3 for the initial project layout and geographical location. The project consists of two options:

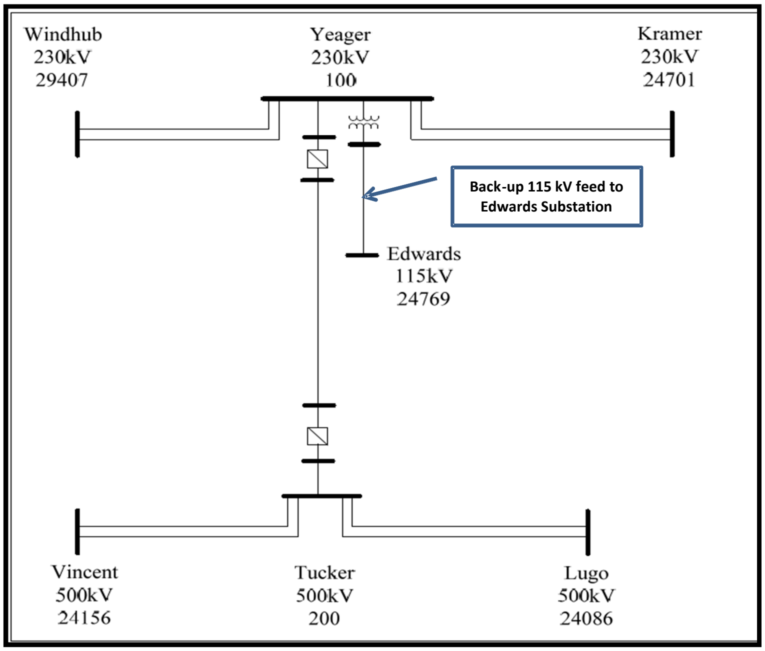
## A.1 Option 1 (Baseline Case)

The Project connects Southern California Edison's (SCE's) eastern bulk transmission system and resources around the Kramer area to the Tehachapi region or Northern bulk transmission system via a double circuit 230 kV transmission infrastructure. This option consists of the following transmission configurations (refer to Figure A.1):

1. New 230 kV Yeager Substation (near SCE's Edwards 115 kV substation)
2. New double circuit 230 kV from Windhub to Yeager
3. New double circuit 230 kV from Yeager to Kramer
4. New 230/115 kV step-down transformer bank at Yeager
5. New single circuit 115 kV from Yeager to SCE Edwards 115 kV substation (reliability back-up)
6. New 500 kV Tucker Substation in the community of Littlerock
7. New 1,000 MW capacity underground DC line between Yeager and Tucker Substation
8. Loop Lugo-Vincent #1 and #2 Lines through Tucker Substation
9. Converter units at the Yeager and Tucker substations

The estimated AV Clearview Project construction cost for the 1000 MW HVDC line, the Kramer-Yeager-Windhub 230 kV lines, including converter stations at Yeager and Tucker and the 115 kV back-up radial feeder line to Edwards Air Force Base is estimated at approximately $670 million.

**Figure A.1: One-line Diagram of Proposed Project (Option #1)**




## A.2 Option 2 (Expanded Case)

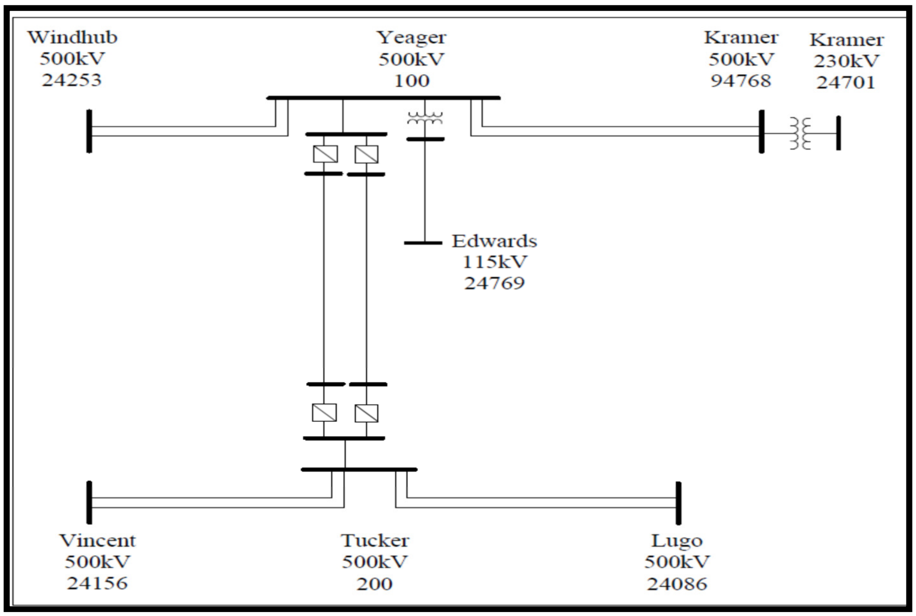
Connect the eastern transmission and resources around Kramer area to the Tehachapi area via 500 kV transmission facilities. Option 2 consists of the following transmission configurations (refer to Figure A.2):

New 500 kV Yeager Substation (near SCE's Edwards 115 kV Substation)

1. New double circuit 500 kV from Windhub to Yeager
2. New double circuit 500 kV from Yeager to Kramer
3. New 500/115 kV step-down transformer bank at Yeager
4. New single circuit 115 kV from Yeager to SCE Edwards 115 kV substation (reliability back-up)
5. New 500 kV Tucker Substation in the community of Littlerock
6. New 2000 MW capacity underground HVDC line between Yeager and Tucker Substation
7. Loop Lugo-Vincent #1 and #2 Lines through Tucker Substation
8. Converter units at the Yeager and Tucker substations

Project Cost for the 2,000 MW HVDC line, the 500 kV lines from Kramer-Yeager-Windhub, including converter stations at Yeager and Tucker is under review.

**Figure A.2: One-line Diagram of the Proposed Project (Expanded Option)**

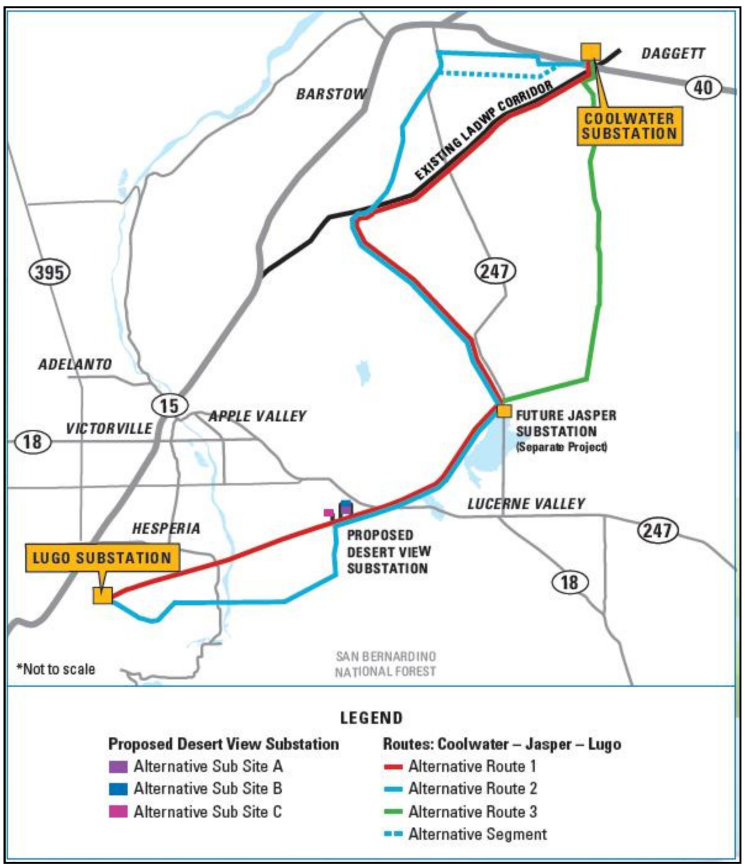


## Appendix B – Description of SCE's South of Kramer Proposed Upgrade

The alternative transmission project being evaluated by the CAISO in their 2012/2013 Transmission Planning Process (TPP) is referred to as the South of Kramer Upgrade or Coolwater-Lugo 230 kV project. The project will primarily consist of the following components[30]:

- **Transmission Lines** – Construction of approximately 55 to 70 miles of new high-voltage transmission lines between SCE's Coolwater Substation in Daggett, SCE's future Jasper Substation in Lucerne Valley (separate project), and SCE's Lugo Substation in Hesperia.
- **Substation** – Siting of a new Desert View Substation east of Apple Valley.
- **Substation Upgrades** – New electrical facilities at Coolwater Substation, Lugo Substation, and future Jasper Substation.

**Figure B.1: South of Kramer Upgrade approximate plan (Coolwater-Jasper-Lugo 220 kV transmission line)[31]**




[30] http://asset.sce.com/Documents/Environment%20-%20Transmission%20Projects/SOKFactSheet.pdf

[31] http://www.sce.com/popup/kramer-map.htm

The South of Kramer (SOK) project will be located in the Mojave Desert region of southern California. According to SCE, South of Kramer will provide capacity for up to 1,000 MW of new generation resources and will include the following: (1) 220 kV substation facilities at the existing Cool Water Generation Station Switchyard; (2) 220 kV and 500 kV substation facilities at the existing CAISO-controlled Lugo Substation; (3) approximately 47 miles of new 220 kV transmission lines and 16 miles of new 500 kV transmission lines, between the Cool Water Generation Station Switchyard and the Lugo Substation; (4) a new 220 kV switching station, to be called the Jasper Switching Station; (5) related telecommunications facilities; and (6) a new special protection system. According to SoCal Edison, South of Kramer will cost approximately $542 million and will be developed over seven years, and is expected to be in service in 2019.

SCE maintains that the South of Kramer (SOK) is a set of network upgrades necessary to provide increased transmission capacity to accommodate multiple generation projects in the CAISO interconnection queue, including five projects that constitute 591 MW of solar and wind generation. SCE states that its existing transmission facilities are inadequate to handle the proposed development of renewable generation in the area and, thus, it is proposing South of Kramer to ensure reliability and full delivery of the renewable generation in the area as it is integrated into the grid. [32]

The South of Kramer Upgrade (SOK) project as described above was included in the CAISO's 2011/2012 Transmission Plan renewable portfolio base cases. Subsequently, despite the approximate doubling of Kramer CREZ renewable base portfolio from 362 MW to 765 MW, the CAISO noted that in the 2012/2013 Transmission planning process the South of Kramer upgrade has been scaled back to some extent, thus reducing the ability to provide renewable capacity expansion from the Kramer region from the original 1,000 MW to no more than ~ 435 MW – with the use of a nomogram or special operating procedure(s) and/or remedial action scheme (RAS) – as well as the project cost estimate being reduced to ~ $480 million[33].

[32] SCE FERC Filing

[33] http://www.caiso.com/Documents/Presentation2012-2013TransmissionPlanningProcessStakeholderMeetingDec11-12_2012.pdf

# Appendix C – Economic Analysis, Assumptions and Detail Results Benefits

## C.1 Economic Benefit Categories

Economic benefits are quantifiable in dollar terms, and can be compared with the project's annual levelized cost to determine whether the project is a worthwhile endeavor. Economic benefits include the following Consumer and Societal benefits, which accrue to consumers, transmission owners, and generation owners:

1. Energy cost savings
2. Congestion cost reduction
3. Lower transmission losses and costs
4. Producer surplus

## C.2 Calculation of Economic Benefits

The benefits of the AV Clearview project are quantified in two components: (1) Consumer Benefit and (2) Societal Benefit. The Consumer Benefit is determined as the energy cost savings to buyers of energy in California. The Societal Benefit includes the Consumer Benefit, and add-on increases to production surplus and congestion revenue savings.

The Consumer and Societal Benefits for the project are determined utilizing the CAISO's Transmission Economic Assessment Methodology ("TEAM") approach which was adopted by the CPUC for use in economic evaluations of proposed transmission projects in Commission certificate of public convenience and necessity (CPCN) proceedings.[34] ZGlobal's analysis is prepared using PLEXOS for Power Systems for the production cost simulation.

The economic benefits of any transmission projects are highly sensitive to key assumptions or drivers such as:

1. Demand or load growth
2. Transmission projects schedule
3. Generation assumptions
4. New renewable generation penetration level
5. Natural Gas Prices

[34] Decision 06-11-018 November 9, 2006, "Opinion on Methodology for Economic Assessment of Transmission Projects"

6. Hydro conditions
7. Imports

Any changes in these primary drivers will results in different economic benefits. The rest of this Appendix shows an example of how these economic benefits are calculated based on the specific assumptions of each one of these drivers.

## C.3 Economic Assessment Assumptions

### C.3.1 Base Case Introduction

The PLEXOS model used in this study is based on the 2012-2022 model developed by ZGlobal. Further, this model based on the California Independent System Operator (CAISO) full network model. For the AV Clearview Project economic study, the model has been updated with the latest CAISO-approved transmission projects as documented in the 2011/2012 Transmission Plan, dated March 23, 2012[35], and uses the assumptions described in this document for demand forecast, generation, fuel price forecast, and imports for 2017 and 2019 scenario years. We simulated the entire 2017 year (8,760 hours) for the AV Clearview Project and the entire year of 2019 for SOK Upgrade (this is based on the assumptions that the SOK Upgrade has an in-service date of 2019).

ZGlobal estimated transmission benefits using a full network model. Modeling of power flows, constraints and congestion charges within the CAISO control area are included in the production cost simulation.

- Modeling of generation unit commitment and dispatch.
- Modeling of bilateral contracts and assumptions about future contracts.
- Assumptions about ownership of new generation facilities.

### C.3.2 Demand Forecast

The load forecast is modeled by utilizing the California Energy Commission (CEC) peak load forecasts as detailed in the "California Energy Demand 2012-2022, Final Forecast" report, dated June 2012[36] for the mid energy demand case. The particular details derived from the report are the electricity deliveries to end users (GWh) and the 1-in-10 Net Electricity Peak Demand (MW)

[35] http://www.caiso.com/Documents/Board-approvedISO2011-2012-TransmissionPlan.pdf

[36] Kavalec, Chris, Nicholas Fugate, Tom Gorin, Bryan Alcorn, Mark Ciminelli, Asish Gautam, Glen Sharp, and Kate Sullivan. 2012. *California Energy Demand Forecast 2012-2022 Volume 1: Statewide Electricity Demand and Methods, End-User Natural Gas Demand, and Energy Efficiency.* California Energy Commission, Electricity Supply Analysis Division. Publication Number: CEC-200-2012-001-CMF-VI.
Kavalec, Chris, Nicholas Fugate, Tom Gorin, Bryan Alcorn, Mark Ciminelli, Asish Gautam, Kate Sullivan, and Glen Sharp. 2012. *California Energy Demand Final Forecast 2012-2022 Volume 2: Electricity Demand by Utility Planning Area.* California Energy Commission, Electricity Supply Analysis Division. Publication Number: CEC-200-2012-001-CMF-VII.

for each Investor-Owned Utility (IOU). The peak load values are load and do not include losses or pump load. The tables below provide the 2015 and 2020 "1-in10" peak load and energy assumptions.

**Table C.1: 2017 Demand Forecast**

| 2017 1-in-10 Peak Demand MW and Annual GWh | | |
|---|---|---|
| **IOU** | Peak Demand (MW) | Annual GWh |
| **PG&E** | 24,070 | 108,924 |
| **SCE** | 26,297 | 99,625 |
| **SDG&E** | 5544 | 22,223 |

**Table C.2: 2018 Demand Forecast**

| 2018/19 1-in-10 Peak Demand MW and Annual GWh | | |
|---|---|---|
| **IOU** | Peak Demand (MW) | Annual GWh |
| **PG&E** | 24,362 | 110,062 |
| **SCE** | 26,638 | 100,646 |
| **SDG&E** | 5652 | 22,652 |

**Table C.3: 2020 Demand Forecast**

| 2020 1-in-10 Peak Demand MW and Annual GWh | | |
|---|---|---|
| **IOU** | Peak Demand (MW) | Annual GWh |
| **PG&E** | 24,985 | 112,908 |
| **SCE** | 27,319 | 103,073 |
| **SDG&E** | 5862 | 23,604 |

### C.3.3 Transmission Projects

ZGlobal's PLEXOS model has been updated to reflect the most recent list of approved Transmission Projects shown in Table C.4, consistent with CAISO's 2011/2012 Transmission Plan. Transmission projects that have received CAISO Board of Governors approval, or are associated with generation projects with executed LGIA's with the CAISO, were modeled in the AV Clearview analysis. The significant transmission projects include:

**Table C.4: CAISO Transmission Projects**

| Project Identification | On-Line Status | Comment |
|---|---|---|
| 1. **Carrizo-Midway** | 2012 | |
| 2. **Valley-Colorado River 500 kV** | 2013 | |
| 3. **Eldorado-Ivanpah 230 kV lines** | 2013 | |
| 4. **Tehachapi Renewable Transmission Project (TRTP)** | 2015 | Segments 1, 2, 3 Complete |
| 5. **Sunrise Powerlink** | 2012 | On Line |
| 6. **West of Devers Upgrade** | 2018 | |
| 7. **Coolwater-Lugo 230 kV line (South of Kramer Upgrades)** | 2018 | Not in Basecase or AV Case |
| 8. **South of Contra Costa reconductoring** | 2014 | Not yet permited |
| 9. **Borden-Gregg 230 kV line reconductoring** | 2015 | Not yet permited |
| 10. **Mirage-Devers 230 kV lines (Path 42)** | 2014 | Not yet permited |
| 11. **Whirlwind #2 and #3 transformers** | 2015 | LGIA generated |
| 12. **Imperial #3 transformer** | | |
| 13. **Humboldt 60 kV upgrades** | | |

Major new substations to be built and associated with transmission projects are the following:

**Table C.5: Major New Substations**

| Project Identification | On-Line Status | Comment |
|---|---|---|
| 1. **New ECO 500/138 kV (San Diego East County)** | ~ Late 2013 | CPUC/BLM Approved |
| 2. **New Red Bluff 500 kV** | 2014 | Due Dec/2013 |
| 3. **New Jasper 230 kV (part of South of Kramer Upgrades)** | 2018 | Substation triggered by LGIA |
| 4. **Ivanpah 230 kV** | 2013 | |

Additionally, the following projects identified by the Imperial Irrigation District (IID) to be needed to interconnect renewable generation in the IID system are modeled:

1. Coachella-Ramon-Mirage 230 kV lines upgrade (Path 42)
2. IID Imperial Valley-El Centro and Dixie 230 kV line

### C.3.4 Generation Assumptions

***Generation Additions and Retirements***

The base case assumes generation status based on both the published 2011/2012 CAISO Transmission Plan and the California Energy Commission (CEC) Energy Facility Status page on their website. The baseline case assumes the generation additions and retirements shown in the table below, based on the projects' current CEC status or as modeled in CAISO's policy driven base portfolio 2021 base cases which was the used as the basis for ZGlobal's reliability analysis.

**Table C.6: Major Generation Additions and Retirements**

| Generation | Status | Plexos Resource Name | Max Capacity |
|---|---|---|---|
| **Otay Mesa** | Online (2009) | OTAYM_1_GT 1<br>OTAYM_1_GT 2<br>OTAYM_1_ST | 606 MW |
| **El Cajon Energy Center** | Online (2010) | ELCAJN_6_LM6K | 48 MW |
| **Miramar 2** | Online (2010) | Q121_1_UNIT | 46 MW |
| **Orange Grove** | Online (2010) | OGE_1_UNIT 1<br>OGE_1_UNIT 2 | 96 MW |
| **Lake Hodges** | Online (2012) | LKHODG_1_UNIT 1<br>LKHODG_1_UNIT 2 | 40 MW |
| **Bullmoose** | Online (2013) | | 27 MW |
| **Carlsbad Energy Center** | Online (2016) | ENCINA_1_CT 1 | 558 MW |
| **South Bay** | Retired (2011) | | |
| **Encina 1-3** | Online (2015)<br>Retired (2016) | ENCINA_7_EA1<br>ENCINA_7_EA2<br>ENCINA_7_EA3 | 318 MW |
| **Kearny Peakers** | Retired (2014) | | 137 MW |
| **Pio Pico Energy Center** | 2014 | | 300 MW |
| **Quail Brush Generating Project** | 2014 | | 100 MW |
| **El Segundo Repower** | Online (2016) | ELSEGN_7_CT 5 | 570 MW |
| **Russell City Energy Center** | Online 7/2013 | | 600 MW |
| **Los Esteros CCGT** | Online 6/2013 | | 140 MW |
| **Walnut Creek Energy Ctr.** | Online by 2015 | | 500 MW |
| **Mariposa Energy Project** | Online 9/2012 | TOT334_1_CT 1 | 184 MW |

| | | | |
|---|---|---|---|
| **Marsh Landing** | Online 6/2013 | T320_1_GT1<br>T320_1_GT2 | 760 MW |
| **Oakley Generating Station** | Online 2016 | T305_1_CT 1<br>T305_1_CT 2<br>T305_1_ST 1<br>T305_1_ST 2 | 624 MW |
| **Sentinel Peaker** | Online 8/2013 | TOT032_1_G1 | 850 MW |
| **Tracy Combined Cycle** | Online 9/2012 | SCHLTE_1_ST1 | 145 MW |
| **Avenal Energy** | Online 2013 | T254_1_CTG1<br>T254_1_CTG2<br>T254_1_STG1 | 634 MW |
| **Hanford Combined-Cycle Power Plant** | Online 2/2013 | GWFPWR_1_ST 1 | 25 MW |
| **Henrietta Peaker Project Combined Cycle Expansion** | Online 2/2013 | HENRTA_6_UNITS1 | 25 MW |
| **Lodi Energy Center** | 2012 | TOT267_1_CT1<br>TOT267_1_ST1 | 254 MW |
| **Watson Cogeneration** | 2012 | T383_1_UNIT | 85 MW |

### *Once-Through-Cooled Power Plants*

The California Energy Commission (CEC) released a staff report in February of 2010 titled "The Roll of Aging and Once-Through-Cooled Power Plants in California – An Update".[37] Within the report the staff identifies all the Once-Through-Cooled (OTC) resources in California that the State Water Resources Control Board (SWRCB) recommends for replacement or elimination. Table C.7 outlines the list of OTC units by Local Capacity Area (LCR), along with the SWRCB proposed elimination dates and the status of each unit in the model used for the AV Clearview and SOK Studies.

**Table C.7: OTC Units in California**

| LCR Area | OTC Units | SWRCB Proposed Elimination Date | Notes | Generator Status for Studies |
|---|---|---|---|---|
| **Greater Bay Area** | Contra Costa 6 and 7 (340MW Each) | 2012 | Need replacement units or additional transmission into the bay to allow for retirement. | Re-power (Marsh Landing Generation Station 2012) |
| | Pittsburg 5 and 6 (325MW Each) | December 2017 | | On-line 2015, assumed retired before 2020 |
| | Potrero 3 (207MW) | December 2011 | | Retire |

[37] http://www.energy.ca.gov/2009publications/CEC-200-2009-018/CEC-200-2009-018.PDF

| | | | | |
|---|---|---|---|---|
| **Los Angeles Basin** | Alamitos 1 and 2 (175 Each) | December 2020 | Need replacement units or additional transmission into the bay to allow for retirement 2011/2012 Transmission Plan OTC Studies confirm capacity will likely be needed. We should check the owner's SWRCB replacement. Plan to identify upgrades or replacement project. Also, referenced table in Robert Sparks' presentation. | Online |
| | Alamitos 3 (326MW) | | | Online |
| | Alamitos 4 (324MW) | | | Online |
| | Alamitos 5 and 6 (485 Each) | | | Online |
| | El Segundo 3 and 4 (335MW Each) | December 2015 (re-power) | | Re-power project Combined Cycle 670 MW, HR=6500 |
| | Huntington Beach 1 and 2 (215 Each) | December 2020 | | Online (Repower project not online until Dec 2022) |
| | Huntington Beach 3 and 4 (225 Each) | December 2020 | | Online (but shut down if Walnut Creek energy center is online.) |
| | Redondo Beach 5 (179MW) | December 2020 | | Online (Repower project not Online until Dec 2022) |
| | Redondo Beach 6 (175MW) | December 2020 | | Online (Repower project not Online until Dec 2022) |
| | Redondo Beach 7 (493MW) | December 2020 | | Online (Repower by 2018?) |
| | Redondo Beach 8 (496MW) | December 2020 | | Online (Repower by 2018?) |
| **Big Creek/Ventura** | Mandalay 1 and 2 (218MW each) | December 2020 | Upgrade/Replacement Plan? | Online |
| | Ormond Beach 1 and 2 (806MW Each) | December 2020 | Repower project not online until Dec 2020. | Online |
| **San Diego** | Encina 1 (107MW) | December 2017 | Carlsbad Energy Center will replace this Assumed Carlsbad Energy Center online 2016. | Retire after 2017 |
| | Encina 2 (104MW) | December 2017 | | Retire after 2017 |
| | Encina 3 (110MW) | December 2017 | | Retire after 2017 |
| | Encina 4 (300MW) | December 2017 | Need replacement capacity. CAISO ran sensitivity if offline and found they needed upgrades because of addition of Pio Pico, Quail Brush and Escondido. | Online |
| | Encina 5 (330MW) | December 2017 | | Online |
| | South Bay 1 and 2 (136MW Each) | December 2012 | Not needed once Sunrise is in-service. | Retire |
| | South Bay 3 (210MW) | December 2012 | Not needed with addition of Otay Mesa. | Retire |
| | South Bay 4 (214MW) | December 2012 | | Retire |
| **Gas-Fired Not in LCR Area** | Morro Bay 3 and 4 (300MW Each) | December 2015 | Can retire without threatening reliability. Dynegy has no plan to re-power. | Retire |
| | Moss Landing 6 and 7 (702MW Each) | December 2017 | Would require replacement Capacity. | Online until Dec. 2017 |
| | Moss Landing 1 and 2 (540MW Each) | December 2017 | Would require replacement Capacity. | Stay Online – as is. Came online in 2002 |

### *Hydro Generation*

The hydro generation profiles were developed by utilizing a base hydro profile for each season, then scaling the base profile proportionately to the individual hydro stations. Similar curves have been developed for the pump storage resources in California, replacing the minimum output hours with pumping schedules.

- Spring: April 1 through June 31

- Summer: July 1 through September 30
- Fall/Winter: October 1 through March 31

The weekend and holiday dispatch is reduced due to the reduction in load. The hydro output is adjusted on average to be 25% less than the weekday dispatch.

The 2017 AV Clearview project economic study assumes an average hydro generation pattern. Table C.8 outlines the difference in total hydro output for each season in MWh.

**Table C.8: Seasonal Hydro MWh Comparison**

| Scenario | Spring | Summer | Fall/Winter | Total |
|---|---|---|---|---|
| **Avg** | 7,916,745 | 6,123,492 | 7,047,000 | 21,087,238 |

***Thermal Generation***

Natural gas fired generation resources are modeled using heat rates, start-up costs, minimum load, minimum up/down times, and ramp rates.[38] Additionally, Variable Operation and Maintenance Costs (VOM) can be included to reflect additional costs or bidding behavior. Where available, heat rates are based on bid data published by CAISO for periods in 2010 and 2011.[39] Table C.9 shows sample Incremental Heat Rate curves used in the model for the 3 natural gas fired generator types. For year 2015 and beyond, it is assumed that advances in generator efficiency will continue as has been the trend over the past 10 years. New generation additions are modeled with Heat Rates similar to resources that have come online between 2010 and 2012.

[38] In order to finesse the complexity that results from multi-stage generation, the production shares from heat-recovery steam generators (HRSGs) within combined cycle units are modeled as shared among gas-turbine units. For example, a combined-cycle resource with two 50-megawatt gas turbines and one 80-megawatt HRSG are instead modeled as two 90-megawatt gas turbines with heat rates to reflect the efficiency of the combined cycle resource.

[39] CAISO publishes bid data with reference identification numbers for each generator, in order to obscure the actual generator name and its corresponding bids. ZGlobal used known public information about the generation fleet, such as generator size, to match generators to bids to the extent possible. Where not possible, ZGlobal used other means to estimate heat rates. The other means primarily include the copying of bids of known generators to other generators whose actual bids are not known; or using representative general heat rate curves for specific resource types (combined cycle, gas turbine, steam turbine) from publicly available sources scaled to match the appropriate resource size.

**Table C.9: Heat Rate Curve Examples for 3 Types of Gas Fired Generators**

| Combined Cycle | | | |
|---|---|---|---|
| Load Point | 155 | MW | 1 |
| Load Point | 184 | MW | 2 |
| Load Point | 215 | MW | 3 |
| Load Point | 243 | MW | 4 |
| Load Point | 290 | MW | 5 |
| Load Point | 326 | MW | 6 |
| Load Point | 382 | MW | 7 |
| Load Point | 435 | MW | 8 |
| Load Point | 505 | MW | 9 |
| Load Point | 603.6 | MW | 10 |
| Heat Rate | 5994 | BTU/kWh | 1 |
| Heat Rate Incr | 6010 | BTU/kWh | 2 |
| Heat Rate Incr | 6707 | BTU/kWh | 3 |
| Heat Rate Incr | 7096 | BTU/kWh | 4 |
| Heat Rate Incr | 7124 | BTU/kWh | 5 |
| Heat Rate Incr | 7163 | BTU/kWh | 6 |
| Heat Rate Incr | 7193 | BTU/kWh | 7 |
| Heat Rate Incr | 7224 | BTU/kWh | 8 |
| Heat Rate Incr | 8925 | BTU/kWh | 9 |
| Heat Rate Incr | 8925 | BTU/kWh | 10 |

| Thermal | | | |
|---|---|---|---|
| Load Point | 10 | MW | 1 |
| Load Point | 50 | MW | 2 |
| Load Point | 95 | MW | 3 |
| Load Point | 121 | MW | 4 |
| Load Point | 141 | MW | 5 |
| Load Point | 151 | MW | 6 |
| Load Point | 161 | MW | 7 |
| Load Point | 175 | MW | 8 |
| Heat Rate | 7829 | BTU/kWh | 1 |
| Heat Rate Incr | 9747 | BTU/kWh | 2 |
| Heat Rate Incr | 9922 | BTU/kWh | 3 |
| Heat Rate Incr | 10108 | BTU/kWh | 4 |
| Heat Rate Incr | 10268 | BTU/kWh | 5 |
| Heat Rate Incr | 10376 | BTU/kWh | 6 |
| Heat Rate Incr | 10586 | BTU/kWh | 7 |
| Heat Rate Incr | 10586 | BTU/kWh | 8 |

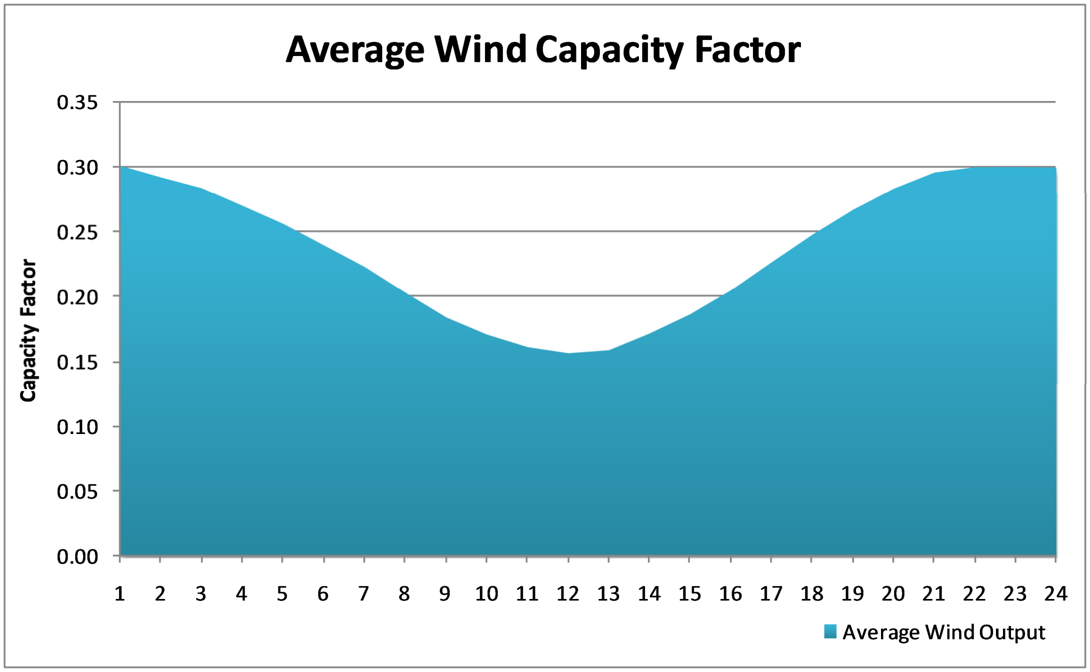
| Combustion Turbine | | | |
|---|---|---|---|
| Load Point | 18.2 | MW | 1 |
| Load Point | 45.42 | MW | 2 |
| Heat Rate | 10808 | BTU/kWh | 1 |
| Heat Rate Incr | 10808 | BTU/kWh | 2 |

***Wind Generation***

Wind generation resources are modeled using an approach similar to that of hydroelectric resource modeling. ZGlobal uses monthly capacity factors based on observed wind generation patterns as reported by the CAISO[40] to apply to individual wind resources as forecasted to be in service as of the subject forecast date. Wind generally produces the most power in the evening and less during the daytime hours. Figure C.1 illustrates the average base profile curve. The annual capacity factor of the modeled wind resources is 24%.

[40] http://www.caiso.com/market/Pages/ReportsBulletins/DailyRenewablesWatch.aspx

**Figure C.1: Wind Generation Profile**




***QF Generation***

Production by Qualifying Facility (QF) generation plants does not typically fluctuate on a large-scale throughout the day. These units are routinely dispatched at their maximum output.

For 2015, the majority of QFs will be reaching 25 to 30 years in operation. As such, these facilities are in general fully depreciated and no longer carry the financial burden of development and construction. Consequently, these facilities, even at significantly reduced energy contract prices, will continue to operate. The assumption is that even absent a contract these facilities will continue to produce energy and become active in the CAISO energy markets. This assumption is driven by the economics, in that the facilities are fully depreciated and capable of earning a profit even if simply generating into the ISO uninstructed and earning the Real-time LMP. Regardless of their approach to the market, it is expected that they will continue to run at maximum output.

***Solar Generation***

An approach similar to that used for wind is used to develop solar production curves. Production by Solar generation plants is assumed to peak in the summer months and produce the most during the daylight hours. See Figures C.2 and C.3 for illustrations of the solar dispatch.

**Figure C.2: Average Capacity Factor**

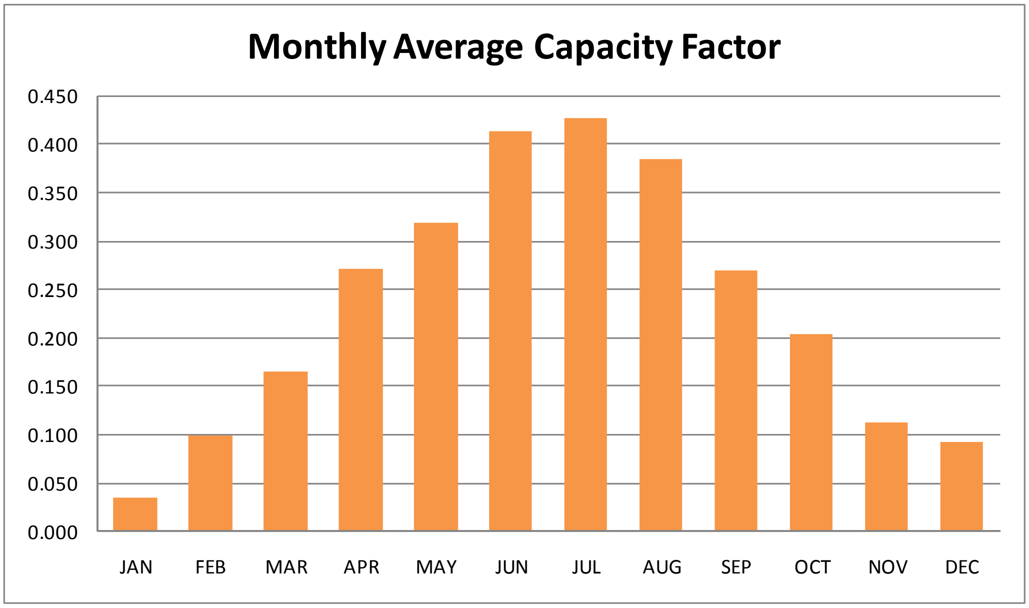
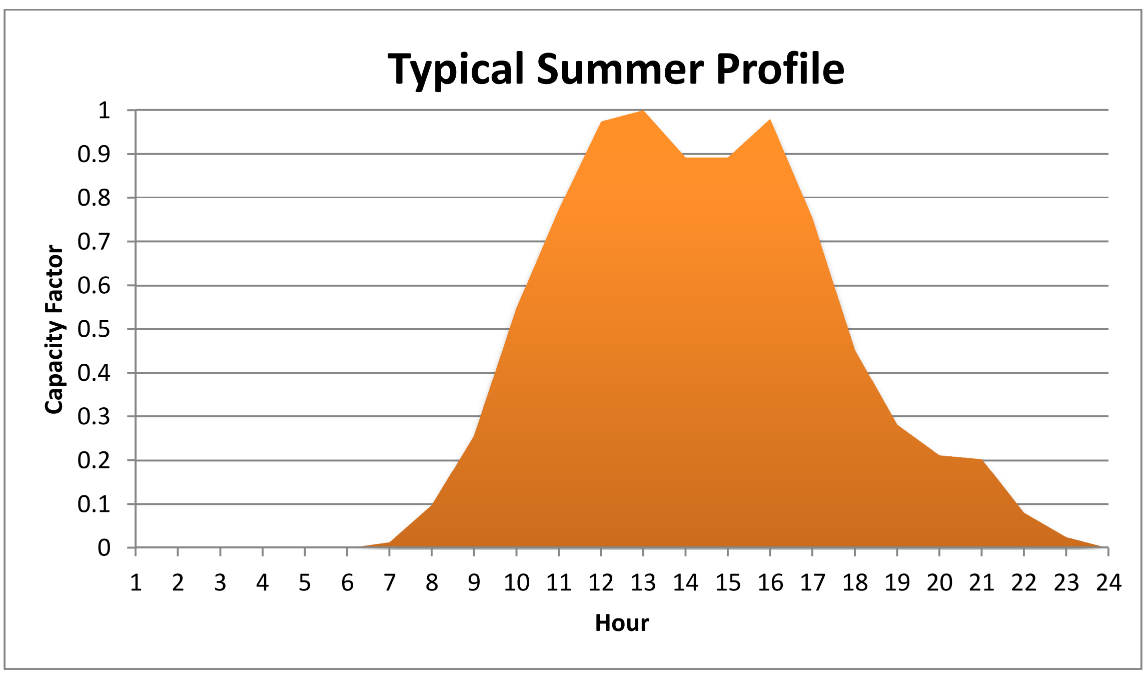



**Figure C.3: Typical Daily Summer Profile**




***Biomass Generation***

The production profile of Biomass generation is assumed to be constant throughout the day and fluctuate slightly by season. The assumption for the daily peak annual profile dispatch ranges between .80 to 1.0 capacity factor for summer and winter respectively.

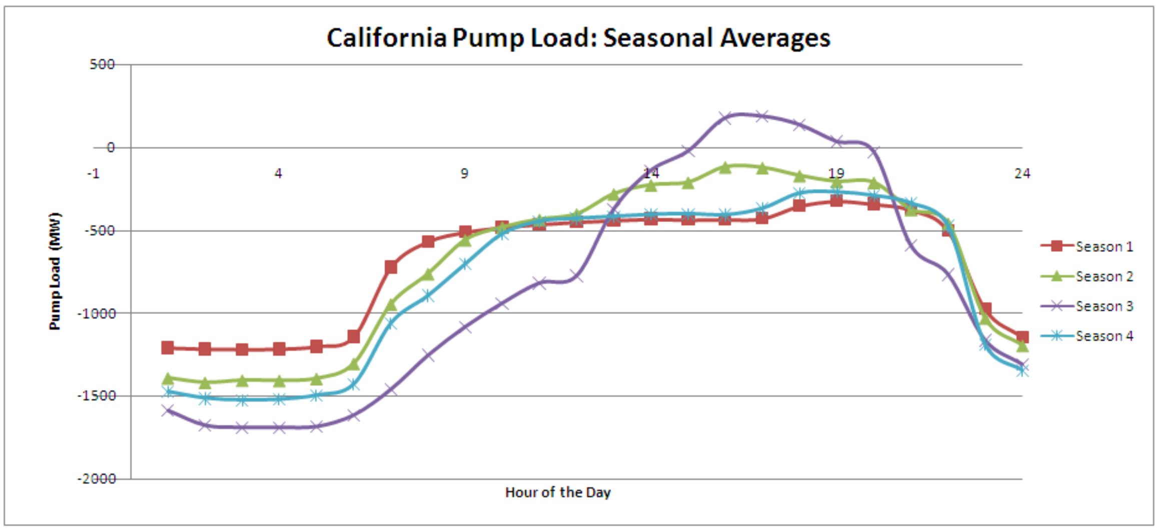
***Geothermal Generation***

The production profile of Geothermal generation is assumed to be at full load during peak hours and 95% of full during the off peak hours. During the summer months however, there is a slight de-rate associated with the higher temperatures. The profile is assumed 95% of full load on and off peak during the summer months.

***California Pumps***

The California aqueduct imposes a significant amount of load on the system. Figure C.4 provides a breakdown of the pump dispatch based on seasonal averages.

**Figure C.4: California Pump Load**




### C.3.5 Renewable Energy Projects Summary

To rationalize and support the estimated renewable energy level injected into the ZGlobal Model, ZGlobal reviewed the CAISO interconnection queue and the CPUC's RPS contracts data. The premise for this review was to compare the various 33% RPS generation portfolios. From the CAISO interconnection queue, the table below displays the MW summaries (in $P_{max}$) of projects in the Tehachapi region which have either executed an Interconnection Agreement or are in-progress of executing an Interconnection Agreement, or are complete and on-line as of August 28, 2012. The TRTP build out is targeted for completion in early 2015 and so the ZGlobal model assumes 5,378 MW of available new Tehachapi region wind and solar generation projects at the following major substations.

The following table summarizes modeled renewable energy in the Tehachapi area.

**Table C.10: Tehachapi Area Modeled Renewable Generation**

| Location | Type | MW |
|---|---|---|
| **Windhub** | Wind | 2,269 |
| **Whirlwind** | Wind | 1,500 |
| | Solar | 1,050 |
| **Vincent/Antelope** | Wind | 453 |
| | Solar | 106 |
| **Totals** | Wind | 4,222 |
| | Solar | 1,156 |
| Total | | **5,378** |

The April CPUC Renewable Contract Status spreadsheet, presented below, shows that there are presently approximately 1113 MW connected and on-line in the Tehachapi region.

**Table C.11: Tehachapi Area Renewable Generation (PPA On-Line)[41]**

| Projects Approved and Online | Status | IOU | Min MW | Min Expected GWh/yr | Technology | Vintage | Contract Term (years) | Location | Online Date/Contracted Delivery Date |
|---|---|---|---|---|---|---|---|---|---|
| Coram CellC | Operational | SDG&E | 8 | 27 | wind | existing | 15 | Tehachapi | 11/27/10 |
| Oasis Power Partners | Operational | SDG&E | 60 | 179 | wind | new | 15 | Mojave | 12/31/04 |
| Alta I | Operational | SCE | 150 | 452 | wind | new | 20 | Tehachapi | 01/06/11 |
| Alta II | Operational | SCE | 150 | 380 | wind | new | 20 | Tehachapi | 01/01/11 |
| Alta III | Operational | SCE | 150 | 423 | wind | new | 20 | Tehachapi | 02/14/11 |
| Alta IV | Operational | SCE | 102 | 240 | wind | new | 20 | Tehachapi | 03/10/11 |
| Alta V | Operational | SCE | 168 | 390 | wind | new | 20 | Tehachapi | 04/20/11 |
| Alta VIII | Operational | SCE | 150 | 473 | wind | new | 20 | Tehachapi | 02/01/12 |
| Alta VI | Operational | SCE | 150 | 473 | wind | new | 20 | Tehachapi | 01/01/12 |
| Boxcar II | Operational | SCE | 8 | 20 | wind | repower | 30 | Tehachapi | 01/01/05 |
| Coram Energy | Operational | SCE | 3 | 11 | wind | repower | 30 | Tehachapi | 04/01/06 |
| CTV Power | Operational | SCE | 14 | 41 | wind | repower | 30 | Tehachapi | 04/01/06 |

The following table summarizes the Tehachapi Region RPS Contracts which have been approved for projects under development.

[41] Source: CPUC RENEWABLE_PPA_Project_Status_Table_2012_April

**Table C.12: Tehachapi Area Renewable Generation with Executed PPA and Under Development**

| Tehachapi Group (incl. - Kern [Wind & PV] / Los Angeles) | # of Projects | MW |
|---|---|---|
| Total MW | 23 | 2176 |
| Total Projects | | |
| Bio | 3 | 24 |
| PV Solar | 8 | 1048 |
| Solar Thermal | 0 | |
| Wind | 12 | 1104 |

For the other regions (San Diego/Imperial and Riverside), the following data is provided:

- San Diego/Imperial CAISO Queue data (table below) with either an executed Interconnection Agreement or are in-progress of executing an Interconnection Agreement, or are complete and on-line as of August 28, 2012 data point.

**Table C.13: San Diego/Imperial Area Renewable Generation (CAISO Queue)**

(*Note: there is also 40 MW Pump Storage and 27 MW Biomass*)

| Year 2017 | | |
|---|---|---|
| **Location** | **Type** | **MW** |
| Imperial Valley Sub | Solar | 1,175 |
| Other (internal to SDG&E) | Wind | 717.5 |
| | Solar | 25.75 |
| **2017 San Diego/Imperial Area Total** | | **1,918.25** |
| **Year 2018** | | |
| **Location** | | **MW** |
| Imperial Valley Sub | Solar | 1,625 |
| Other (internal to SDG&E) | Wind | 717.5 |
| | Solar | 25.75 |
| **2018 San Diego/Imperial Area Total** | | **2,368.25** |

San Diego/Imperial RPS Contracted – Approved Under Development

**Table C.14: San Diego/Imperial Area Renewable Generation (PPA)**

| San Diego-Imperial Group | # of Projects | MW |
|---|---|---|
| Total MW | 17 | 1323 |
| Total Projects | | |
| Bio | 0 | |
| PV Solar | 13 | 929 |
| Solar Thermal | 1 | 49 |
| Wind | 1 | 265 |
| Geothermal | 2 | 80 |

East Riverside region CAISO Queue data (table below) with either an executed Interconnection Agreement or are in-progress of executing an Interconnection Agreement, or are complete and on-line as of August 28, 2012 data point.

**Table C.15: Riverside Area Renewable Generation (CAISO Queue)**

| Location | Type | MW |
|---|---|---|
| Colorado River | Wind | 0 |
| | Solar | 1,985 |
| Red Bluff | Wind | 0 |
| | Solar | 1,250 |
| Devers | Wind | 267 |
| | Solar | 49.5 |
| **Total** | | **3,551.5** |

Riverside RPS Contracted – Approved Under Development

**Table C.16: Riverside Area Renewable Generation (PPA)**

| Riverside | # of Projects | MW |
|---|---|---|
| Total Riverside MW | 7 | 1476 |
| Total Riverside Projects | | |
| Bio | 1 | 2 |
| PV Solar | 2 | 550 |
| Solar Thermal | 3 | 884 |
| Wind | 1 | 40 |

Renewable generation from outside California is included in the ZGlobal Model. However, flows on interties are modeled to include such generation where appropriate.

**Kramer-Pisgah-Lugo Regional Generation**

A look at the most recent CAISO Interconnection Queue for the Kramer, Pisgah and Lugo region provides the following data.

## Table C.17: Kramer-Pisgah-Lugo Regional Generation Queue

| Queue Position | Application Status | Study Process | Type-1 | Fuel-1 | MW Total | Full Capacity, Partial or Energy Only (FC/P/EO) | County | State | Utility | Station or Transmission Line | Current On-line Date | Interconnection Agreement Status |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 68 | Active | Serial | PV | S | 850 | | SAN BERNARDINO | CA | SCE | Pisgah Sub 230 kV Bus | 3/31/2013 | Complete |
| 125 | Active | Serial | ST | S | 250 | | SAN BERNARDINO | CA | SCE | Coolwater-Kramer 230kv line | 12/1/2013 | Complete |
| 131 | Active | Serial | ST | S | 100 | | SAN BERNARDINO | CA | SCE | Eldorado-Baker-Cool Water-Dunn Siding-Mountain Pass 115kV line | 8/14/2012 | Complete |
| 135 | Active | Serial | WT | W | 60 | | SAN BERNARDINO | CA | SCE | Lugo-Pisgah 230kV line | 7/31/2015 | Complete |
| 142 | Active | Serial | ST | S | 80 | | SAN BERNARDINO | CA | SCE | Kramer Substation 220kV | 4/1/2016 | In Progress |
| 162 | Active | Serial | ST | S | 114 | | SAN BERNARDINO | CA | SCE | Eldorado-Baker-Cool Water-Dunn Siding-Mountain Pass 115kV line | 7/1/2013 | Executed |
| 240 | Active | Serial | ST | S | 400 | | SAN BERNARDINO | CA | SCE | Pisgah Sub 230kV | 6/30/2014 | In Progress |
| 241 | Active | Serial | ST | S | 400 | | SAN BERNARDINO | CA | SCE | Pisgah Sub 230kV | 6/30/2015 | In Progress |
| 552 | Active | C2 | PV | S | 60 | FC | SAN BERNARDINO | CA | SCE | Lugo-Pisgah #1 230kV | 4/30/2013 | In Progress |
| 589 | Active | C2 | PV | S | 60 | FC | SAN BERNARDINO | CA | SCE | Victor Substation 115kV | 9/1/2013 | In Progress |
| 888 | Active | C5 | PV | S | 100 | FC | SAN BERNARDINO | CA | SCE | Jasper 220 kV | 10/15/2015 | |
| 892 | Active | C5 | STH | S | 270 | FC | SAN BERNARDINO | CA | SCE | Pisgah Substation 220kV bus | 12/31/2015 | |
| 897 | Active | C5 | PV | S | 200 | FC | SAN BERNARDINO | CA | SCE | Jasper Substation 220kV bus | 12/1/2016 | |
| 909 | Active | C5 | ST | S | 25 | FC | SAN BERNARDINO | CA | SCE | Water Valley Substation 220kV | 2/11/2014 | |
| 942 | Active | C5 | PV | S | 250 | FC | KERN | CA | SCE | Kramer Substation 220kV bus | 4/30/2016 | |

Disregarding the highlighted generation in the table above (as it is presumed to be interconnecting to the new Ivanpah substation), there is presently 3,005 MW of queued generation. Of that, 2,160 MW have executed or are in the process of executing their Interconnection Agreements.

From SCE's WDAT queue the following generation is identified for the Kramer, Pisgah and Lugo region.

**Table C.18:** SCE's WDAT queue positions

| Project Number | Tariff | Request Type | Study Group | IA Executed(Y/N) | Technology | Facility Max Export Req(MW) | Facility County | Current Requested Facilities In-Service Date | Current Point of Delivery |
|---|---|---|---|---|---|---|---|---|---|
| WDT164 | WDAT | LGIP | Serial | Yes | Wind | 80 | San Bernardino | 9/1/2010 | Victor Substation |
| WDT301 | WDAT | SGIP | Serial | No | Solar PV | 0.612 | Kern | 12/31/2008 | Kramer 115kV Bus |
| WDT372 | WDAT | SGIP | Serial | Yes | Solar | 20 | San Bernardino | 6/30/2012 | Victor 220kV bus |
| WDT406 | WDAT | SGIP | Serial | No | Solar PV | 3 | San Bernardino | 12/15/2011 | Victor 220kV bus |
| WDT409 | WDAT | SGIP | Serial | No | Solar PV | 10 | San Bernardino | 12/1/2012 | Victor 220kV bus |
| WDT421 | WDAT | SGIP | Serial | No | Solar PV | 20 | San Bernardino | 6/30/2012 | Victor 220kV bus |
| WDT491 | WDAT | SGIP | Serial | No | Solar PV | 20 | San Bernardino | 6/30/2012 | Victor 220kV bus |
| WDT508 | WDAT | SGIP | Fast Track | No | Solar PV | 2 | San Bernardino | 5/31/2011 | Victor 220kV bus |
| WDT531 | WDAT | SGIP | Fast Track | No | Solar PV | 1.56 | San Bernardino | 1/1/2012 | Victor 220kV bus |
| WDT532 | WDAT | SGIP | Fast Track | No | Solar PV | 1.56 | San Bernardino | 1/1/2012 | Victor 220kV bus |
| WDT533 | WDAT | SGIP | Fast Track | No | Solar PV | 0.62 | San Bernardino | 1/1/2012 | Victor 220kV bus |
| WDT617 | WDAT | SGIP | Fast Track | No | Solar PV | 2 | San Bernadino | 12/31/2013 | Victor 220kV bus |
| WDT618 | WDAT | SGIP | Fast Track | No | Solar PV | 2 | San Bernadino | 12/31/2013 | Victor 220kV bus |
| WDT646 | WDAT | SGIP | Serial | No | Solar PV | 5 | San Bernadino | 12/31/2013 | Victor 115 kV Substation |
| WDT647 | WDAT | SGIP | Serial | No | Solar PV | 5 | San Bernadino | 12/31/2013 | Victor 115 kV Substation |
| WDT648 | WDAT | SGIP | Fast Track | No | Solar PV | 2 | San Bernadino | 12/31/2013 | Victor 220kV bus |
| WDT649 | WDAT | SGIP | Serial | No | Solar PV | 5 | San Bernadino | 12/31/2013 | Victor 220kV bus |
| WDT650 | WDAT | SGIP | Fast Track | No | Solar PV | 2 | San Bernadino | 12/31/2013 | Victor 220kV bus |
| WDT651 | WDAT | SGIP | Fast Track | No | Solar PV | 2 | San Bernadino | 12/31/2013 | Victor 220kV bus |
| WDT854FT | WDAT | GIP - Fast Track | Fast Track | Yes | solar PV | 1.5 | San Bernardino | 6/30/2012 | Victor 220/115 |
| WDT883QFC | WDAT | Distribution Service | QF Conversion | Yes | | 55 | Kern | 7/1/2013 | The ISO Grid at SCE's Kramer 115kV substation |
| WDT901 | WDAT | GIP - Cluster Study | QC_005 | No | Photovoltaic | 5 | San Bernardino | 12/31/2014 | Victor Substation 115 kV bus |
| WDT905 | WDAT | GIP - Cluster Study | QC_005 | No | Photovoltaic | 50 | Kern | 1/10/2015 | Kramer Substation 115 kV bus |
| WDT925 | WDAT | GIP - Cluster Study | QC_005 | No | Photovoltaic | 20 | San Bernardino | 4/1/2015 | Victor Substation 115 kV bus |
| WDT927 | WDAT | GIP - Cluster Study | QC_005 | No | Photovoltaic | 35 | Kern County | | Holgate Substation 115 kV bus |
| WDT930 | WDAT | GIP - Cluster Study | QC_005 | No | Photovoltaic | 20 | San Bernardino County | | Cool Water Substation 115 kV bus |
| WDT931 | WDAT | GIP - Cluster Study | QC_005 | No | Photovoltaic | 20 | San Bernardino County | | Tortilla Substation 115 kV bus |

An estimated 391 MW of SCE WDAT queued generation are indicated with immediate regional impact providing an estimated total of 3,396 MW of Kramer-Pisgah region queued generation projects. Assuming an attrition rate of 50% provides a range of 1,698 MW to 2,547 MW of viable renewable generation in the region.

### C.3.6 Fuel Forecast

2017 fuel prices ($$/MMBtu) are based on ICE OTC energy market end-of-day report for 8/28/2012 and include delivery point adjustments (Table C.19).

**Table C.19: 2015 and 2020 Fuel Price Assumptions**

| 2017 | | | |
|---|---|---|---|
| Month | PG&E | SCE/SDG&E | IMPORT |
| Jan | 5.107 | 5.0545 | 4.732 |
| Feb | 5.078 | 5.0005 | 4.7005 |
| Mar | 5.002 | 4.9445 | 4.632 |

| 2017 | | | |
|---|---|---|---|
| Month | PG&E | SCE/SDG&E | IMPORT |
| Apr | 4.8845 | 4.6495 | 4.3895 |
| May | 4.9045 | 4.717 | 4.4095 |
| Jun | 4.9305 | 4.7555 | 4.4355 |
| Jul | 4.9725 | 5.015 | 4.4775 |
| Aug | 4.9945 | 5.007 | 4.4995 |
| Sep | 4.9995 | 4.8495 | 4.5045 |
| Oct | 5.0395 | 4.8245 | 4.5445 |
| Nov | 5.06 | 4.94 | 4.635 |
| Dec | 5.27 | 5.1775 | 4.895 |
| 2018 | | | |
| Month | PG&E | SCE/SDG&E | IMPORT |
| Jan | 5.382 | 5.3195 | 5.007 |
| Feb | 5.354 | 5.269 | 4.9765 |
| Mar | 5.279 | 5.2115 | 4.909 |
| Apr | 5.1665 | 4.934 | 4.6715 |
| May | 5.1865 | 4.969 | 4.6915 |
| Jun | 5.2165 | 5.0215 | 4.7215 |
| Jul | 5.2615 | 5.284 | 4.7665 |
| Aug | 5.2815 | 5.294 | 4.7865 |
| Sep | 5.2865 | 5.1165 | 4.7915 |
| Oct | 5.3265 | 5.069 | 4.8315 |
| Nov | 5.351 | 5.2285 | 4.926 |
| Dec | 5.568 | 5.4455 | 5.193 |

| 2020 | | | |
|---|---|---|---|
| Month | PG&E | SCE/SDG&E | IMPORT |
| Jan | 5.999 | 5.8965 | 5.639 |
| Feb | 5.974 | 5.859 | 5.6115 |
| Mar | 5.902 | 5.802 | 5.547 |
| Apr | 5.7695 | 5.5495 | 5.3145 |
| May | 5.8315 | 5.664 | 5.3365 |
| Jun | 5.8615 | 5.699 | 5.3665 |
| Jul | 5.9065 | 5.9015 | 5.4115 |
| Aug | 5.9285 | 5.9135 | 5.4335 |
| Sep | 5.9345 | 5.737 | 5.4395 |
| Oct | 5.9745 | 5.6895 | 5.4795 |

| | | | |
|---|---|---|---|
| Nov | 6.005 | 5.8575 | 5.58 |
| Dec | 6.24 | 6.1275 | 5.865 |

### C.3.7 Imports

Each import is designated as one of two types: Base Loaded and Mixture. Base Loaded imports are modeled as pre-defined hourly dispatches at the relevant import location using historical flows.

Import locations designated as "Mixture" are modeled with a Heat Rate curve to represent a range of generation imported from outside the CAISO. The Heat Rates in Table C.20 is an example of the curve that is used in the model.

**Table C.20: Example of Heat Rate Modeling for Import of Mixed Resource Types**

| Number of Pairs | Heat Rate |
|---|---|
| Load Point | 25 |
| Load Point | 36 |
| Load Point | 55 |
| Load Point | 77.5 |
| Load Point | 92.5 |
| Load Point | 100 |
| Heat Rate | 1000 |
| Heat Rate | 7700 |
| Heat Rate | 9700 |
| Heat Rate | 10350 |
| Heat Rate | 11400 |
| Heat Rate | 11850 |

## C.4 Calculation of Consumer Benefit

Under discrete set of assumptions, ZGlobal modeled the Grid along with all the input data utilizing a well knows production cost software ("PLEXOS") to calculate the economic benefit of the AV Clearview and the SOK projects from the Consumer perspectives ("Consumer Benefits") and from the Societal perspectives ("Societal Benefits").

The objective for the Consumer Benefit calculation is to evaluate how consumer costs of energy change with the addition of a project. The reduction in energy cost is mainly driven by the differentials in nodal prices under locational marginal pricing (LMP). The LMP price differentials are attributable to differences in marginal fuel costs (captured as the difference in the marginal cost of energy) and marginal line losses by location with AV Clearview and without AV Clearview.

Within PLEXOS, ZGlobal models the full network topology of the CAISO footprint and calculates the generation and ancillary service dispatch, transmission flow and LMPs for 8,760 hours in the study year, 2017. For each hour of the year, a production cost simulation is performed under a base case scenario without AV Clearview in-service and then again with AV Clearview interconnected. Cost savings or benefits to California market participants are calculated by comparing the costs paid by market participants in the two scenarios. If costs are lower with the AV Clearview project in-service, then there is a net benefit.

The outputs of the PLEXOS modeling and production cost simulation are Locational Marginal Prices (LMPs) for each supply and demand location in the CAISO including the three LMP components, for the Marginal Cost of Congestion (MCC), the Marginal Cost of Losses (MCL) and the system Marginal Energy Cost (MCE), transmission line flows, dispatch levels and production costs for each supply resource. The PLEXOS results are integrated into ZGlobal's GridSelect analytical tools to calculate CAISO Load Aggregation Point (LAP) prices, CAISO Trading Hub prices and economic factors consistent with settlement cost calculations in accordance with CAISO market rules. The hourly economic factors are then used to calculate potential energy cost savings of the AV Clearview project from the perspective of California market participants using the methodology and computations described herein.

Thus, the analysis quantifies Consumer Benefits by comparing the costs of energy (including losses and congestion) borne by CAISO consumers with the AV Clearview Transmission Project in service, to the costs of energy if that project were not built. The added transmission line is expected to enable lower-cost suppliers of power to serve load and displace high-cost producers in the SCE load pocket.

For the 2017 study year with the AV Clearview Project in place, the calculated Consumer Benefit is \$131.3 million. The AV Clearview levelized annual benefits to consumers in \$2017 with 1% net escalation of benefit per year is \$147.6 million with an NPV of \$1.8 billion[42]

**AV Clearview**

**Benefit to Load**

**BTL = -1 * Δ(LMC - MLS)**

[42] All NPV are calculated at a WACC of 8.3%

| | AVCV Project |
|---|---|
| **2017 Total** | **$131,268,958** |

For the 2019 study year with the SOK Upgrade in place, the calculated Consumer Benefit is $82.6 million:

| **SOK** | **Benefit to Load** |
|---|---|
| | **BTL = -1 * Δ(LMC - MLS)** |
| | **SOK Upgrade** |
| **2019 Total** | **$82,624,470** |

The SOK levelized annual benefits to consumers in $2017 with 1% net escalation of benefit per year is $80.0 million and the NPV in $2017 is equal to $993 million.

The Consumer Benefit or "Benefit to Load" (BTL) due to Energy cost savings is calculated each hour *t* as:

$BTL_t = -1 * (\Delta LMC_t – \Delta MLS_t)$

Where,
$\Delta LMC_t$ is the savings to consumers' total Load Market Cost for hour *t*
$\Delta MLS_t$ is the decrease in Marginal Loss Surplus refunded to consumers for hour *t*
We use a (-1) multiplier to indicate a positive dollar amount represents a cost savings to the consumer. The hourly Consumer Benefits are summed for the entire year to get the net yearly Consumer Benefit.

### C.4.1 Load Market Cost Calculation (LMC)

$\Delta LMC_t$ is the savings to consumers' total Load Market Cost (LMC). It is calculated as the cost difference between the LMC with and without the project (or between the Baseline and the change case).

$\Delta LMC_t = LMC_{t\ w} – LMC_{t\ w/o}$
where,
$LMC_{t,w}$ = the consumer's market cost ($) with the project or the change case for hour *t*
$LMC_{t,w/o}$ = the consumer's market cost ($) without the project or the Baseline case for hour *t*

The hourly $\Delta LMC_t$ are summed for the entire year to determine the yearly Load Market Cost savings. The $\Delta LMC_t$ for the AVCV Project and SOK Upgrade scenarios are -$127 million and

-$89.8 million respectively, where a negative dollar amount indicates the energy cost savings with the project.

| AV Clearview Project | Load Market Cost (LMC) LMC = Load * LAP LMP | | Delta |
|---|---|---|---|
| | B | S1 | |
| 2017 Total | $8,617,446,051 | $8,490,469,176 | -$126,976,875 |

| SOK Upgrade | Load Market Cost (LMC) LMC = Load * LAP LMP | | Delta |
|---|---|---|---|
| | B | S2 | |
| 2019 Total | $9,213,399,229 | $9,123,584,872 | -$89,814,357 |

Consumers or the Demand in CAISO is charged a weighted average nodal price specific to its Load Aggregation Point (LAP LMP). There are 3 LAPs defined: a) PG&E, b) SCE and c) SDG&E. The LAP LMP includes not only the marginal cost of energy but also the costs paid for congestion and losses. For our analysis, we will include the marginal energy, marginal congestion and marginal loss cost paid by consumers when determining the hourly (t) Load Market Cost (LMC) as follows:

$$LMC_t = \sum_i (DemandMWh_{i,t} * LAP\_LMP_t)$$

where,

$Demand\ MWh_{i,t}$ = Demand (MWh) in Load Aggregation Point (LAP) *i* for hour *t*, and

$LAP\_LMP_{i,t}$ = the LMP for LAP *i,* hour *t* ($/MWh)

The LMC paid by consumers includes the charge to Demand for marginal losses, or MCL. The MCL for the system represents the net cost of losses paid by consumers at the marginal loss rates. The marginal loss component of the LMP charges consumers for the incremental quantity (MWs) of transmission losses in the network resulting when serving an increment of load at the LAPs from the CAISO-determined Baseline busses. With this methodology, consumers are "over-charged" for losses compared with if charged based on the actual MW difference between supply and demand which are the actual losses in the system. Any amount "overcollected" are termed "Marginal Loss Surplus" and are refunded back to consumers in the CAISO settlement process. For the analysis, the decrease in Marginal Loss Surplus (MLS) is subtracted from the LMC savings when calculating the net Consumer Benefit for Energy costs.

### C.4.2 Marginal Loss Surplus (MLS) Calculation

The Marginal Loss Surplus (MLS) is derived each hour *t* as the difference between the Transaction Costs and the Congestion Cost. The MLS represents over-collection of costs associated with marginal losses. MLS cannot be considered a net benefit to load. Per CAISO settlement rules entities representing Demand are refunded these costs during the settlements process and thus are excluded from the total Consumer Benefits.

$$MLS_t = TC_t - CR_t$$

where,
$TC_t$ = Transaction Costs for hour *t* for all CAISO market participants
$CR_t$ = Congestion Cost for hour *t* for all CAISO market participants

And, the Marginal Loss Surplus reduction,

$$\Delta MLS_t = MLS_{t,w} - MLS_{t,w/o}$$

where,
$MLS_{t,w}$ = the system's Marginal Loss Surplus with the Project ($) for hour *t*,
$MLS_{t,w/o}$ = the system's Marginal Loss Surplus without the Project ($) for hour *t*

The $\Delta MLS_t$ for the AVCV Project and SOK Upgrade scenarios are $4.3 Million and -$7.2 Million respectively:

| AV Clearview Project | Marginal Loss Surplus (MLS)<br>MLS = TC-CR | | Delta |
|---|---|---|---|
| | B | S1 | |
| 2017 Total | $154,259,739 | $158,551,822 | $4,292,083 |

| SOK Upgrade | Marginal Loss Surplus (MLS) | | Delta |
|---|---|---|---|
| | MLS = TC-CR | | |
| | B | S2 | |
| 2019 Total | $106,504,445 | $99,314,558 | -$7,189,887 |

### C.4.3 Transaction Cost (TC) Calculation

In the CAISO markets, suppliers are paid the nodal-specific LMP while consumers are charged a weighted-average LMP for its Load Aggregation Point (LAP). Since LMPs reflect the marginal cost of congestion and losses to inject or withdraw energy at that pricing point, the difference between what consumers are charged and what suppliers are paid reflect the total system congestion and loss cost for transferring energy between the nodal injection points and the LAPs where load withdraws the energy. For this analysis, we refer to this as the system Transaction Costs.

In the CAISO, there are three LAP areas (PG&E, SCE and SDG&E) with separate weighted-average LMPs (or LAP LMPs). The system Transaction Cost is calculated for each hour *t* in the study period as follows:

$$TC_t = \left(\sum_i DemandMWh_{i,t} * LAP\_LMP_{i,t}\right) - \sum_k \left(SupplyMWh_{k,t} * LMP_{k,t}\right)$$

$$LAP\_LMP_{i,t} = MCE_t + LAP\_MCC_{i,t} + LAP\_MCL_{i,t}$$

$$LMP_{k,t} = MCE_t + MCC_{k,t} + MCL_{k,t}$$

where,

$Demand\ MWh_{i,t}$ = Demand (MWh) in Load Aggregation Point (LAP) *i* for hour *t*

$LAP\_LMP_{i,t}$ = Locational Marginal Price for LAP *i,* hour *t* ($/MWh)

$MCE_t$ = Marginal Cost of Energy component of the LMP for hour *t* ($/MWh)

$LAP\_MCC_{i,t}$ = MCC component of the LMP for LAP *i*, hour *t* ($/MWh)

$LAP\_MCL_{i,t}$ = MCL component of the LMP for LAP *i*, hour *t* ($/MWh)

$Supply\ MWh_{k,t}$ = Energy dispatch (MWh) for generation or import resource *k* in hour *t*

$LMP_{k,t}$ = Locational Marginal Price for generation or import resource *k* in hour *t* ($/MWh)

$MCC_{k,t}$ = MCC component of the LMP generation or import resource *k*, hour *t* ($/MWh)

$MCL_{k,t}$ = MCL component of the LMP for generation or import resource *k*, hour *t* ($/MWh)

For the analysis, we measure the Transaction Cost savings benefit to Market Participants as the cost difference between the TC with and without the Project.

$\Delta TC_t = TC_{t\,w} - TC_{t\,w/o}$

where,

$TC_w$ = the system's transaction cost with the Project ($),

$TC_{w/o}$ = the system's transaction cost without the Project ($)

The $\Delta TC_t$ for the AVCV Project and SOK Upgrade scenarios are -$16.4 Million and -$6.1 Million respectively:

| AVCV Project | Transaction Cost (TC) TC= [Load * LAP LMP]-[Gen * LMP] | | Delta |
|---|---|---|---|
| | B | S1 | |
| 2017 Total | $687,422,515 | $670,990,884 | -$16,431,631 |

| SOK Upgrade | Transaction Cost (TC) TC= [Load * LAP LMP]-[Gen * LMP] | | Delta |
|---|---|---|---|
| | B | S2 | |
| 2019 Total | $783,268,541 | $777,152,838 | -$6,115,704 |

### C.4.4 Congestion Revenue Calculation

The marginal congestion cost is also the Congestion Revenue (CR) paid to Congestion Revenue Rights (CRR) holders under the CAISO nodal market. Because the MCC is a component of the LMP, congestion costs are charged (or paid) to both suppliers and consumers in the market. Congestion Cost savings therefore are not exclusively a Consumer Benefit and will be included in the Societal Benefit cost.

The Congestion Cost is calculated each hour *t* as the sum of Congestion Revenue increase or decrease charged or paid to the suppliers at their nodal MCC and the Marginal Congestion Cost charged or paid to the load at the LAP_MCC. This Congestion Cost also reflects the revenue available to the market as a whole for funding CRRs.

$$CR_t = \left(\sum_i DemandMWh_{i,t} * LAP\_MCC_{i,t}\right) - \sum_k SupplyMWh_{k,t} * MCC_{k,t}$$

Once the CR is calculated for the scenarios, the Congestion Revenue can be quantified as the cost difference between the congestion cost (CR) with and without the Project.

$\Delta CR_t = CR_{t\,w} - CR_{t\,w/o}$

where,

$CR_w$ = Total congestion revenue with the Project ($)

$CR_{w/o}$ = Total congestion revenue without the Project ($)

The $\Delta CR_t$ for the AVCV Project and SOK Upgrade scenarios are -$20.7 Million and $1.07 Million respectively:

| AV Clearview Project | Congestion Revenue (CR) CR = [(-1)*Gen*MCC]+[Load*MCC] | | Delta |
|---|---|---|---|
| | B | S1 | |
| 2017 Total | $533,162,776 | $512,439,062 | -$20,723,715 |

| SOK Upgrade | Congestion Revenue (CR) CR = [(-1)*Gen*MCC]+[Load*MCC] | | Delta |
|---|---|---|---|
| | B | S2 | |
| 2019 Total | $676,764,096 | $677,838,280 | $1,074,184 |

## C.5 Calculation of the Societal Benefit

The additional transmission capacity provided by the project also provides benefit to the market as a whole. The net Societal Benefit is determined each hour *t* as the Consumer Benefit plus (a) Transmission Owners' benefits reflected in reduced congestion cost and (b) increased producers' or generators' surplus. Thus, the Societal Benefit is quantified as the cost savings and revenue surpluses to all CAISO Market Participants by summing the Consumer Benefits, Production Surplus increases and the Marginal Congestion Cost savings[43].

Societal Benefit = $BTL_t + \Delta PS_t - \Delta CR_t$

In addition to the Consumer Benefit (BTL) and Congestion Revenue savings (ΔCR) components described in Section 6.9.1, the increase in the Production Surplus is included in the Societal Benefits. Energy from lower cost generators (variable production cost) benefit the market as a whole; and if after netting revenues earned by Suppliers result in higher profits between sensitivities (with and without the project in-service), there is a Production Surplus *increase* which represents a benefit to suppliers. Finally, Congestion Cost savings (or Congestion Revenue decreases) are added because they represent cost savings to both consumers and suppliers in the market.

[43] Formulas use a negative sign convention (dollar amount) to reflect a congestion cost savings.

The hourly Societal Benefits are summed to get the net Societal Benefit for each study year. The total Societal Benefit for the AVCV Project and SOK Upgrade scenarios are $89.4 million and $28.9 million respectively:

| | Societal Benefit |
|---|---|
| AVCV Project | SB =(-1* Δ(LMC - MLS)) - ΔCR + ΔPS |
| | S1 |
| 2017 Total | $89,445,708 |

| | Societal Benefit |
|---|---|
| SOK Upgrade | SB =(-1* Δ(LMC - MLS)) - ΔCR + ΔPS |
| | S2 |
| 2019 Total | $28,861,217 |

The AV Clearview levelized annual Societal Benefit in 2017 dollars is $100.6 million with an NPV of Societal Benefit of $1.2 billion. In contrast, the calculated SOK levelized Societal benefit in 2017 dollars is $27.9 million with an NPV of $346.9 million.

### C.5.1 Production Surplus Calculation

The economic benefit to suppliers due to the Project is measured by comparing the Production Surplus between sensitivities. The Production Surplus is derived each hour *t* by taking the difference between revenues earned by generators at their LMPs and their Production Costs.

$$PS_t = PR_t - PC_t$$

The Production Surplus increase to the market with the Project in-service is calculated each hour *t* as

$$\Delta PS_t = PS_{t\ w} - PS_{t\ w/o}$$

where,

$PS_{t,w}$ = the Production Surplus in hour *t* with the Project ($)

$PS_{t,w/o}$ = the Production Surplus in hour *t* without the Project

The $\Delta PS_t$ for the AVCV Project and SOK Upgrade scenarios are -$62.5 Million and -$52.7 Million respectively:

| AVCV Project | Production Surplus (PS) PS = PR - PC | | Delta |
|---|---|---|---|
| | B | S1 | |
| 2017 Total | $5,908,189,700 | $5,845,642,735 | -$62,546,965 |

| SOK Upgrade | Production Surplus (PS) PS = PR - PC | | Delta |
|---|---|---|---|
| | B | S2 | |
| 2019 Total | $6,351,353,114 | $6,298,664,044 | -$52,689,070 |

### C.5.2 Production Cost Savings Calculation

The fundamental economic impact of a transmission upgrade is that it may make the system more efficient and thus lead to more efficient unit commitment and economic dispatch. The economic impact is measured by calculating the Suppliers' Production Cost savings which quantifies the reduction in total variable production cost to serve the load.[44] The net Production Cost savings in each hour *t* due to the Project is then calculated as:

$\Delta PC_t = PC_{t,w} - PC_{t,w/o}$.

where,

$PC_{t,w}$ = the system's total variable production cost in hour *t* with the Project ($)

$PC_{t,w/o}$ = the system's total variable production cost in hour *t* without the Project ($)

The $\Delta PC_t$ for the AVCV Project and SOK Upgrade scenarios are -$48 Million and -$31 Million respectively:

| AVCV Project | Production Cost (PC) PC = Supply MW * (Heat Rate + VOM) | | Delta |
|---|---|---|---|
| | B | S1 | |
| 2017 Total | $2,021,833,837 | $1,973,835,557 | -$47,998,279 |

[44] For this analysis, it is assumed that demand is inelastic, that is, the same Demand MWh are used in each case.

| SOK Upgrade | Production Cost (PC) PC = Supply MW * (Heat Rate + VOM) | | Delta |
|---|---|---|---|
| | B | S2 | |
| 2019 Total | $2,078,777,573 | $2,047,767,989 | -$31,009,584 |

The Production Cost is calculated for the system by summing the costs for all suppliers on the grid which is its energy dispatch in MWh multiplied by its fuel costs plus its variable operating costs. The system Production Cost is calculated for each hour *t* in the sensitivity year as follows:

$$PC_t = \sum_k (G_{k,t} * FC_k + VOM_k)$$

where,

$FC_k$ is supplier *k's* fuel cost at its average heat rate ($/MWh)[45]

$VOM_k$ is supplier *k's* variable operations and maintenance costs ($)

### C.5.3 Production Revenues Calculation

The Production Revenues calculate the payments to suppliers at the nodal LMPs for the various sensitivities. If overall revenues decrease with the AV Clearview project in place, it reflects an increased ability for other generation sources to serve the load center. Thus, with the increased capability to bring in more renewable energy, the LMPs and resulting revenues will decrease.

The Production Revenue is calculated for each hour *t* in the study period as follows:

$$PR_t = \sum_i (SupplyMWh_{k,t} * LMP_{k,t})$$

where,

$SupplyMWh_{k,t}$ = Energy dispatch (MWh) for generation or import resource *k* in hour *t*

$LMP_{k,t}$ = Locational Marginal Price for generation or import resource *k* in hour *t* ($/MWh)

The net Production Revenue decrease in each hour *t* due to the Project is then calculated as:

$\Delta PR_t = PR_{t,w} - PR_{t,w/o}$.

where,

$PR_{t,w}$ = the system's total payments to suppliers in hour *t* with the Project ($)

$PC_{t,w/o}$ = the system's total payments to suppliers in hour *t* without the Project ($)

The $\Delta PR_t$ for the AVCV Project and SOK Upgrade scenarios are -$110.5 Million and -$83.7 Million respectively:

[45] Unit-commitment is included in the simulation; the formula can be extended to include start-up costs and no-load costs.

| AVCV Project | Production Revenue (PR) | | Delta |
|---|---|---|---|
| | PR = Gen * LMP | | |
| | B | S1 | |
| 2017 Total | $7,930,023,536 | $7,819,478,292 | -$110,545,244 |

| SOK Upgrade | Production Revenue (PR) | | Delta |
|---|---|---|---|
| | PR = Gen * LMP | | |
| | B | S2 | |
| 2019 Total | $8,430,130,687 | $8,346,432,034 | -$83,698,654 |

## C.6 Normalization of Benefit Estimates

### C.6.1 Assumption in Calculating the AV Project Revenue

1. Operation date 2017
2. Revenue calculated for 2017
3. Economic life = 45 yrs.
4. Benefits escalation beyond 2017 = 1%
5. Benefit discount rate (weighted average capital cost) = 7.8% real
6. All revenue are expressed in $2017

**7. Assumption in Calculating the SCE Project Revenue**

1. Operation date 2019
2. Revenue calculated for 2019
3. Economic life = 45 yrs.
4. Benefits escalation beyond 2019 = 1%
5. Benefit discount rate (weighted average capital cost) = 7.8% real
6. All revenue are expressed in $2017

### C.6.2 Methodology

To determine which of the two projects to build, the CAISO, CPUC, or appropriate regulatory agency should compare the present value of benefits of each project. The project with the highest net benefit-to-cost ratio provides the greatest return on investment for ratepayers. This discussion considers benefits, but the normalization approach to costs is similar.

The present value of benefits (PV) for a project is defined as:

$$PV_{2017} = \sum_{t=1}^{53} \frac{Benefit_t}{(1+r)^t}$$

where

Benefit$_t$ = Consumer Benefit in year t, in 2017 dollars

Cost$_t$ = Levelized revenue requirement in year t, in 2017 dollars

r = Project's discount rate

Years 1, 2, 3, 4, …, 50,…53 respectively correspond to 2017, 2019, 2019, 2020, …, 2062.

For the AV Clearview project, the last three terms will be zero, since the life of the project is anticipated to run from 2017 through 2061. For the SOK Upgrade, the first two terms will be zero, since the life of the project runs from 2019 through 2063. Generally, for a project with a life between years *m* and *n* in the future, the PV today is

$$PV_{2017} = \sum_{t=m}^{n} \frac{Benefit_t}{(1+r)^t}.$$

The discount rate *r* is the developer's weighted average cost of capital in its most recent rate base.[46] We use a discount rate of 7.8% for each project.

### C.6.3 Calculations of Benefit Terms

Pursuant to CPUC direction,[47] benefit-to-cost ratios are to be calculated using both the California ratepayers' benefit and the societal benefit, calculated in the production cost model.

For the California ratepayers' production cost benefit in each year *t*, we use

$$Benefit_t = BTL_t,$$

the benefit to load calculated in the production cost models.

For the total production cost societal benefit in each year *t*, we use

$$\begin{aligned} Benefit_t &= SocietalBenefit_t \\ &= BTL_t + \Delta PS_t - \Delta CR_t \end{aligned},$$

the societal benefit calculated in the production cost models.

For tractability, each production cost model has been run for the full year (8760 hours) that it enters service; that is, 2017 for AV Clearview, and 2019 for South of Kramer. Future years are

46 CPUC Decision 06-11-018, Appendix A.

47 Ibid

modeled by escalating each project's benefits by 1 percent per year through the end of the project life.

We propose also to study benefits for year 2020 for both projects, once AV Clearview enters the CPUC's Certification of Public Convenience and Necessity process. Those 2020 benefits will then be used as the basis for the 1% annual benefits escalation in years beyond 2020. Benefits for years 2018 and 2019 for the AV Clearview project will be estimated by interpolation, using a compounded annual growth approach.

Annual benefits in both models are calculated in 2017 dollars. The annual 1% escalation is assumed to be net of inflation, so future benefits do not require further inflation adjustment.

Resource adequacy benefits are normalized in a similar manner.

# Appendix D – Reliability Assessment

## D.1 Reliability Assessment Cases and Kramer RPS Interconnection Results

The comparative reliability assessment calls for establishing 3 separate cases: a baseline case with no project; an AV Clearview Project case; and an SOK Upgrade case. The cases enable a comparative analysis of the present or existing topology to the AV Clearview Project, and to the alternative SOK Upgrade project (also known as the Coolwater-Lugo 230 kV Upgrade project) presently being considered and studied by the CAISO in the 2012/2013 Transmission Planning Process. Because of the proposed 2018 or later proposed operational date of the SOK Upgrade, it was necessary to select a study point in time that would have all three comparison alternatives available. Thus, all three cases built for the reliability assessment were based on the transmission topology and generation projects defined in the CAISO's 2021 Policy Driven base case.

The case was stressed by setting the modeled RPS generation in the Kramer region to the maximum on-line generation level of 392.6 MW (refer to Table D.1). This level of Kramer RPS generation establishes the Reliability baseline case ($B_{BL}$ case)[48].

The premise is to establish for reliability purposes a baseline of RPS generation in the Kramer region before expanding the renewable energy level in the AV Clearview and South of Kramer project cases. For each of the project cases, we begin with RPS generation modeled in the base case in the Kramer area, and adjust as follows:

- Increase Kramer-area RPS generation incrementally until the transmission system reaches its maximum allowable flow limits under contingency situations. Power flow analyses were performed for N-1, N-1-1 and N-2 scenarios. For the purposes of this economic benefit analysis, the maximum Kramer RPS generation capacity committed and still able to maintain allowable flow limits under the worst N-1 contingency are used to establish the total possible new RPS generation interconnected with either the AV Clearview Project or SOK Upgrade respectively (Table D.1).
- Make an adjustment for a remedial action scheme (RAS), which is a set of generation that is subject to curtailment in the event of a loss of the transmission line.

[48] The 392.6 MW of Kramer RPS generation modeled Reliability baseline case is significantly lower than CPUC's updated Commercial Interest renewable portfolio Kramer region capacity of 765 MW used in CAISO's 2012/2013 Transmission Plan as detailed in Table D.2.1.

The total Kramer RPS generation that results from above adjustments determines the total possible new generation capacity that can be interconnected with each project respectively. The table below compares the two projects' results in the above analysis.

**Table D.1 – Maximum RPS Generation Comparison**

| | AV Clearview | South of Kramer |
|---|---|---|
| **Kramer area generation** | 393 MW | 393 MW |
| **Additional N-1 Project Capability** | +841 MW | -94 MW |
| **RAS capacity (subject to curtailment)** | +136 MW | +136 MW |
| **Net transmission capability** | 1370 MW | 435 MW |

For the SOK Upgrade case, the study results show that the most limiting N-1 contingency is the loss of the Lugo-Jasper line which results in the Kramer-Lugo 230 kV lines reaching its maximum flow limit. Based on this contingency, the maximum additional Kramer RPS generation from the baseline case is -94 MW, meaning that the SOK Upgrade project can only support new RPS capacity of 299 MW at Kramer. This is below the modeled baseline Kramer RPS generation of 392.6 MW as well as the 765 MW modeled in CAISO's 2012/2013 Transmission Planning cases. In order for the SOK Upgrade to reach either of these RPS levels, it is assumed that there is automated generation dropping in the Kramer area or "RAS" that can be armed such that higher levels of generation can be interconnected and still meet N-1. For the purposes of this benefit study, we assume that there is at least 136 MW of RAS dropping for N-1. Thus, the total RPS generation that can be interconnected with SOK Upgrade and meet N-1 is 435 MW.

For the AV Clearview project case, the powerflow study results show that, under N-1, the maximum additional generation that can be added to Kramer with 1,000 MW flow on the HVDC is 840 MW. In this case, the N-1 contingency is the loss of Kramer-Yeager. The total RPS generation that can be interconnected with the AV Clearview Project is 1233 MW (392.6 + 841 MW). To compare on the same basis as the SOK Upgrade, the same RAS generation dropping of 136 MW is added and the total maximum allowable RPS generation that can be interconnected and meet N-1 is 1370 MW.

## D.2 Key Assumptions for the Reliability Cases

**Key Assumptions for the Reliability case (the $B_{BL}$ case) without projects**

1. Include CEC projected loads for 2021
2. Average Hydro and net Imports
3. Model all CAISO approved transmission projects except the South of Kramer Upgrade

4. Model renewable generation based on CAISO renewable Base Portfolio (2022 Commercial Interest portfolio as used by the CAISO in the 2012/2013 transmission planning process) with exception to the Kramer region or CREZ (tested region)
5. Include all existing generation and those projects that are under construction or that have completed all permitting requirements just prior to construction.

**Key Assumptions for the Reliability AV Clearview Project case (the $B_{AVC}$ case)**

1. Include CEC projected loads for 2021
2. Average Hydro and net Import
3. Model all CAISO approved transmission projects except the South of Kramer Upgrade; **include** AV Clearview Option 1 configuration options
4. Model incremental RPS generation in the Kramer area beyond that modeled in the baseline case using a surrogate generator, since specifics of project location and size are yet to be determined.

**Key Assumptions for the Reliability South of Kramer (SOK) case (the $B_{SOK}$ case)**

1. Include CAISO/CEC projected loads for 2021
2. Average Hydro and net Import
3. Model all CAISO approved transmission projects including the South of Kramer Upgrade 230 kV line (Coolwater to Jasper to Lugo, constructed for 500 kV and operated at 230 kV)
4. Model incremental RPS generation in the Kramer area beyond that modeled in the baseline case using a surrogate generator, since specifics of project location and size are yet to be determined.

In Appendix A and B, three configurations were identified establishing the specific base cases used for the comparison of the AV Clearview Project and the SOK Upgrade. The base line case was established beginning with the CAISO's 2021 Policy Driven base portfolio case posted on the CAISO's secure website. Further, the case was adjusted following review of the approved CAISO 2011/2012 Transmission Plan and the recently drafted 2012/2013 Transmission Plan, to coincide with the Commercial Interest renewable base portfolio (see Table D.1) and the 2022 Policy Driven base case.

### D.2.1 Renewable Generation

From the CAISO 2012/2013 transmission planning process, the Commercial Interest renewable energy portfolio was used to establish the level of new or additional renewable generation likely to be installed in the identified CREZ regions. This would be the target for how much transfer capability the two alternative projects would have to provide. Table D.2, taken from the CAISO's December 11-12, 2012 Transmission Planning Process Stakeholder Meeting presentation, displays the Commercial Interest renewable portfolio as used by the CAISO in their ongoing 2012/2013 transmission planning efforts. The Kramer CREZ value of 765 MW is identified as being directly affected by, or having a direct effect on, the analysis herein.

**Table D.2 – 33% RPS Commercial Interest Portfolio**[49]

| Zone | Biogas | Biomass | Geotherm | Hydro | Large Scal | Small Sola | Solar Ther | Wind | Grand Total |
|---|---|---|---|---|---|---|---|---|---|
| Alberta | | | | | | | | 450 | 450 |
| Arizona | | | | | 550 | | | | 550 |
| Baja | | | | | | | | 100 | 100 |
| Carrizo South | | | | | 900 | | | | 900 |
| Central Valley North | | 63 | | | 145 | | | | 208 |
| DG-NCA Muni | | | | | | 42 | | | 42 |
| DG-SCA Muni | | | | | | 112 | | | 112 |
| Distributed Solar - PG&E | | | | | | 1,005 | | | 1,005 |
| Distributed Solar - SCE | | | | | | 487 | | | 487 |
| Distributed Solar - SDGE | | | | | | 405 | | | 405 |
| El Dorado | | | | | 250 | | 500 | | 750 |
| Imperial | 15 | | 474 | | 1,356 | 30 | | 265 | 2,140 |
| Kramer | | | 64 | | 320 | 74 | 250 | 56 | 765 |
| Los Banos | | | | | 370 | | | | 370 |
| Merced | 5 | | | | 60 | | | | 65 |
| Mountain Pass | | | | | 300 | | 365 | | 665 |
| Nevada C | | | 142 | | | | | | 142 |
| NonCREZ | 104 | 7 | 15 | | 56 | 72 | | 3 | 256 |
| Northwest | | | | | | | | 330 | 330 |
| Palm Springs | | | | | | 16 | | 182 | 198 |
| Riverside East | | | | | 800 | 5 | 701 | | 1,506 |
| Round Mountain | | | | | | | | | 0 |
| San Bernardino - Lucerne | | | | | 45 | 19 | | 42 | 106 |
| San Diego South | | | | | | | | 384 | 384 |
| Solano | 3 | | | | 28 | | | 474 | 505 |
| Tehachapi | 10 | | | | 1,255 | 142 | | 1,988 | 3,395 |
| Westlands | | 49 | | | 1,293 | 158 | | | 1,500 |
| Grand Total | 136 | 119 | 695 | 0 | 7,728 | 2,567 | 1,816 | 4,274 | 17,335 |

To further emphasize the approach of comparing each project's ability to connect and transfer additional renewable energy, the level of queued generation per the CAISO's generation queue and SCE's WDAT generation queue is noted. The CAISO queue indicates the North of Lugo (from Control to Kramer) contains six (6) projects totaling 705 MW, and SCE's WDAT queue provides another approximately 218 MW for a total Kramer CREZ region generation increase of 926 MW (refer to queue excerpt Tables D.3 and D.4).

[49] http://www.caiso.com/Documents/Presentation2012-2013TransmissionPlanningProcessStakeholderMeetingDec11-12_2012.pdf

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## Table D.3 – CAISO Interconnection Queue for North of Lugo (Kramer CREZ)

| Queue Position | Type-1 | Fuel-1 | MW Total | Station or Transmission Line | Current On-line Date | Interconnection Agreement Status |
|---|---|---|---|---|---|---|
| 58 | ST | G | 62 | Control 115kV Substation | 2/1/2012 | Executed |
| 125 | ST | S | 250 | Coolwater-Kramer 230kv line | 12/1/2013 | Executed |
| 142 | ST | S | 80 | Kramer Substation 220kV | 4/1/2016 | In Progress |
| 695 | ST | G | 38 | Control Sub 115kV Bus | 12/31/2014 | |
| 909 | ST | S | 25 | Water Valley Substation 220kV | 2/11/2014 | |
| 942 | PV | S | 250 | Kramer Substation 220kV bus | 4/30/2016 | |

## Table D.4 – SCE WDAT Interconnection Queue for Kramer CREZ/Region

| Project Number | IA Executed (Y/N) | Technology | Facility Max Export Req(MW) | Facility County | Current Requested Facilities In-Service Date | Current Point of Interconnection | Current Point of Delivery |
|---|---|---|---|---|---|---|---|
| WDT883QFC | Yes | | 55 | Kern | 7/1/2013 | SCE Holgate Substation 115kV bus. | The ISO Grid at SCE's Kramer 115kV substation |
| WDT905 | No | PV | 50 | Kern | 1/10/2015 | 115kV gen-tie line into SCE's Holgate Substation | Kramer Substation 115 kV bus |
| WDT927 | No | PV | 35 | Kern | | SCE Holgate Substation switchyard at 115kV | |
| WDT936 | No | PV | 22 | San Bernardino | 12/10/2014 | Kramer - Rocket Test 115kV | |
| WDT946 | No | Co-Gen | 56.68 | San Bernandino | 3/15/2015 | Inyokern Substation, 115kV, Ridgecrest, CA | |

The South of Kramer Upgrade project is meant to support the transfer of renewable energy from the Kramer CREZ as well as the San Bernardino/Lucerne CREZ. According to the Commercial Interest base portfolio this energy level is 871 MW (765 MW + 106 MW). It is noted here that the San Bernardino/Lucerne (Jasper Switching Station) generation in the CAISO queue is ~ 420 MW (refer to Table D.5).

## Table D.5 – CAISO Interconnection Queue for San Bernardino/Lucerne CREZ

| Queue Position | Type-1 | Fuel-1 | MW Total | Station or Transmission Line | Current On-line Date | Interconnection Agreement Status |
|---|---|---|---|---|---|---|
| 68 | PV | S | 850 | Pisgah Sub 230 kV Bus | 3/31/2013 | Executed |
| 135 | WT | W | 60 | Lugo-Pisgah 230kV line (Jasper) | 12/31/2015 | Executed |
| 240 | ST | S | 400 | Pisgah Sub 230kV | 6/30/2014 | In Progress |
| 241 | ST | S | 400 | Pisgah Sub 230kV | 6/30/2015 | In Progress |
| 552 | PV | S | 60 | Lugo-Pisgah #1 230kV (Jasper) | 4/30/2013 | In Progress |
| 888 | PV | S | 100 | Jasper 220 kV | 10/15/2015 | |
| 892 | STH | S | 270 | Pisgah Substation 220kV bus | 12/31/2015 | |
| 897 | PV | S | 200 | Jasper Substation 220kV bus | 12/1/2016 | |

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## Table D.6 Base Generation Tables for Kramer – Coolwater Region

| Kramer - Coolwater - Jasper Area New Renewable Generation for Use in 2021 Heavy Summer Load Flow Cases | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | As Found in 2021 CAISO Base Case | | | Generation for Comparison Cases | | |
| | | | | | **Net** | **Base** | **SCE-South** | **230 kV** |
| | **Name** | **Unit ID** | **Pgen** | **Pmax** | **Available** | **Line** | **of Kramer** | **Clearview** |
| New Additions | | | | | | | | |
| | RPS10034 | Kramer | 76.5 | 80.0 | 3.5 | 80.0 | 80.0 | 80.0 |
| | RPS10064 | Kramer | 11.7 | 20.0 | 8.3 | 20.0 | 20.0 | 20.0 |
| | RPS10067 | Kramer | 11.9 | 20.0 | 8.1 | 20.0 | 20.0 | 20.0 |
| | RPS10198 | Lochhart | 125.0 | 125.0 | 0.0 | 125.0 | 125.0 | 125.0 |
| | RPS10380 | Lochhart | 125.0 | 150.0 | 25.0 | 125.0 | 125.0 | 125.0 |
| | RPS10070 | Victor | 11.3 | 11.3 | 0.0 | 11.3 | 11.3 | 11.3 |
| | RPS10071 | Victor | 11.3 | 11.3 | 0.0 | 11.3 | 11.3 | 11.3 |
| | | | 372.7 | 417.6 | 44.9 | 392.6 | 392.6 | 392.6 |
| Jasper Area | | | | | | | | |
| | RPS10016 | | 62.3 | 100.5 | 38.2 | 100.5 | 100.5 | 100.5 |
| | RPS10017 | | 62.3 | 100.5 | 38.2 | 100.5 | 100.5 | 100.5 |
| | RPS10025 | | 0.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 |
| | RPS10139 | | 36.9 | 60.0 | 23.1 | 60.0 | 60.0 | 60.0 |
| | | | 161.5 | 321.0 | 159.5 | 321.0 | 321.0 | 321.0 |
| | | | | | | | | |
| | Total New ("RPS10xxx") Gen | | 534.2 | 738.6 | 204.4 | 713.6 | 713.6 | 713.6 |
| | | | | | | | | |
| Total - All Gen in Kramer-Coolwater area | | | | 2,955.9 | | 2,758.9 | 2,758.9 | 2,758.9 |
| Total - All Gen in Kramer-Coolwater-Jasper area | | | | 3,276.9 | | 3,079.9 | 3,079.9 | 3,079.9 |

### D.2.2 Transmission Line Data

**Antelope Valley Clearview Project Reliability Analysis**
**Transmission Line Data**

Proposed Kramer - Yeager - Windhub Line Characteristics for 230 kV Construction

| | Per Unit on 100 MVA & Voltage Service | | | Ratings MVA) | | |
|---|---|---|---|---|---|---|
| | R | X | B | 1 (Norm) | 2 (Emerg) | Length (Mi) |
| Kramer - Yeager | 0.002800 | 0.015400 | 0.063000 | 1195 | 1315 | 21 |
| Yeager - Windhub | 0.002800 | 0.015400 | 0.063000 | 1195 | 1315 | 21 |
| **Total** | 0.005600 | 0.030800 | 0.126000 | 1195 | 1315 | 42 |

Proposed Kramer - Yeager - Windhub Line Characteristics for 500 kV Construction (Based on Lugo-Vincent Characterisitics)

| | Per Unit on 100 MVA & Voltage Service | | | Ratings MVA) | | |
|---|---|---|---|---|---|---|
| | R | X | B | 1 (Norm) | 2 (Emerg) | Length (Mi) |
| Kramer - Yeager | 0.000837 | 0.021402 | 0.085850 | 1195 | 1315 | 19 |
| Yeager - Windhub | 0.001013 | 0.025908 | 0.103924 | 1195 | 1315 | 23 |
| **Total** | 0.001850 | 0.047311 | 0.189774 | 1195 | 1315 | 42 |

## D.3 Reliability Analysis Discussion

The Antelope Valley Clearview Project, described in Appendix A of this report, provides for a robust and highly reliable transmission upgrade enabling significant renewable energy integration as well as providing positive operational attributes. The Project is presented herein as an alternative to a proposed transmission upgrade project referred to as the Coolwater-Lugo 230 kV transmission line, or interchangeably referred to as the South of Kramer Upgrade, described in Appendix B of this report.

The AV Clearview Project provides significant additional energy transfer capability from the Kramer-Coolwater area. It provides a transmission link between SCE's East of Lugo and Northern bulk systems increasing the reliability of both bulk systems by providing an outlet for energy flow with a reduced need to trip generation or load. The Project meets the needs as identified in the CPUC's Commercial Interest Portfolio to deliver 765 MW from the Kramer CREZ area could provide transmission access for an additional 605 MW, based on the study criteria described in D.1.

Additional key findings of the reliability analysis show that the AV Clearview project achieves the following:

1. Reduces south of Kramer flow,
2. Reduces south of Lugo flow,
3. Increases utilization of the lightly loaded Lugo – Vincent 500 kV lines
4. Increases utilization of the Tehachapi Regional Transmission Plan (TRTP) system

## D.4 Reliability Assessment Conclusions

- The AV Clearview Project provides significant additional outlet capability from the Kramer-Coolwater Area. The Project under all its variants at least or meets or exceeds the ability to deliver the 765 MW for the Kramer area as shown in Table D.1.

- The South of Kramer Project falls well short of meeting the outlet requirements for the Kramer areas noted in Table D.1.

- The existing system is sufficiently limited that it cannot deliver all of the generation in the Kramer area today, if it were all to operate fully under N-1 conditions. With the addition of new renewable generation already under construction or committed to construction, the ability of the existing system to serve as outlet for the area is even further diminished, and would require expansion of the already substantial Kramer RAS.

- The reliability analysis presented here deals only with the ability of the three alternatives to reliably deliver electricity from the Kramer-Coolwater region to the Los Angeles Basin area of Southern California Edison. In the course of testing the performance of the alternatives it was found that the ability of the Edison system to move the electricity south of Lugo and Vincent was at times problematic. For example, as shown in Note 12 of Section D.4.1, there is a more severe limit caused by conditions at Lugo Substation than by the performance of the South of Kramer Project alternative. It should be noted that there are no 230 kV lines going south from Lugo, so it is necessary to have sufficient 500/230 kV transformer capability at Lugo to reliably move electricity from the 230 kV system bringing it from the north and east up to the 500 kV system. The SOK Upgrade does nothing but exacerbate this long-term problem at Lugo while the AV Clearview Project helps relieve this particular problem in the timeframe studied. The AV Clearview Project is able to shift flows from the South of Lugo as well as Kramer area thus, and alleviate any future congestion in the South of Lugo and Kramer area.

- It was found necessary to add a fourth ($4^{th}$) 500/230 kV transformer at Vincent to be able to have pre-contingency flows south of Vincent for more than 500 MW from Tehachapi, Midway or Clearview above what was in the base case. The completion of the Tehachapi Renewable Transmission Project (TRTP) for some segments south of Vincent were not included in the CAISO load flow cases for either 2021 or 2022. While the 500 kV segment of the TRTP transmission from Vincent to Mira Loma was present, the 500 kV segment from Vincent to Rio Hondo and its associated 500/230 kV step-down transformer was not present. Therefore the inclusion of the fourth ($4^{th}$) 500/230 kV transformer at Vincent, *which was in the load flow case but not in service*, was used as a substitute or work-around for completion of the Tehachapi transmission.

## Appendix E – Valuation of Resource Adequacy Capacity

To estimate valuation of resource adequacy (RA) for the AV Clearview Project, we used the following assumptions:

1. Assume 250 MW of solar will be connected from the year the project comes online until 2019.
2. Assume 764 MW of solar will be connected in 2020, per the CAISO Transmission Plan, required to satisfy forecast energy use of 259,006 GWh for that year.
3. Beyond 2020, CAISO load will grow at a rate of 1.5 percent per year. The 33% Renewal Portfolio Standard will increase accordingly.
4. Solar photovoltaic projects will connect to the grid in the Kramer area to serve half of this increasing RPS obligation, at a solar capacity factor of 29 percent, until the capacity of the transmission project of 1,370 MW is reached.
5. Solar projects are assumed to be replaced and/or upgraded once their useful lives have been exhausted, so that solar generation will maintain full production capacity through the end of the transmission project's life.

The assumptions for RA valuation for the South of Kramer project are the same, except that the solar generation resources that can be connected are limited to a *maximum* of 435 MW.

The RA net qualifying capacity is calculated using the annual average of monthly qualifying capacities as represented in the *2013 CPUC Jurisdictional NQC List for RA Compliance*, posted on the CPUC website.[50] This annual average net qualifying capacity equates to 47.48% of installed capacity.

We apply a fixed RA value of $36 per kilowatt-year to the resultant NQC estimates to get estimated annual RA valuation streams for both projects. The final results are present values and levelized benefit streams for both projects, discounting to year 2016 as described above in Section C.6.3, using the weighted average capital costs for the respective projects, both equal to 7.8%.

[50] http://www.cpuc.ca.gov/NR/rdonlyres/83CB4D22-B52A-4EE1-B499-2119B14FF2E1/0/CPUCFinalNetQualifyingCapacityList2013.xlsx. Downloaded 1/29/13.

## Appendix F – HVDC Light Technology

In an AC transmission system, flows can be adjusted either by phase-shifting transformers, also known as phase angle regulators, or indirectly by adjusting generation. Both of these options require significant response times to adjust power flow. In an HVDC system, the operator can specify the volume of power to flow on the DC transmission line. In response to the operator adjustment, or "power order," power flow can instantly change from the neighboring AC system through the DC system. The electric grid will automatically adjust flow patterns on the AC to comply with the operator request without any change in the generation dispatch. This provides fast response and flexibility to the grid operator that would not otherwise be available, and facilitates management of grid issues such as congestion.

For example, suppose Path 26 flow is 3800 MW, and the AV Clearview HVDC scheduled flow is 550 MW at a particular moment. If the flow on Path 26 increases, say, to 4,100 MW, the operator will want to reduce the flow on Path 26 to 4,000 MW. By entering a power order at the Yeager HVDC converter station, the schedule flow will adjust from 550 MW to 650 MW on the DC transmission line. The AC flow on Path 26 to the HVDC line will drop and move to the HVDC line to comply with the new 650 MW schedule. The result is that flow on path 26 will instantly decrease by 100 MW.

Power can be controlled by changing the phase angle of the converter's AC voltage with respect to the filter bus voltage, whereas the reactive power can be controlled by changing the magnitude of the fundamental component of the converter's AC voltage with respect to the filter bus voltage. By controlling these two aspects of the converter's AC voltage, operation in all four "quadrants" is possible. This means that the converter can be operated in the middle of its reactive power range near unity power factor to maintain dynamic reactive power reserve for contingency voltage support similar to a static VAR compensator. It also means that the real power transfer can be changed rapidly without altering the reactive power exchange with the AC network or waiting for switching of shunt compensation.

The ability to independently control AC voltage magnitude and phase relative to the system voltage allows use of separate active and reactive power control loops for HVDC system regulation. The active power control loop can be set to control either the active power or the DC-side voltage. In a DC link, one station will then be selected to control the active power while the other must be set to control the DC-side voltage. The reactive power control loop can be set to control either the reactive power or the AC-side voltage. Either of these two modes can be selected independently at either end of the DC link.

Advantages of the AV Clearview HVDC design include the following:

- The AV Clearview Project utilizes a proven technology that can reliably integrate solar and wind resources and maximize the use of the transmission system. HVDC transmission using voltage-sourced converters (VSCs) with pulse-width modulation (PWM), commercially known as HVDC Light (or HVDC Plus, depending on the supplier), was introduced in the late 1990s. Since then, over a dozen HVDC Light projects around the world have been constructed.
- HVDC Light transmission can be beneficial to overall system performance. VSC technology can rapidly control both active and reactive power independently of one another.
- Reactive power can also be controlled at each terminal independent of the DC transmission voltage level. The dynamic support of the AC voltage at each converter terminal can improve the area's voltage stability and can increase the transfer capability out of the Kramer and Tehachapi areas.
- The phase angle at the Yeager HVDC station can be dynamically controlled by CAISO operators. This control capability gives flexibility to shift energy flow from one transmission path to another.
- The dynamic voltage support and improved voltage stability offered by VSC-based converters permit high power transfers without need for significant AC system reinforcement. VSCs do not suffer commutation failures, allowing fast recoveries from nearby AC faults.[51]

[51] HVDC Voltage Source Converter Manufacturers, See Appendix F

# Appendix G – Economic Development and Stimulus Benefits

Using the 7.8 percent weighted average cost of capital as a discount rate, a 2-year acceleration in payments to project staff and contractors increases the value of those payments by

$$(1 + 7.8\%)^2 - 1 = 16.2\%.$$

In its General Rate Case, SCE has requested approximately $12.7 billion,[52] or $2.5 billion per year, in capital infrastructure expenditure during the 5-year period between 2010 and 2014. SCE has claimed this will result in the following economic impact to the region and California[53]:

- Additional Jobs Supported Annually: 12,720 jobs
- Increase in Economic Value Added to State Annually = $2.8 billion spent by SCE; $4.3 billion accounting for second- and higher-order spending by job recipients
- Increased Contribution to State and Local Taxes = $1.215 billion

This equates to approximately $199,000 in direct SCE spending per job supported annually. SCE's economic multiplier of total economic value equates to 69% above and beyond direct spending. The effective state tax is 9.6% of direct spending.

Using a similar approach and equivalent metrics, the AV Clearview project will have the following effects during each year of construction, based on capital expenditure of $670 million, plus expenditure of $50 million for SCE system upgrades (total expenditure of $720 million, or $240 million per year over 3 years):

- Increase in economic value per year of $240 million in direct spending, or $406 million per year including indirect spending effects ($240 million x (1.69)). This results in $1.2 billion in total economic value over the 3-year construction period.
- 1,205 jobs supported annually ($240 million per year / $199,000 per job per year)
- Increased Contribution to State and Local Taxes = $23 million per year, or 69 million over 3 years ($240 million x 9.6% x 3 years)

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[52] SCE 2012 General Rate Case, Exhibit SCE-03, Testimony of Jim Kelly, TDBU, Vol. 1, Page 15. http://www3.sce.com/sscc/law/dis/dbattach3e.nsf/0/5C9571BD165E1788882577E300234A38/$FILE/S03V01.pdf. Retrieved 1/30/13.

[53] http://asset.sce.com/Documents/Customer%20Service%20-%20Rates/GRC_Jobs.pdf. Retrieved 1/30/13.