Arnold Schwarzenegger
Governor

STRATEGIC VALUE ANALYSIS FOR INTEGRATING RENEWABLE TECHNOLOGIES IN MEETING TARGET RENEWABLE PENETRATION

IN SUPPORT OF THE
2005 INTEGRATED ENERGY POLICY REPORT

CONSULTANT REPORT

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Abstract

This report discusses a methodology developed by the Public Interest Energy Research (PIER) of the California Energy Commission for strategically locating new renewable technologies close to transmission “hot spots” or congestion zones to improve transmission reliability while meeting the target renewable penetration levels. The methodology is called “Strategic Value Analysis.” A detailed state-wide transmission load flow was developed which locates potential transmission problem areas. By overlaying renewable energy resource locations onto a GIS map, locations can be found where renewable technologies would provide a benefit to the system by reducing transmission overloads. This report describes how each technology location was evaluated by its transmission benefit and its cost of energy. Two years, 2010 and 2017, were selected for analyses. This report describes how the methodology can be used to select renewable energy sites in meeting the 20 percent renewable energy penetration.

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Executive Summary

A Strategic Value Analysis (SVA) methodology, developed by the California Energy Commission PIER Renewables staff and Davis Power Consultants (DPC) team, was used to evaluate the economic feasibility of using in-state renewable resources to meet California's Renewable Portfolio Standard (RPS) targets, and to assess the impacts of deploying those resources on the state's electricity system.

Economic feasibility of renewable resources was evaluated by comparing the levelized cost of electricity generation (LCOE) values for renewable technologies against Market Price Referents (MPR) values that are currently being used in the RPS procurement bid process for 2010. Renewable technologies with LCOE values lower than the MPR values were deemed economically feasible. As MPR values represent a "floor" for renewable projects bidding into the RPS procurement process, this was considered a conservative approach to estimating the economic feasibility of renewable resources. For 2017, LCOE values were compared against estimated costs being developed under the California Public Utilities Commission for gas turbine combined cycle systems.

Potential impacts of deploying new renewable generation on the state's electricity system were assessed using a transmission reliability index metric developed by the DPC team called the Aggregated Megawatt Contingency Overload (AMWCO). The AWMCO metric is based on standard reliability measures from the North American Electric Reliability Council (NERC) "N-1" contingency approach. The "N-1" approach examines the impact of losing a generator, transmission line or substation on the electricity system reliability. Using an "N-1" approach, DPC was able to forecast potential overload situations in California's electricity system based on California Energy Commission forecasted load growth, and expected new generation and transmission capacity.

Baseline cases were developed for 2003, 2005, 2007, 2010 and 2017. DPC then simulated the impacts of deploying new renewable generation into the system at various locations and compared it against the baseline cases using the AMWCO metric. The AMWCO represents the sum of all transmission overloads across all single lines or the sum of the generator outage contingencies. That is, by using the AMWCO values resulting from deployment of renewable generators against the base cases, DPC was able to gauge the impacts of adding new renewable generation on the state's electricity system. Furthermore, DPC was able to optimize renewable generator deployment to obtain the highest transmission system reliability by locating renewables in a fashion to minimize the AMWCO values.

The DPC approach does not examine system impacts over the full course of the year. Data sets representing hour by hour profiles of renewable generators were not available during the course of this project. In addition, the extensiveness of information in the required data sets and the length of time associated with developing production cost simulations precluded the possibility of estimating

system impacts over a full year. Instead, system impacts were evaluated by DPC based on peak winter, spring and summer conditions. A peak summer condition was considered as a worst-case approach due to the sensitivity of the state's electricity system to summer peak load, and the inherent difficulty for intermittent generators, such as wind facilities, to match summer peak needs. Consequently, scenarios under which renewable generators could improve system reliability under summer peak conditions were generally considered to be applicable under other system conditions throughout the rest of the year. Full year analysis of the impacts is planned under the next stage of the analysis.

Under California's RPS, electricity suppliers are required to procure at least one percent of their electricity supplies from renewable resources each year to obtain an overall twenty percent renewable electricity mix by 2017. However, the California Energy Commission, the California Public Utilities Commission and the California Power Authority accelerated the 2017 target to 2010 in accordance with the 2003 Energy Action Plan. As a result, the economic feasibility and system impacts were investigated for the 2010 and 2017 timeframes.

Findings For 2010 Timeframe

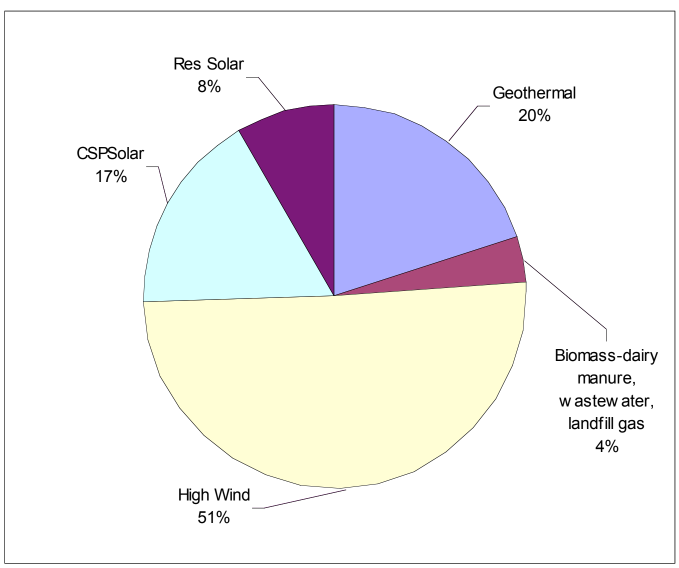
The twenty (20) percent RPS target corresponds to an estimated 28,969 gigawatt-hours (GWh) per year of new renewable energy. The corresponding generation capacity associated with the energy is dependent on the resource type (base, intermediate, and peaking). The results in this report indicate that in-state renewable resources that require little increase in new transmission lines (see Appendix B for a description of new transmission lines included in the 2010 analysis) can provide approximately eighty-five (85) percent (24,575,216 MWh) of the electricity needs required by the RPS target, based on the SVA approach. The remaining fifteen (15) percent of the required electricity can be developed from out-of-state renewable resources and/or from in-state renewable resources that will need new transmission capacity. The table below shows the distribution of the renewable energy resources. The average capacity factor of new renewable generation is 46.5 percent.

2010 Renewable Technology Penetration by Resource Type

Technology	MW	Mix %	C.F. %	Energy	Mix %
Geothermal	1,214	20%	90.0%	9,571,176	39%
Biomass-dairy manure, wastewater, landfill gas	228	4%	90.0%	1,797,552	7%
High Wind	3,041	50%	37.0%	9,856,489	40%
CSP Solar	1,046	17%	27.0%	2,473,999	10%
Res Solar	500	8%	20.0%	876,000	4%
Total	6,029	100%	46.5%	24,575,216	100%
20% Requirement			85%	28,969,000	
Net Short				(4,393,784)	

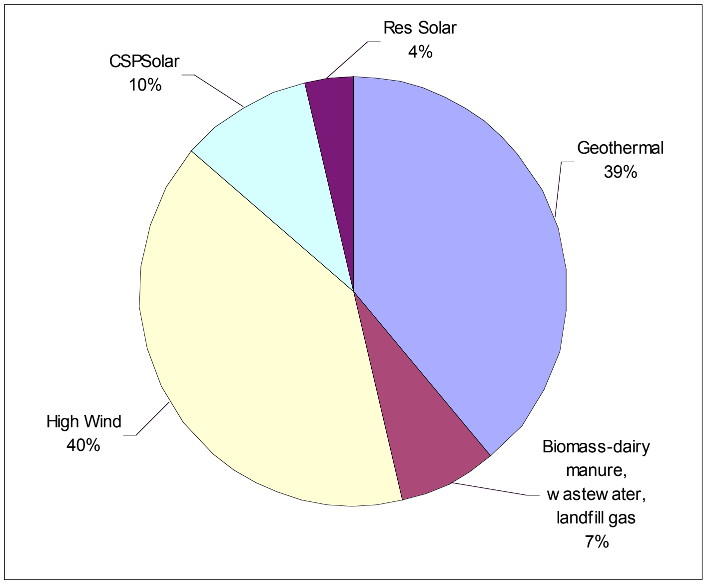
The figure below graphically displays the distribution of the renewable capacity mix. The high wind renewable resources are fifty-one (51) percent of the total resource capacity added by 2010. Geothermal resources comprise twenty (20) percent of the capacity mix. The remaining twenty-nine (29) percent is distributed among the remaining renewable resources.

2010 Renewable Technology Capacity Distribution



The figure below graphically displays the energy distribution for the 2010 renewable technologies installed. High wind resource comprised fifty-one (51) percent of the capacity and forty (40) percent of the energy. Geothermal comprised twenty (20) percent of the capacity and thirty-nine (39) percent of the energy.

2010 Renewable Technology Energy Distribution



In both the 2010 and 2017 baseline cases, power flow analyses identified overloading of specific transmission lines requiring upgrades to ensure power could flow through the grid. The necessary upgrades were made to the baseline cases and costs of the upgrades were identified. These transmission upgrades represent changes needed to allow power flow from any generation source; not just from renewable resources.

After the baseline cases were established, renewable resources were added separately and then added as a blend to examine the upper limit of renewables that could be added to address the RPS targets. In 2010 after the installation of 5,949 MW of renewable technology, transmission load flow results indicated that three transmission lines were overloaded. After upgrading these lines, we were able to strategically add 5,949 MW of new renewable technology that produced a transmission impact ratio of -0.224. That means, for every 1 MW of new renewable technology added, we were able to improve the transmission system reliability index by 0.224 MW.

In an attempt to improve the transmission impact ratio, we analyzed the transmission overloads that were driving the impact ratio low. Ten transmission lines were responsible for 1,088 MW or 67 percent of all increases in contingency overloads from the base case to the integrated case.

As a sensitivity case, we upgraded all ten lines and completed another contingency load flow. The AMWCO for the renewable case decreased from 12,024 to 9,402; and changed the impact ratio from -0.224 to -0.685. These overloads were substantially reduced in the 2017 renewable load flow case with the addition of more distributed generation renewables. In essence, overload conditions in 2010 were caused by the high level of new renewable generation sharing transmission lines already serving load centers. However in 2017, these lines became unloaded as we added more local, distributed generation that could help meets demand closer to load. However, additional analysis needs to be completed to fully understand the cause of the low impact ratio. Some of the causes could be attributed to:

- No re-dispatch of the existing in-area resources to optimize resources
- Continued high import levels from out-of-state resources
- Location of RMR units may need to be moved to other units
- Transmission system is operating at or near maximum capacity

Findings For 2017 Timeframe

In the 2017 base case, there were twelve (12) transmission lines that needed to be upgraded. When we added the 2,729 MW of renewable technologies, we had fifteen (15) overloaded lines in the modified renewable base case. These were upgraded before running any contingency analysis.

When we completed the contingency analysis, the transmission impact ratio was -0.982. For every 1 MW of new renewable technology added, we were able to reduce the transmission system reliability index by 0.982. However, there were thirteen (13) overloaded lines in the contingency case.

We performed a preliminary assessment on how the impact ratio could be improved by focusing on individual transmission lines that experienced increased contingency MW overloads after the renewable integration. If all of these lines were upgraded and a new load flow case completed, the new AMWCO would be 16,765 as compared to the base AMWCO of 27,803 MW. The new impact ratio would be negative a -1.25.

Similar to 2010, there needs to be additional load flow analysis to determine the cause of the low impact ratios and the value of upgrading these lines. If there are only a few lines that impact the impact ratio, then upgrading the lines would be more likely. If the impact ratio is distributed over numerous lines, then more detailed analysis needs to be completed to determine if adjustments to RAS, RMR or plant retirements are needed. Some of the causes could be attributed to:

- No re-dispatch of the existing in-area resources to optimize resources
- Continued high import levels from out-of-state resources

- Location of RMR units may need to be moved to other units
- Transmission system is operating at or near maximum capacity

The twenty (20) percent incremental (i.e., energy needs above that provided by 2010) renewable target penetration by 2017 was projected to be 9,346,784 MWh of energy. This included the energy not met in 2010. The corresponding capacity associated with the energy is dependent on the resource type (base, intermediate, and peaking). The average capacity factor was 48.7 percent. The SVA approach considers both the transmission benefits and the cost of energy of the renewable technology. The table below shows the incremental renewable technologies projected to be installed to meet the full 20 percent.

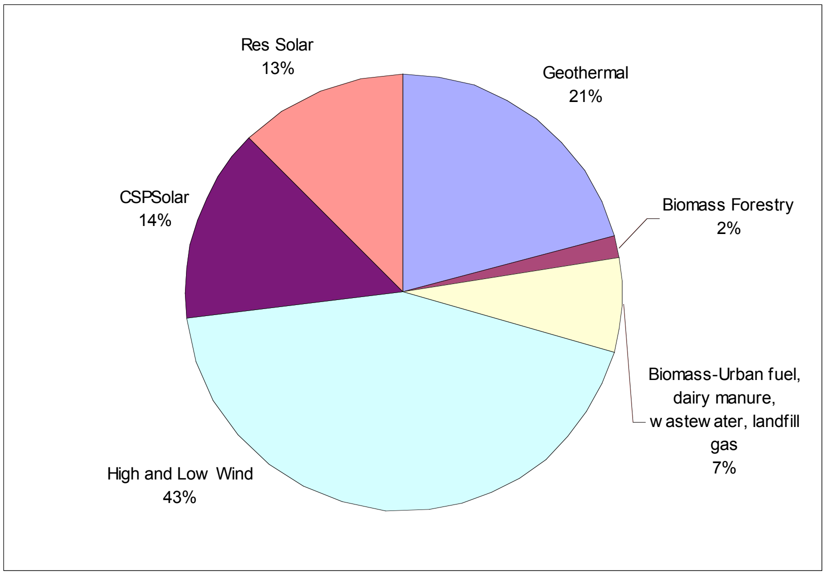
2017 Incremental Renewable Energy by Resource Type

Location	Technology	utility	MW	C.F. %	Energy
Salton Sea	Geothermal	Imperial	400	90.0%	3,153,600
Geysers	Geothermal	PG&E	-	90.0%	-
Niland	Geothermal	Imperial	42	90.0%	331,128
Fire Threat	Biomass	State wide	132	85.0%	982,872
State wide	WWTP, LFGTE, Dairy, Urban fuels	State wide	320	90.0%	2,522,880
Tehachapi	High Wind	SCE	300	37.0%	972,360
Contra Costa	Low Wind	PG&E	28	25.0%	61,320
Siskiyou	Low Wind	PacifiCorp	41	25.0%	89,790
Ventura	Low Wind	SCE	50	25.0%	109,500
Yolo	Low Wind	PG&E	3	25.0%	6,570
San Diego	CSP Solar	San Diego	35	27.0%	82,782
Imperial	CSP Solar	Imperial	66	27.0%	156,103
All	Res Solar	State wide	500	20.0%	876,000
Total			1,917	55.6%	9,344,905
20% Requirement					4,953,000
2010 Carryover					4,393,784
Net					(1,878)

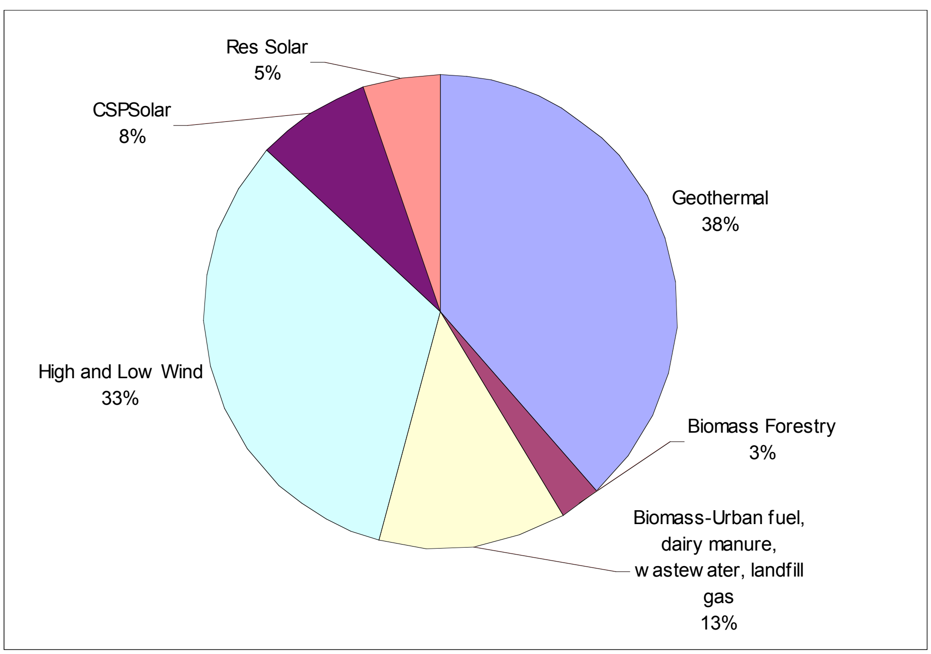
By the end of 2017, the total 20 percent penetration was projected to be 33,922 GWh. Renewable development approaches under the SVA indicate this target can be achieved by 2017. Under the SVA approach, we installed a total of 7,946 MW which produced 33,920 GWh. This is slightly lower than the target if we maintain the designed capacity factor. The average capacity factor of the installed renewable generation was 48.7 percent. The table below shows the total installed renewable resource mix to meet the 2017 penetration.

Technology	MW	Mix %	C.F. %	Energy	Mix %
Geothermal	1,656	21%	90.0%	13,055,904	38%
Biomass Forestry	132	2%	85.0%	982,872	3%
Biomass-Urban fuels, dairy manure, wastewater, landfill gas	548	7%	90.0%	4,320,432	13%
High Wind	3,341	42%	37.0%	10,828,849	32%
Low Wind	122	2%	25.0%	267,180	1%
CSP Solar	1,147	14%	27.0%	2,712,884	8%
Res Solar	1,000	13%	20.0%	1,752,000	5%
Total	7,946	100%	48.7%	33,920,122	100%
20% Requirement				33,922,000	
Net				(1,878)	

The pie chart below that shows the resulting capacity mix of renewable technologies by 2017. From this analysis, forty-three (43) percent of the capacity is expected to come from high and low wind speed turbines due to their relatively low LCOE values. The other renewables are approximately equal in percentages.



The energy distribution pie chart below shows a different distribution of the energy from the renewable resources. Geothermal resources will contribute the highest percentage at thirty-eight (38) percent and high/low wind will contribute thirty-three (33) percent.



A more interesting observation is that seventy (70) percent of the capacity and forty-six (46) percent of the energy will be from intermittent resources such as wind and solar. As we continue to refine the renewable resource mix, it will be interesting to observe what the final mix could be and the impact that intermittent resources could have on transmission operations.

After completing the integration analysis, the following conclusions have been developed:

- The SVA approach indicates that California can fully meet a twenty percent by 2017 RPS goal and meet approximately 85% of a twenty percent by 2010 RPS goal with in-state renewables that are cost competitive when compared to 2004 MPR values or estimated costs of gas turbine combined cycle systems for 2017. In addition, deployment of these in-state renewables can be accomplished in a way that results in a net improvement in transmission system reliability with little new significant transmission lines.
- The SVA approach can help in evaluating the costs and grid impacts of bringing renewables into California's electricity system while addressing RPS targets
- The SVA process can act as a transparent and common methodology for renewable energy developers, utilities and affected agencies to evaluate magnitudes, locations and impacts or benefits of renewables being used to meet RPS goals
- SVA can provide information that may be helpful to renewable developers and utilities involved in assessing "least-cost, best-fit" approaches to selecting renewables to meet RPS goals
- The SVA methodology could benefit from perspectives, datasets and information being developed by the Tehachapi and Imperial study groups
- The SVA approach can possibly be a useful tool in identifying potential transmission congestion and problems that may occur as renewable penetration increases, and in finding ways to help reduce or mitigate those problems
- The SVA methodology could benefit from having refined transmission cost values that reflect the full cost of transmission development for such items as right-of-way, transmission reconductoring, permitting and environmental factors, and improved transmission tower costs by type and conductor size.

We realize that the utilities are anticipating meeting the full 20 percent by 2010 under approaches separate from the proposed SVA methodology. They may be purchasing out-of-state resources or be examining other in-state sites not considered in our analysis. However, as the utilities continue with the RPS process, the SVA methodology could be useful to either the utilities and/or developers in acting as a common and transparent approach that will enable additional communication between the various parties and possibly help accelerate consensus on ways to achieve RPS goals. If such an approach begins, we could update the tables showing how the penetration can be met.

The keys to developing a renewable plan are:

- Utility and developer participation.
- Knowledge and understanding on the resource mix requirements.
- Supported transmission data bases.

Based on the analytical and the conclusions listed above, the following recommendations are suggested:

- The California Public Utilities Commission (CPUC) and Energy Commission should consider incorporating the transmission benefit ratios into the RPS process to encourage development of renewables at strategic locations
- The SVA analysis should be expanded to include seasonal transmission power flows. Many transmission problems could occur during the non-summer peak periods. Consequently, the analyses should update the load flow data sets under spring and winter conditions
- The SVA process should be more user-friendly and integrated into one process that incorporates GIS, power flow modeling and economic analysis.
- The Energy Commission and CPUC should examine ways to include and protect confidential data needed in the SVA process.
- Incorporating production costing into the SVA process is very important and should be considered as a next step in enhancing the SVA as an evaluation tool
- The Energy Commission divisions associated with transmission siting and planning, renewable energy development and the electricity analysis should consider adopting common naming conventions for generation and transmission sources, using common datasets and a common approach like the SVA process in evaluating how RPS goals tie into overall electricity generation and transmission planning activities.
- The CPUC and Energy Commission should consider ways of adopting the SVA model for analysis related to state policy-making on the RPS
- The Energy Commission should compare estimated cost and transmission impacts resulting from the SVA model to the impact of renewable energy projects used to meet the California RPS to assess the accuracy of the SVA approach.

Introduction

The California Energy Commission's Public Interest Energy Research (PIER) has been investigating a method for selecting strategic locations for renewables that could reduce transmission congestion while addressing the state's Renewable Portfolio Standard (RPS) goals. This methodology is referred to as the "Strategic Value Assessment" or SVA. SVA provides the vision or roadmap for integrating cost-competitive renewables into the California grid from 2005 through 2017. The principle components of the roadmap include:

- Assess the renewable technology resource potential for meeting RPS goals
- Identify key focus areas for additional studies
- Evaluate economics and timeframe
- Evaluate points of interconnection for high strategic value to the grid
- Consider solutions with significant environmental, economic and other non-energy benefits to the state
- Provide solutions that can defer transmission upgrades and help prioritize transmission needs
- Prioritize renewable implementation and transmission infrastructure needs

This report describes the approach and conclusions of the SVA to assist in meeting the California renewable penetration targets while improving transmission reliability.

Conclusions

After completing the integration analysis, the following conclusions have been developed:

- The SVA approach indicates that California can fully meet a twenty percent by 2017 RPS goal and meet approximately 85% of a twenty percent by 2010 RPS goal with in-state renewables that are cost competitive when compared to 2004 MPR values or estimated costs of gas turbine combined cycle systems for 2017. In addition, deployment of these in-state renewables can be accomplished in a way that results in a net improvement in transmission system reliability with little new significant transmission lines.
- The SVA approach can help in evaluating the costs and grid impacts of bringing renewables into California's electricity system while addressing RPS targets
- The SVA process can act as a transparent and common methodology for renewable energy developers, utilities and affected agencies to evaluate magnitudes, locations and impacts or benefits of renewables being used to meet RPS goals
- SVA can provide information that may be helpful to renewable developers and utilities involved in assessing "least-cost, best-fit" approaches to selecting renewables to meet RPS goals

- The SVA methodology could benefit from perspectives, datasets and information being developed by the Tehachapi and Imperial study groups
- The SVA approach can possibly be a useful tool in identifying potential transmission congestion and problems that may occur as renewable penetration increases, and in finding ways to help reduce or mitigate those problems
- The SVA methodology could benefit from having refined transmission cost values that reflect the full cost of transmission development for such items as right-of-way, transmission reconductoring, permitting and environmental factors, and improved transmission tower costs by type and conductor size.

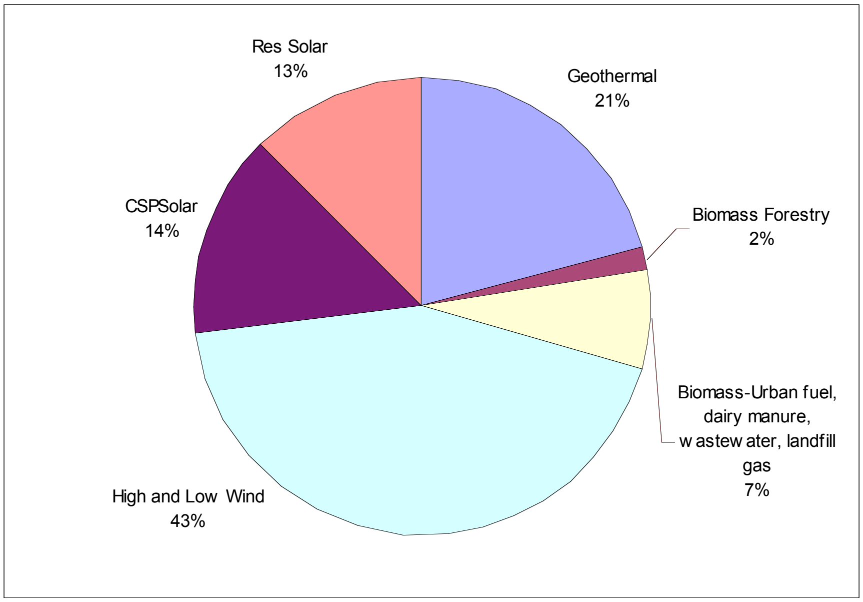
We realize that the utilities are anticipating meeting the full 20 percent by 2010 under approaches separate from the proposed SVA methodology. They may be purchasing out-of-state resources or be examining other in-state sites not considered in our analysis. However, as the utilities continue with the RPS process, the SVA methodology could be useful to either the utilities and/or developers in acting as a common and transparent approach that will enable additional communication between the various parties and possibly help accelerate consensus on ways to achieve RPS goals. If such an approach begins, we could update the tables showing how the penetration can be met.

The keys to developing a renewable plan are:

- Utility and developer participation.
- Knowledge and understanding on the resource mix requirements.
- Supported transmission data bases.

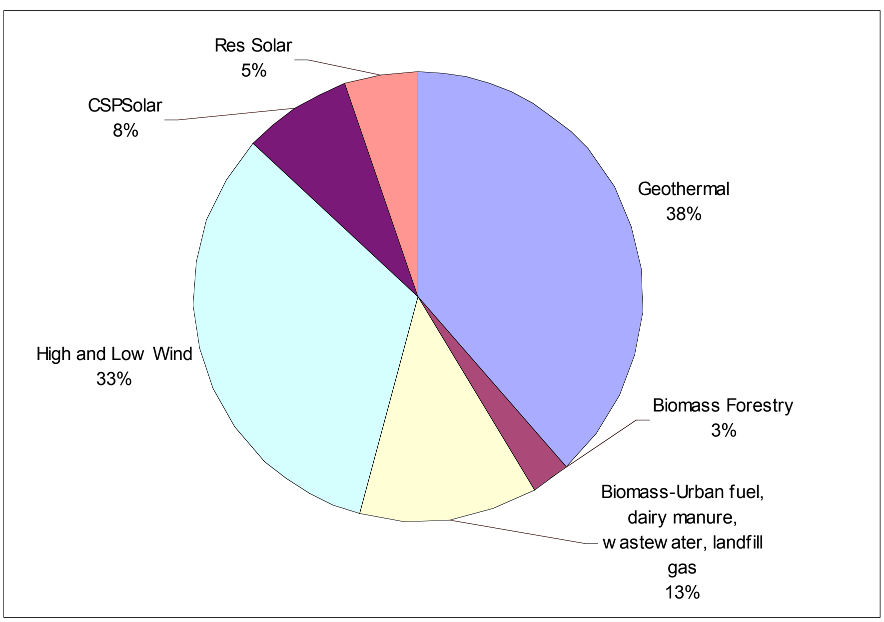
Figure 1 is a pie chart that shows the resulting capacity mix of renewable technologies by 2017. From this analysis, forty-three (43) percent of the capacity will be from high and low wind speed turbines. The other renewables are approximately equal in percentages.

Figure 1: 2017 Renewable Energy Mix (Capacity)



The energy distribution pie chart (Figure 2) shows a different distribution of the energy from the renewable resources. Geothermal resources will contribute the highest percentage at Thirty-eight (38) percent and high/low wind will contribute thirty-three (33) percent.

Figure 2: 2017 Renewable Technology Mix (Energy)



A more interesting observation is that seventy (70) percent of the capacity and forty-six (46) percent of the energy will be from intermittent resources such as wind and solar. As we continue to refine the renewable resource mix, it will be interesting to observe what the final mix could be and the impact that intermittent resources could have on transmission operations.

Recommendations

Based on the analysis and the conclusions listed above, the following recommendations are suggested:

- The California Public Utilities Commission (CPUC) and Energy Commission should consider incorporating the transmission benefit ratios into the RPS process to encourage development of renewables at strategic locations
- The SVA analysis should be expanded to include seasonal transmission power flows. Many transmission problems could occur during the non-summer peak periods. Consequently, the analyses should update the load flow data sets under spring and winter conditions
- The SVA process should be more user-friendly and integrated into one process that incorporates GIS, power flow modeling and economic analysis.
- The Energy Commission and CPUC should examine ways to include and protect confidential data needed in the SVA process.
- Incorporating production costing into the SVA process is very important and should be considered as a next step in enhancing the SVA as an evaluation tool
- The Energy Commission divisions associated with transmission siting and planning, renewable energy development and the electricity analysis should consider adopting common naming conventions for generation and transmission sources, using common datasets and a common approach like the SVA process in evaluating how RPS goals tie into overall electricity generation and transmission planning activities.
- The CPUC and Energy Commission should consider ways of adopting the SVA model for analysis related to state policy-making on the RPS
- The Energy Commission should compare estimated cost and transmission impacts resulting from the SVA model to the impact of renewable energy projects used to meet the California RPS to assess the accuracy of the SVA approach.

Discussion

Background

Davis Power Consultants (DPC) team is comprised of staff from Davis Power Consultants, PowerWorld Corporation and Anthony Engineering. Reference to DPC in this report is the three consulting companies listed above. DPC was engaged by the Energy Commission to identify possible areas within California's transmission and distribution system where adequacy or reliability problems (termed "hot spots") might emerge. Power flow analyses were used to identify the "hot spots" under summer peak conditions for 2005, 2007, 2010 and 2017. Appendix A is a report prepared for PIER that describes the development of the 2007 base case. 2007 has been included since the 2010 and 2017 data sets were developed from the 2007 base case. Appendix B describes the development of the 2010 and 2017 transmission load flow data sets. We incorporated suggested modifications to generation and transmission by the Energy Commission Systems Assessment and Facilities Siting Division to include updated retirements and additions. We also incorporated information from the CA ISO on RMR units and generator retirements.

DPC obtained transmission load flow data sets from PG&E, SCE and SDG&E for 2003, 2005 and 2007. Corrections were made to the data sets to be consistent with production costing results from the Electricity Analysis Office. Projected generator additions and retirements that were provided by the Systems Assessment and Facilities Siting Division were also incorporated. The 2007 data set was expanded out to 2010 and 2017 using the production costing results from the Electricity Analysis Office.

DPC developed a metric called the Weighted Transmission Loading Relief Factor (WTLR) as a single indicator of the effectiveness for overload mitigation at each bus (substation). The WTLR represents the expected contingency megawatt overload reduction if 1 MW of new generation is injected at that bus. For example, a bus with a WTLR of 4 means that for every 1 MW of installed generation there will be a corresponding 4 MW reduction in the contingency overload. Since there are transmission overloads among transmission lines rated from 69 kV to 500 kV and in different utility control areas, DPC developed a methodology that compares the transmission benefits of locating different power plants at different locations on an unbiased basis. There are DPC task reports that describe the methodology available through PIER.

In basic terms, the DPC methodology first computes the sum of all transmission overloads across all single line or generator outage contingencies. The result is called the Aggregated MegaWatt Contingency Overload (AMWCO), which is a measure of system reliability. The methodology then uses the number of overload occurrences, nominal voltage of the element and the average percent overload over all of the occurrences to calculate the WTLR at each bus (substation).

The DPC methodology is an independent means of prioritizing locations for new power plants (conventional or renewable). The approach allows a comparison in the reduction of the AMWCO for generation situated at different WTLR locations. For example, assume a substation AMWCO is 10,000 MW and there are two possible projects that can reduce the AMWCO. One project provides power at 500 kV with a WTLR of 2 that reduces the AMWCO down to 9,500. The second project provides power at 115 kV with a WTLR of 4 that reduces the AMWCO to 9,000. Based on the DPC approach, the 115 kV site would be selected as the priority location due to its greater reduction in the AMWCO.

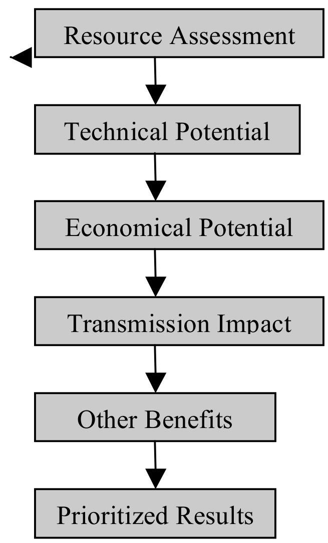
An AMWCO is a metric of the reliability of the transmission grid. It is not to be confused with the amount of generation or transmission needed to be added to the system. Used in combination, the WTLR indicates the effectiveness of installing new generation at a bus while the change in AMWCO indicates the overall improvement that the new generator has on the reliability of the entire system.

When a base year contingency analysis is performed, an AMWCO value can be calculated. This is the base value from which all renewable technologies can be compared for a given year. For each renewable technology simulation completed, another AMWCO is calculated. When the difference between the two AMWCO values are divided by the capacity of the renewable technology being evaluated, the resulting value is the transmission impact ratio. A negative impact ratio indicates that the installation of the renewable technology at the evaluated connection point resulted in an improvement in transmission reliability. A positive value results in a decrease in transmission reliability.

The general concept to the SVA approach is shown in Figure 3, below. The Energy Commission and the Fire and Resources Assessment Program of the California Department of Forestry (CDF/FRAP) completed a resource assessment for each of the renewable technologies. From the resource assessment, they developed gross, technical and economic potentials for each technology.

DPC developed a detailed state-wide transmission load flow and associated maps that highlighted the location of transmission “hot spots” or transmission congestion areas. These hot spot locations were transferred to an Excel spreadsheet and sent to CDF/FRAP. CDF/FRAP then prepared an overlay map that displayed the transmission hot spots and the economic potential of each renewable technology. This data was also prepared into an Excel spreadsheet.

Figure 3: SVA Approach



The locations on the maps were then analyzed in the transmission load flow model to determine which renewable resource provided transmission benefits to the system. If the renewable technology improved transmission reliability and reduced transmission overloads, then it was considered for further analysis. If the installation of the renewable resource further decreased transmission reliability, then it was not considered for any further analysis.

Since the renewable resource would not be exactly located at the transmission hot spot, transmission upgrades or new transmission lines may need to be constructed. DPC estimated these potential transmission costs and transferred the costs to the Energy Commission. The Energy Commission then calculated the Levelized Cost of Energy (LCOE) with and without transmission costs. This information was transferred back to DPC.

Matrix of Renewable Resource Alternatives

Table 1 lists the renewable technologies evaluated in this report. The table lists the utility service area, renewable type, location and transmission impact ratios. The 2010 and 2017 LCOE are the levelized cost of energy in cents/kWh in current year dollars. The costs do not include transmission capital costs. The LCOE were developed by the PIER staff. The reference LCOE to be used to determine if the renewable technology location could be a cost effective and potentially provide lower costs that the reference resource. For this study, we used the CPUC Market Price Reference for 2010 and the CPUC combined cycle for 2017.

The information in Table 1 will be used to select which renewable technology and associated location could be available for 2010 and 2017. If the Impact ratio is positive for either year, the resource is eliminated. If the renewable location had a LCOE that was higher than the referent energy price, it was eliminated from further consideration. In the following sections, the selection process for each technology type is described. This list is not to be considered the full list of potential renewable locations but a representative list. The utilities have specific locations as well developers of in-state and out-of-state resources. Imagine the benefits if a full matrix of resources could be developed from which utilities, developers and agencies could select strategic renewable locations.

Table 1: Available Renewable Technology Alternatives

Utility	Renewable	Location	MW	2010 Impact Ratio	2010 LCOE (cents/kWh)	2010 Market Price Referent (cents/kWh)	2017 Impact Ratio	2017 LCOE (cents/k Wh)	2017 CPUC CC (cents/k Wh)
State wide	Biomass Dairy	Diary Manure	38	-4.5	3.76	6.05	-4.5	2.14	9.15
PG&E	Biomass Forestry	RDGE CBN	59	-3	6.49	6.05	-3	5.52	9.15
PG&E	Biomass Forestry	KEKAWAKA	43	-3	7.07	6.05	-3	6.08	9.15
PG&E	Biomass Forestry	HGHLNDJ2	18	-3	10.00	6.05	-3	8.95	9.15
PG&E	Biomass Forestry	WILLITS	35	-3	7.55	6.05	-3	6.55	9.15
PG&E	Biomass Forestry	MIRABEL	18	-3	10.00	6.05	-3	8.95	9.15
PG&E	Biomass Forestry	TRINITY	26	-3	8.45	6.05	-3	7.43	9.15
PG&E	Biomass Forestry	CEDR CRK	39	-3	7.28	6.05	-3	6.29	9.15
PG&E	Biomass Forestry	TYLER	11	-3	13.21	6.05	-3	12.1	9.15
PG&E	Biomass Forestry	BIG MDWS	32	-3	7.79	6.05	-3	6.79	9.15
PG&E	Biomass Forestry	GRSS VLY	40	-3	7.22	6.05	-3	6.23	9.15
PG&E	Biomass Forestry	CH.STNJT	21	-3	9.28	6.05	-3	8.24	9.15
PG&E	Biomass Forestry	JONESFRK	25	-3	8.59	6.05	-3	7.57	9.15
PG&E	Biomass Forestry	PARADISE	26	-3	8.45	6.05	-3	7.43	9.15
State wide	Biomass Landfill Gas	Landfill Gas	318	-4.5	3.23	6.05	-4.5	2.98	9.15
State wide	Biomass WWT	Wastewater Treatment	59	-4.5	4.19	6.05	-4.5	3.79	9.15
State wide	Biomass Urban fuels	Urban Fuel	497	N/A	N/A	6.05	-4.5	6.02	9.15
Imperial	CSP Solar	Imperial	66	-3.2	6.00	6.05	-3.2	6	9.15
PG&E	CSP Solar	Plumas	0	-3	6.00	6.05	-3	6	9.15
SCE	CSP Solar	Riverside	599	-3.2	6.00	6.05	-3.2	6	9.15
SCE	CSP Solar	San Bernardino	447	-1.7	6.00	6.05	-1.7	6	9.15
SDG&E	CSP Solar	San Diego	35	-1.8	6.00	6.05	-1.8	6	9.15
Imperial	Geothermal	Superstition Mountain	10	-15.83	6.48	6.05	-15.83	5.32	9.15

Imperial	Geothermal	East Mesa	75	-5.6	10.11	6.05	-5.6	8.36	9.15
Imperial	Geothermal	Heber	42	-4.55	5.53	6.05	-4.55	4.53	9.15
Imperial	Geothermal	Mount Signal	19	-4.5	5.60	6.05	-4.5	4.59	9.15
Imperial	Geothermal	Brawley North	135	-4.42	6.13	6.05	-4.42	5.51	9.15
Imperial	Geothermal	Brawley East	129	-4.42	9.32	6.05	-4.42	8.47	9.15
Imperial	Geothermal	Brawley Mesquite	62	-4.42	10.17	6.05	-4.42	9.25	9.15
Imperial	Geothermal	Dunes	11	-4.2	8.12	6.05	-4.2	6.7	9.15
Imperial	Geothermal	Niland	76	-3.97	7.38	6.05	-3.97	6.67	9.15
Imperial	Geothermal	Glamis	6	-1.02	9.76	6.05	-1.02	8.07	9.15
Imperial	Geothermal	Salton Sea	1400	-0.6	5.34	6.05	-0.6	4.78	9.15
PacifiCorp	Geothermal	Lake City/Surprise Valley Modoc County	37	-1.05	7.17	6.05	-1.05	6.48	9.15
PacifiCorp	Geothermal	Medicine Lake Telephone Flat	175	-0.48	5.39	6.05	-0.48	4.82	9.15
PacifiCorp	Geothermal	Medicine Lake Fourmile Hill	36	-0.48	6.21	6.05	-0.48	5.58	9.15
PacifiCorp	Geothermal	Honey Lake	2	0.375	5.49	6.05	0.375	4.49	9.15
PG&E	Geothermal	Sulfur Bank Field	43	-2.91	5.54	6.05	-2.91	4.96	9.15
PG&E	Geothermal	Geysers Sonoma & Lake County	400	-2.23	8.14	6.05	-2.23	7.74	9.15
PG&E	Geothermal	Calistoga Napa County	25	-1	7.86	6.05	-1	7.28	9.15
SCE	Geothermal	Long Valley Mono County	71	0.64	4.43	6.05	0.64	4	9.15
SCE	Geothermal	Coso Hot Spring Inyo County	55	5.17	7.70	6.05	5.17	6.97	9.15
SCE	Geothermal	Randsburg	48	5.35	6.08	6.05	5.35	5.47	9.15
PG&E	High Wind	Solano County	275	-0.67	3.38	6.05	-0.67	2.45	9.15
PG&E	High Wind	Alameda County	132	-0.125	3.38	6.05	-0.125	2.45	9.15
SCE	High Wind	San Bernardino County	168	-5.3	3.38	6.05	-5.3	2.45	9.15
SCE	High Wind	Riverside County	1416	-1.4	3.38	6.05	-1.4	2.45	9.15
SCE	High Wind	Tehachapi	1200	0.008	3.38	6.05	0.008	2.45	9.15
SDG&E	High Wind	San Diego	150	-1.6	3.38	6.05	-1.6	2.45	9.15
PG&E	Low Wind	CRAGVIEW	40	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	FLTN JT2	3	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	VACA-DXN	60	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	TRAVISJT	50	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	MAINE-PR	50	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	WINDMSTR	28	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	MOORPARK	50	-0.3	7.32	6.05	-0.3	4.02	9.15
State wide	Resid. Solar	Distributed	500	-2	16.76	11.9	-2	16.76	11.9
			9,431						

(Sources: LCOE & MW values from California Energy Commission; MPR from CPUC)

Geothermal Alternatives

After the completion of the technical potential for geothermal resource sites, twenty (20) sites were selected for transmission load flow analysis as shown in Table 1. These sites were selected, as were all of the sites, based on their close proximity to transmission hot spots. There are other sites that were not near transmission hot spots that were not included in this analysis. The total projected generation from these sites was 2,857 MW.

Four (4) geothermal sites were eliminated from further consideration in 2010 due to positive transmission impact ratios. Three of these geothermal sites are located in the Long Valley area. These are located in the eastern side of California in Southern California Edison (SCE) service area along the Highway 395 corridor. This area is mostly desert with little load. The three sites are connected together via the same transmission line. Various transmission upgrades were evaluated but the average impact ratio was a (positive) +4.39. The proposed Dixie Valley geothermal site in Nevada is interested in connecting to this transmission line. If more generation could be connected and a different interconnection point to the SCE service area could be found, then these projects could become economical. The fourth site eliminated was the Honey Lake site, which only had a two (2) MW of generation capability.

There were eleven (11) geothermal sites eliminated in 2010 since the LCOE was higher than the target LCOE. In 2017, all the sites except for Brawley Mesquite become economical. Even though Brawley North was slightly higher than the reference LCOE (6.13 vs. 6.05), Brawley North was considered eligible for 2010.

The Salton Sea geothermal site was studied at a potential of 1,171 MW. However, the project has increased in capacity to 2,000 MW. Due to transmission limitations, the projected available generation by 2010 would be 800 MW. Out of this 800 MW, IID has contracted for power from Salton Sea 6 and the remaining 600 MW is projected to be available in 200 MW block. After 2010, the Imperial Study Group anticipates that 200 MW could be available every even year. Under this assumption, another 600 MW could be available by 2017.

High Wind Sites

There were six (6) high wind sites selected for study in 2010 as shown in Table 1. All of these had negative transmission impact ratios which indicated that they all provided a benefit to transmission reliability. At the time of the study, the Tehachapi wind site had a projected connected capacity of 2000 MW. In completing the initial load flow studies, we determined that at a connected capacity of 1,200 MW, the impact ratio for Tehachapi was basically neutral (0.0008). At 2,000 MW, the projected impact ratio was a positive 1.57 which decreases transmission reliability. However, the Tehachapi site is now looking at a build-out ranging between 2,000 and 4,000 MW. The site would need to be re-evaluated under this new development potential.

But for this integration, we will be using the projection of 1,200 MW that had a neutral impact ratio. PG&E, SCE and others are undertaking extensive transmission studies to determine transmission expansion requirements. A report by the

Tehachapi Collaborative Study Group, dated March 16, 2005, describes the detailed and complex issues associated with transmission development from the Tehachapi wind site. The report only discusses part of the transmission expansion issues and the associated costs to deliver power to California. The SVA analysis indicates that delivering power from the Tehachapi wind site to load centers throughout California is complex and requires extensive studies by the collaborative.

There are many other high wind sites that should be evaluated. These could improve transmission reliability, be economical and reduce potential intermittency problems by distributing wind generation throughout the state.

Low Wind Sites

Although there are projected high penetrations of low wind potential around the high wind development sites listed above, we wanted to select sites that had only low wind potential only that could be developed near load centers and still be economical. Seven (7) sites were selected for transmission load flow analysis as shown in Table 1. These were considered to be distributed low wind sites and therefore were connected to the lower voltage transmission lines, where possible. Since the quantity of wind generation was low, these were all studied together which explains why they all have the same transmission impact ratio. The impact ratio for these sites was a negative -0.3. Since low wind turbines are not projected to be widely available until after 2010, these will be considered in the 2017 integration analysis.

Concentrated Solar (CSP Solar) Sites

Five counties were selected for concentrated solar installations as shown in Table 1. Plumas, San Diego and Imperial were not included in the 2010 penetration due to the low solar index. However, San Diego and Imperial were considered in 2017.

Residential Solar

There were 128 locations that were dispersed throughout California. These were located in areas that were projected to have high new housing developments. The average size of the aggregated residential solar installation at each location was 4.2 MW. These were considered to be load reducing installations that had no transmission costs. The impact ratio is projected to be at a negative 2.0 which indicates that residential solar is a good renewable resource alternative. We assumed a penetration of 500 MW in 2010 and another 500 MW in 2017 in anticipation of the residential housing solar initiative being considered by the State.

Biomass Forestry and Shrub Clearing

One of the best biomass alternatives for California is the clearing of forests to reduce fire threat and property damage while at the same time burning the wood waste. If locations could be found where small distributed generators could be installed, then we could both generate electricity and improve transmission reliability. Thirteen (13) sites were selected in northern California that had very high bone-dry-tons of wood waste as shown in Table 1. Temporary locations were selected within the forest clearing areas that could be connected directly to substations. As indicated by the high impact ratio, forest clearing and logging clearing of residual wood waste can generate electricity and reduce fire threats. Other areas in California should be investigated, especially in and around population centers. None of the selected sites were cost effective for 2010. For 2017, 382 MW were cost effective.

Distributed Biomass

Distributed biomass was considered to be land fill gas, waste water treatment plant, urban fuels and dairy manure. We selected 137 sites throughout California with a total projected generation of 952 MW or 6.9 MW per site. These were considered to be demand reducing renewables so there were no transmission costs. The impact ratio was very high. For 2010, the urban fuels were considered to be not available. We installed 228 MW of distributed biomass that was comprised of dairy manure, waste water treatment and landfill gas. In 2017, the penetration potential was another 724 MW that was comprised of dairy manure, waste water treatment, landfill gas and urban fuels for a total installed of 952 MW.

Renewable Penetration Targets for 2010 and 2017

For this integration process, we used the renewable energy projections and updated demand forecasts from the California Energy Demand 2006-2016 - Staff Energy Demand Forecast – Staff Draft Report, Posted June 15, 2005, California Energy Commission publication # CEC-400-2005-034-SD. The two tables used from this report were the table titled “Form 1.c Statewide California Energy Demand Forecast 2006-2016 Staff Forecast Retail Sales by Utility” and “Table 6 Procured versus Needed Renewable Energy to Reach 20 Percent by 2010”. The first referenced table details the demand forecasting results. The 2010 California total system energy consumption was projected to be 280,802 GWh. The 2017 energy consumption projection was 305,569 GWh. The difference between the two forecasts times 20 percent is the projected incremental renewable energy requirement by 2017. The incremental renewable energy addition is 4,953 GWh.

Table 6 of the report describes the process for determining the 2010 renewable energy requirements. By 2004, the utilities are projected to have 27,191 GWh of renewables in service. The projected 20 percent target by 2010 is 56,160 GWh. The difference of 28,969 GWh is the renewable penetration target that will be used in this study.

Table 2: 2010 Renewable Energy Penetration Requirements (GWh)

LSE	2001 estimated renewable baseline (GWh/yr)	2003 actual (GWh/yr) -7% loss {% 2003 APT}	2004 actual (GWh/yr) -7% loss {% 2004 APT}	2005 IOU expected (GWh/yr) -7% loss	2005 needed to be on course for 20% by 2010 (GWh/yr)	2010 20% of demand forecast (GWh/yr)	2010 IOU plans (GWh/yr)
PG&E	6,719	8,210 {101%}[b]	7,990 {91%}	8,451	9,633	15,879	14,790[a]
SCE	11,364	11,622[c] {104%}	12,319 {104%}	12,680	14,560	15,934	Redacted[d]
SDG&E	146	512 {285%}	631 {160%}	822	1,285	3,462	Redacted[d]
DA & Rest of state	7,587	6,384	6,252		13,132	20,885	
Total retail sales	25,816	26,728	27,191		38,610	56,160	

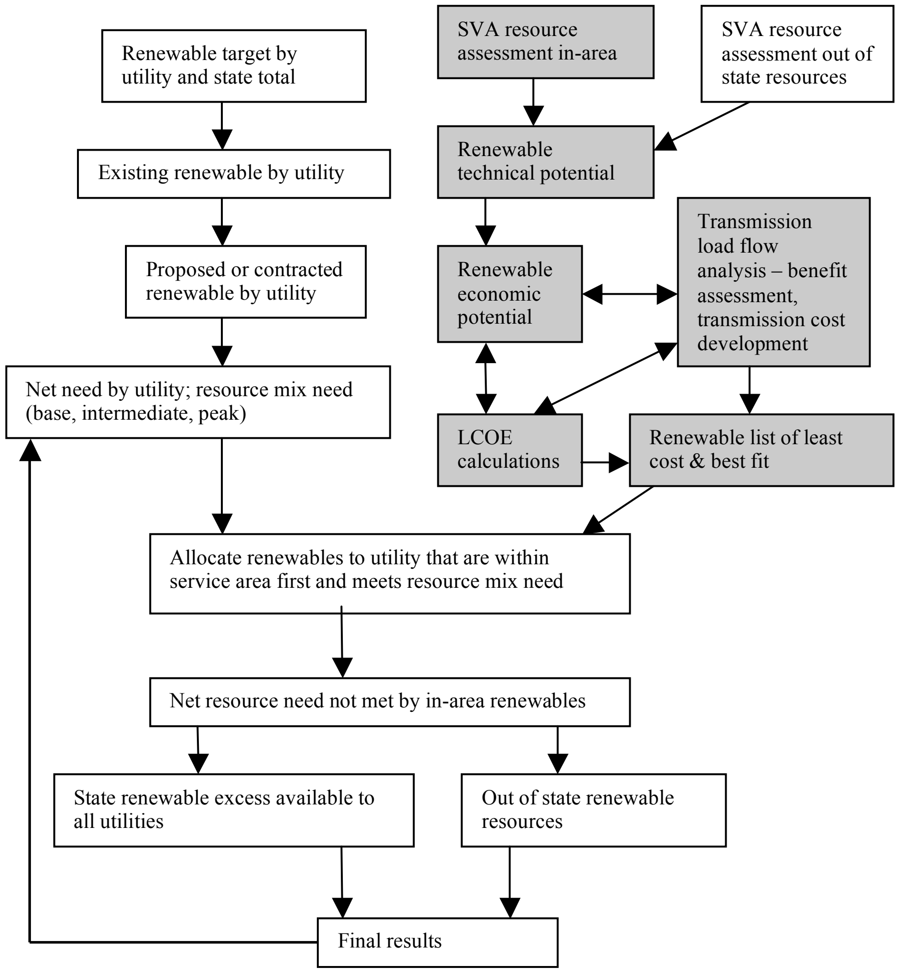
Source: California Energy Commission

Integration of Renewables

The flow chart for determining how renewables are integrated to meet the utilities renewable target is shown below in Figure 4. In the previous sections, the Energy Commission and DPC completed the steps highlighted (Resource Assessment, Technical Potential, Economical Potential and Transmission Impact). The short list of resource alternatives that met both the LCOE and transmission impact ratios are listed in the Table 1.

Ideally, these steps would have been completed for each utility or for a developer that wanted to use the SVA methodology to determine if its particular project would meet the SVA requirements. However, here the objective was to demonstrate how the methodology could be used to complete a state-wide evaluation.

Figure 4: SVA Methodology Flow Chart



2010 Renewable Technology Integration

The study considered summer peak load flow cases for 2010 and 2017 developed in prior analyses. These cases incorporate transmission upgrades, load growth, new permitted power plants and retirement of power plants for their respective time frames.

The renewable resources displaced in-state fossil fuel generators. Nuclear, base load units, reliability-must-run (RMR) units, and existing in-state renewable units maintained constant power output within each study year and were not displaced by renewable units. Units identified by the California Independent System Operator (CA ISO) as current or potential retirements were displaced, regardless of other status.

Our approach for determining the renewable resource mix was to start with the "demand reducing" technologies as shown in Table 1. These would be small, dispersed resources such as low wind speed turbines, residential solar, biomass and biomass forestry. The commercial availability of low wind speed turbines will be after the 2010 time period. The residential solar, biomass forestry and biomass misc. were staged in implementation. We then started to add renewable resources according to their operating type (base, intermediate and peaking). The installation order was geothermal, high wind and concentrated solar. We did not include any out-of-state resources because we did not receive any specific locations, costs and commercial operation dates.

Table 3: Projected Renewable Technology Penetrations by 2010

Location	Technology	Utility	MW	C.F. %	Energy
Salton Sea	Geothermal	Imperial	800	90.0%	6,307,200
Mount Signal	Geothermal	Imperial	19	90.0%	149,796
Heber	Geothermal	Imperial	42	90.0%	331,128
Brawley North	Geothermal	Imperial	135	90.0%	1,064,340
Sulfur Bank	Geothermal	PG&E	43	90.0%	339,012
Medicine Lake Telephone Flat	Geothermal	PacifiCorp	175	90.0%	1,379,700
Tehachapi	High Wind	SCE	900	37.0%	2,917,080
Riverside	High Wind	SCE	1,416	37.0%	4,589,539
San Bern	High Wind	SCE	168	37.0%	544,522
SDGE	High Wind	SDG&E	150	37.0%	486,180
Solano	High Wind	PG&E	275	37.0%	891,330
Altamont	High Wind	PG&E	132	37.0%	427,838
State wide	WWTP, LFGTE, Dairy	State wide	228	90.0%	1,797,552
Riverside	CSP Solar	SCE	599	27.0%	1,416,755
San Bern	CSP Solar	SCE	447	27.0%	1,057,244
State wide	Res Solar	State wide	500	20.0%	876,000
Total			6,029		24,575,216
20% Requirement					28,969,000
Net					(4,393,784)

According to the limited renewable technology sites that were available for 2010, we were only able to meet 85 percent of the penetration target for 2010. We did not meet the 20 percent penetration due to several reasons:

- We did not complete an exhaustive search of all of the renewable potential sites in California
- Some of the sites did not meet the criteria
- We did not include out-of-state resources due to a lack of data
- We did not have the latest data available from the utilities on recently contracted renewables
- It was not our intent to force the meeting of the 20 percent but to demonstrate how the methodology can be used to evaluate potential sites.

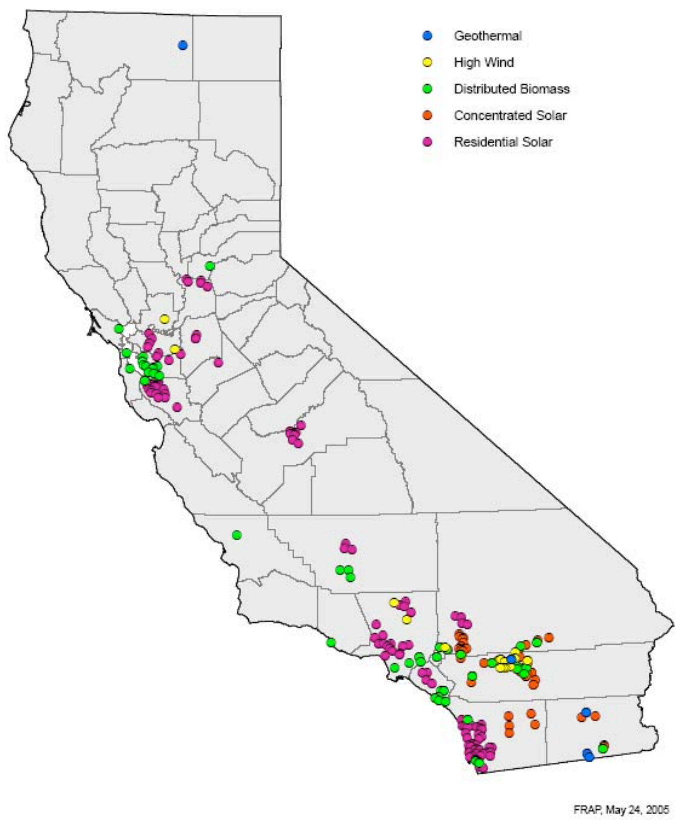
Table 4 shows the 2010 projected capacity and associated energy that was projected to be available by technology type from the renewable technology list in Table 1. The majority of the capacity is projected to be from high wind turbine sites while the majority of the energy is projected to be distributed between geothermal and high wind.

Table 4: Projected Renewable Energy by Resource Type

Technology	MW	Mix %	C.F. %	Energy	Mix %
Geothermal	1,214	20%	90.0%	9,571,176	39%
Biomass-dairy manure, wastewater, landfill gas	228	4%	90.0%	1,797,552	7%
High Wind	3,041	50%	37.0%	9,856,489	40%
CSP Solar	1,046	17%	27.0%	2,473,999	10%
Res Solar	500	8%	20.0%	876,000	4%
Total	6,029	100%	46.5%	24,575,216	100%
20% Requirement			85%	28,969,000	
Net Short				(4,393,784)	

The California map in Figure 5 below shows the distribution of the renewable resources selected in the 2010 evaluation. As you can see, most of these will be located in southern California.

Figure 5: Location of Renewables for 2010 (source: California Department of Forestry)



When we developed the complete 2010 integrated case using the renewable resources shown above, there were three lines overloaded in the renewable base case. These lines had to be upgrades before any contingency analysis.

The AMWCO value for the 2010 base case was 13,301 MW. After we added 5,694 MW of renewables from the renewable mix shown in Table 3, the AMWCO decreased to 12,024 MW. The lower AMWCO indicates a higher level of transmission system reliability. The difference between the two AMWCO values divided by the connected renewable resources is the transmission impact ratio. A negative value provides a benefit. A positive decreases transmission reliability. In this case, the impact ratio was a (negative) -0.224. The new renewable resources, which were essentially installed in southern California, provided transmission relief to the southern part of the system.

In an attempt to improve the transmission impact ratio, we analyzed the transmission overloads that were driving the impact ratio low. Ten transmission lines were responsible for 1,088 MW or 67 percent of all increases in contingency overloads from the base case to the integrated case.

As a sensitivity case, we upgraded all ten lines and completed another load flow. The AMWCO for the renewable case decreased from 12,024 to 9,402. These changed the impact ratio from -0.224 to -0.685. Additional analysis is suggested to fully understand the cause of the low impact ratio. Some of the causes could be attributed to:

- No re-dispatch of the existing in-area resources to optimize resources
- Continued high import levels from out-of-state resources
- Location of RMR units may need to be moved to other units
- Transmission system is operating at or near maximum capacity

2017 Renewable Technology Integration

In Table 1 above, there were some renewable technology sites that had higher LCOE than the referent resource in 2010. Any cost effective renewables in 2017 were included in the list of available resources in meeting the 20 percent penetration. Table 5, below, shows the incremental resources added in 2017.

Table 5: 2017 Renewable Technology Penetrations

Location	Technology	utility	MW	C.F. %	Energy
Salton Sea	Geothermal	Imperial	400	90.0%	3,153,600
Niland	Geothermal	Imperial	42	90.0%	331,128
Fire Threat	Biomass	State wide	132	85.0%	982,872
State wide	WWTP, LFGTE, Dairy, Urban fuels	State wide	320	90.0%	2,522,880
Tehachapi	High Wind	SCE	300	37.0%	972,360
Contra Costa	Low Wind	PG&E	28	25.0%	61,320
Siskiyou	Low Wind	PacifiCorp	41	25.0%	89,790
Ventura	Low Wind	SCE	50	25.0%	109,500
Yolo	Low Wind	PG&E	3	25.0%	6,570
San Diego	CSP Solar	San Diego	35	27.0%	82,782
Imperial	CSP Solar	Imperial	66	27.0%	156,103
All	Res Solar	State wide	500	20.0%	876,000
Total			1,917	55.6%	9,344,905
20% Requirement					4,953,000
2010 Carryover					4,393,784
Net					(1,878)

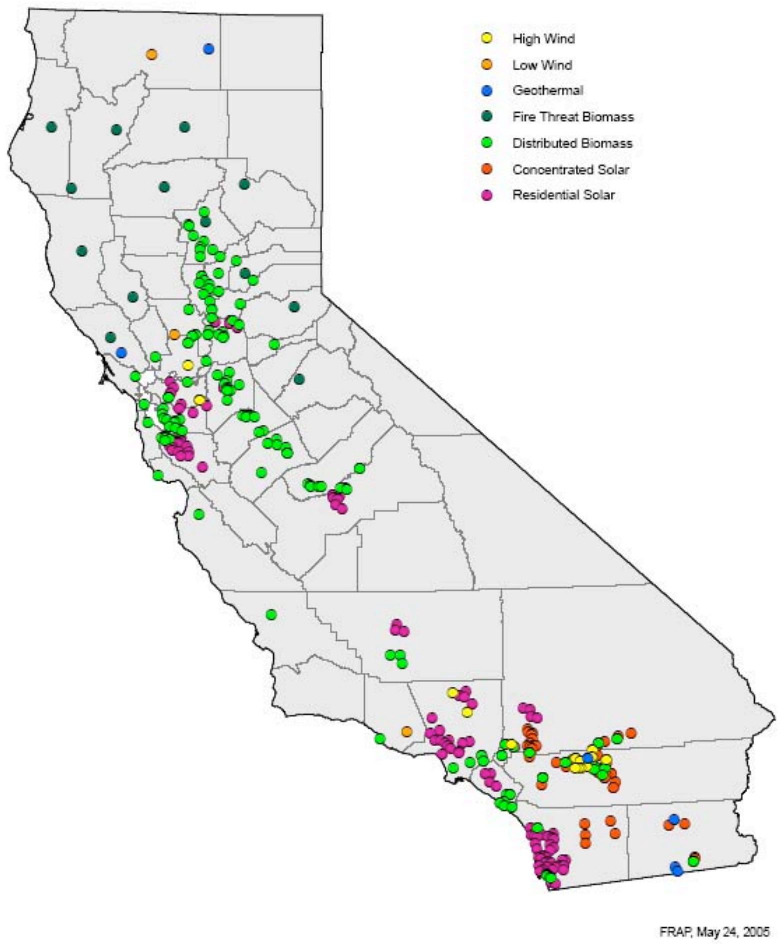
Table 6 shows the 2017 projected capacity and associated energy that was projected to be available by technology type from the renewable technology list in Table 1. The majority of the capacity is projected to be from high wind turbine sites while the majority of the energy is projected to be distributed between geothermal and high wind.

Table 6: 2017 Projected Renewable Energy by Resource Type

Technology	MW	Mix %	C.F. %	Energy	Mix %
Geothermal	442	23%	90.0%	3,484,728	37%
Biomass Forestry	132	7%	85.0%	982,872	11%
Biomass-Urban fuels, dairy manure, wastewater, landfill gas	320	17%	90.0%	2,522,880	27%
High Wind	300	16%	37.0%	972,360	10%
Low Wind	122	6%	25.0%	267,180	3%
CSP Solar	101	5%	27.0%	238,885	3%
Res Solar	500	26%	20.0%	876,000	9%
Total	1,917	100%	55.6%	9,344,905	100%
20% Requirement				9,346,784	
Net				(1,878)	

In 2017, we added the generation from the Salton Sea geothermal, Tehachapi wind generation, biomass, and concentrated solar. We added some distributed low wind speed turbines, the Geysers geothermal generation and the biomass forestry generation. Due to the lower penetration requirements for 2017, we did not need to add all of the Salton Sea, fire threat renewables and other biomass resources. As shown in Table 5, we were able to meet the 20 percent renewable penetration. There were additional in-area renewables available to construct as well as out-of-state renewable resources which were not included. As out-of-state data becomes available, we may discover that some of these could be cheaper than the in-area resources. The following map as shown in Figure 6 shows the distribution of these resources through the California.

Figure 6: 2017 Renewable Technology Penetrations (source: California Department of Forestry)



In the 2017 base case, there were twelve (12) transmission lines that needed to be upgraded. When we added the 2,729 MW of renewable technologies, we had fifteen (15) overloaded lines in the modified renewable base case. These were upgraded before running any contingency analysis.

When we completed the contingency analysis, the transmission impact ratio was -0.982. For every 1 MW of new renewable technology added, we were able to reduce the transmission system reliability index by 0.982. However, there were thirteen (13) overloaded lines in the contingency case.

We performed a preliminary assessment on how the impact ratio could be improved by focusing on individual transmission lines that experienced increased contingency MW overloads after the renewable integration. If all of these lines were upgraded and a new load flow case completed, the new AMWCO would be 16,765 as compared to the base AMWCO of 27,803 MW. The new impact ratio would be negative a -1.25.

Similar to 2010, there needs to be additional load flow analysis to determine the cause of the low impact ratios and the value of upgrading these lines. If there are only a few lines that impact the impact ratio, then upgrading the lines would be more likely. If the impact ratio is distributed over numerous lines, then more detailed analysis needs to be completed to determine if adjustments to RAS, RMR or plant retirements are needed. Some of the causes could be attributed to:

- No re-dispatch of the existing in-area resources to optimize resources
- Continued high import levels from out-of-state resources
- Location of RMR units may need to be moved to other units
- Transmission system is operating at or near maximum capacity

Table 6 shows the installed renewable technologies that were added in 2017. Table 7 shows the total renewables added over the entire study period.

Table 7: Total Renewable Technology Installed by 2017

Technology	MW	Mix %	C.F. %	Energy	Mix %
Geothermal	1,656	21%	90.0%	13,055,904	38%
Biomass Forestry	132	2%	85.0%	982,872	3%
Biomass-Urban fuels, dairy manure, wastewater, landfill gas	548	7%	90.0%	4,320,432	13%
High Wind	3,341	42%	37.0%	10,828,849	32%
Low Wind	122	2%	25.0%	267,180	1%
CSP Solar	1,147	14%	27.0%	2,712,884	8%
Res Solar	1,000	13%	20.0%	1,752,000	5%
Total	7,946	100%	48.7%	33,920,122	100%
20% Requirement				33,922,000	
Net				(1,878)	

Figure 7 is a pie chart that shows the resulting capacity mix of renewable technologies by 2017. From this analysis, forty-three (43) percent of the capacity will be from high and low wind speed turbines with geothermal next at twenty-one (21) percent. The other renewables are approximately equal in percentages.

Figure 7: Renewable Technology Capacity Mix

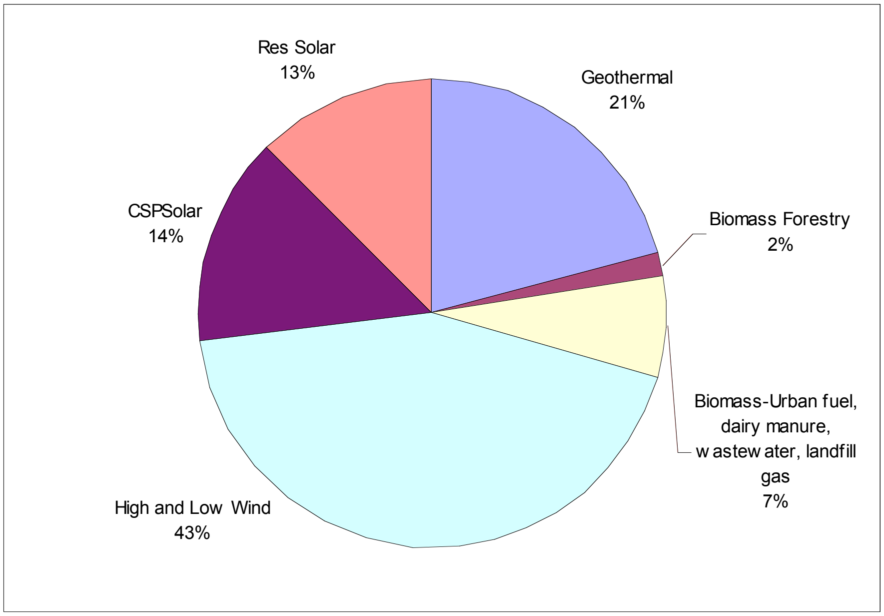
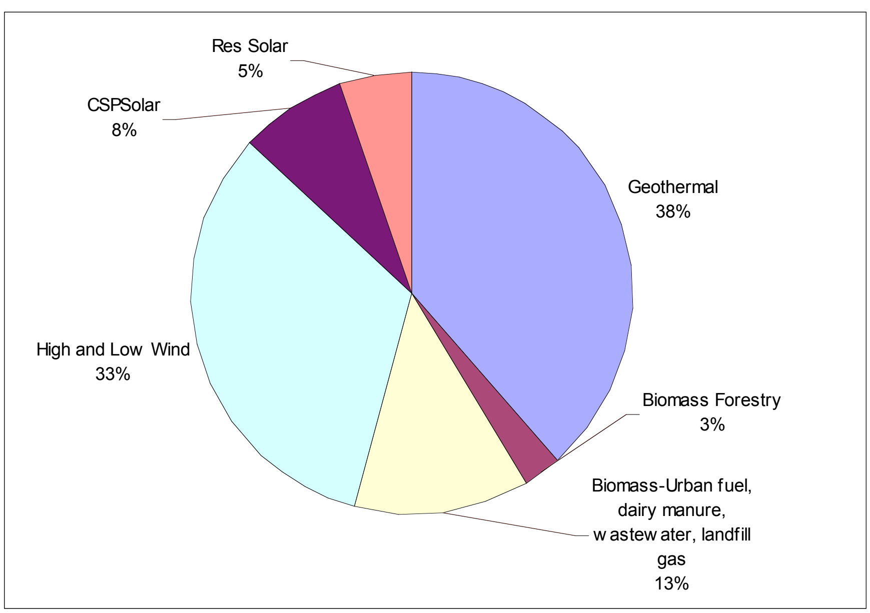


Figure 8 is an energy distribution pie chart that shows a different distribution of the energy of the renewable resources. Geothermal and wind resources will contribute thirty-four (34) percent and thirty-three (33) percent, respectively.

Figure 8: Renewable Technology Energy Mix



A more interesting observation is that seventy (70) percent of the capacity and forty-six (46) percent of the energy will be from intermittent resources such as wind and solar. As we continue to refine the renewable resource mix, it will be interesting to observe what the final mix could be and the impact that intermittent resources could have on transmission operations.

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APPENDIX A: Development of the Aggregated Case for California 2007: Final Report

Executive Summary

This document describes PowerWorld and Davis Power Consultant activities related to the construction of the aggregated case for the summer peak of 2007. This aggregated case will be subject to contingency and hot spot analysis, as well as distributed generation solutions for 2007. This case will also be utilized during the development of power flow models for other years considered in this study.

The goal of the aggregation processes was to obtain a single case that models each control area exactly as the corresponding utility does for the summer peak of 2007. For every area, the reliability analysis of the aggregated case will produce results compatible with those that would be obtained if separate cases were utilized. The aggregated case though has the advantage of allowing fully integrated and highly consistent hot spot evaluation and determination of potential generation expansion solutions.

The 2007 aggregation process considered two phases. In the first phase, the PG&E "Area 1" summer peak model for 2007 was scaled to obtain a robust representation of the system demand and generation profile for that year. An extrapolation of the demand indicators for 2003 and 2005 was utilized in order to calculate the required 2007 demand and generation levels. Several assumptions regarding area control error (ACE) and load power factor were applied during the proportional scaling. In addition, new generation was committed to operation in PG&E system according to the level required by demand growth.

In the second phase, the available 2007 case from SCE and SDG&E were incorporated into the PG&E model. LADWP data was assumed to be accurately modeled by SCE and IID was modeled after the 2007 PG&E case. During the aggregation process, a record labeling method was utilized to ensure that the power flow solution was retained, and that topology and interchange issues can be resolved.

The cases analyzed during this process presented several discrepancies, involving series capacitor operation, topological modeling, and area interchange.
In particular, there is a direct discrepancy in the model of the SDG&E – SCE tie line from bus 24151 VALLEYSC to bus 22000 RAINBOW, circuit 1, which is modeled in the PG&E target and SCE cases, and not in the SDG&E case. Nevertheless, the aggregated case for the California 2007 summer peak is robust enough to support hot spot, WTLR determination, and further locational value analysis of distributed generation.

Background: Data Availability and Handling

This section discusses the data availability from each control area in California and determines the source cases utilized during the 2007 case aggregation.

PG&E submitted the Area 1 summer peak case of 2007 during the summer of 2002. This case is a valid power flow solution, but includes a forecast level incompatible with the Area 7-8 2003 and 2005 sequence. Consequently, this case needed to be scaled to obtain the most likely scenario for 2007. The scaling process for PG&E is detailed in Section 3 of this report.

DPC received the San Diego Gas & Electric and Southern California Edison 2007 summer peak cases from the California Energy Commission in January 2003. The initial exploration of the cases by means of power flow solution indicated that this case could be utilized for the aggregation process.

Regarding LADWP, this control area was modeled after the SCE case. Please see the case aggregation report of 2003 for data limitations in the LADWP data. The SCE model includes area growth for LA in 2007, and thus, it corresponds to the best available model for that specific year.

No data sets were received from the Imperial Irrigation District. The results of the simulation will be supported by the IID data as modeled in the PG&E case. Having a model of IID is necessary to identify hot spots and determine WTLR sensitivities in other California areas.

PG&E Scaling for 2007

This section describes the scaling process on the PG&E 2007 model. This process was required to achieve a level of demand and generation consistent with the load growth seen in 2003 and 2005 in this control area.

Power System Scaling

Power system scaling is the process of modifying a similar set of variables in the power system in order to achieve a model that represents a new condition. Scaling is generally related to load, which is the variable that determines generation commitment and dispatch, as well as other system controls.

Load scaling is performed when there is no specific information regarding bus load forecast for a power flow model. Utilities have generally available system load forecast data, production costing studies for a set of scenarios, and a power flow case that can be used as a base for scaling.

The rather standard scaling approach utilized for this study includes the following considerations:

- Definition of the area control to be scaled (PG&E)
- Proportional scaling of active power load.
- Scaling of reactive power load to keep constant power factor
- Proportional scaling of generation based on participation factors to keep area control error (ACE) constant.

The process is complete when a successful solution of the AC power flow problem is achieved. Note than in general, the positive scaling of a control area variables will ultimately be limited by voltage collapse (loading margin) for normal operation. It is expected that the validity of the system scaling decreases as the multiplier utilized increase. For voltage collapse, a 10 to 20 percent scaling is acceptable without transmission expansion in a well-conditioned power system.

Scaling of the PG&E 2007 Model

PG&E provided the Area 1 model for 2007, which needed to be scaled in order to reflect the demand growth after the Area 7-8 PG&E models of 2003 and 2005. Table 1 provides the required information to develop system scaling factors.

Exploration of the table reveals that the load of 2007 is actually smaller than the one of 2005. In order to obtain the PG&E load level for 2007, as simple extrapolation process was followed considering the load values of 2003 and 2005, which resulted in a multiplier of 1.0418? In order to check the level of load growth, a second multiplier was obtained from the CALIFORNIA ENERGY COMMISSION production costing model of 2005 and 2007, which was equal to 1.04056. The difference is therefore negligible for load scaling and the resulting PG&E load for 2007 was equal to 25,586 MW.

A second problem with the area 1 model was that not enough generation was online in PG&E to meet the 25,586 MW load, and match the schedule interchange of 1,873 MW imports. Consequently, system studies were reviewed in order to determine the generators that are to be online in 2007, and to commit them in the case.

Table 1: Area Records for 2003, 2005, and 2007

2003 California Aggregated Case							
Num	Area Name	AGC Status	Gen MW	Load MW	Sched MW	Int MW	ACE MW
21	IMPERIAL	Area Slack	963.74	790	155.6	154.22	-1.38
22	SANDIEGO	Area Slack	1316.51	4067.05	-2850	-2850.05	-0.05
24	SOCALIF	Area Slack	14552.62	20308.98	-6161.6	-6158.96	2.64
26	LADWP	Area Slack	3746.06	5431.7	-2183	-2174.46	8.54
30	PG AND E	Off AGC	22696.75	23575.08	-1869	-1882.29	-13.29
40	NORTHWES	Part. AGC	32565.27	26650.33	4631	4631.21	0.21
50	B.C.HYDR	Part. AGC	10889.65	6973.68	3300	3300.51	0.51
52	W KOOTEN	Part. AGC	672.95	752.47	-100	-100.06	-0.06
54	ALBERTA	Part. AGC	8924.4	8721	-200	-200.11	-0.11
60	IDAHO	Part. AGC	4373.37	3245	891	890.88	-0.12
62	MONTANA	Part. AGC	3025.75	1677.77	1239	1239.07	0.07
63	WAPA U.M	Part. AGC	60.45	-79.4	129	129.21	0.21
64	SIERRA	Part. AGC	1286.23	1660.09	-433	-433	0
65	PACE	Part. AGC	6436.84	6992.7	-850	-850.44	-0.44
70	PSCOLORA	Part. AGC	5983.78	6910.15	-1111.7	-1111.81	-0.11
73	WAPA R.M	Part. AGC	5610.02	4029.15	1422.5	1422.04	-0.46
2005 California Aggregated Case							
21	IMPERIAL	Area Slack	969.59	790	155.6	158.02	2.42
22	SANDIEGO	Area Slack	1748.37	4420.66	-2801	-2798.96	2.04
24	SOCALIF	Area Slack	15540.08	21853.26	-6764	-6751	13
26	LADWP	Area Slack	5599.41	6250	-1170.6	-1171.72	-1.12
30	PG AND E	Off AGC	23687.48	24560.08	-1867	-1883.48	-16.48
2007 PG&E Area 1 case (not scaled)							
21	IMPERIAL	Area Slack	968.37	790	155.6	156.85	1.25
22	SANDIEGO	Area Slack	2326.06	3854.2	-1603	-1608.95	-5.95
24	SOCALIF	Area Slack	16408.82	22248.14	-6298	-6289.41	8.59
26	LADWP	Area Slack	5309.24	6466.53	-1561	-1672.36	-111.36
30	PG AND E	Off AGC	20547.2	21451.64	-1873	-1868.41	4.59

The generation commitment process started by identifying the differences in the generation that was online in the 2005 area 7-8 and 2007 area 1 cases. There were 68 generators with a different status in these two cases. Out of these 68 generators, 30 units corresponded to two or more units were connected to the same bus, with one unit online in 2005 and the other unit online in 2007. There were three new in the model. Four units had been retired. Finally, 15 units that were off-line in the case were identified to be available for 2007. For the reminder 16 generators there was not enough information to determine their availability in 2007.
The mentioned 15 units were committed in order to have enough online generation to withstand generator outages, and area listed in Table 2. As a result of this process 2,239 additional MW from these units was available after case scaling.

The initial attempt to reach a solution for the scaled case was not successful. The problem was tracked down to bus 30000 in PG&E being also the system slack. During the failed solution, the generation output of this unit was brought to about

2200MW, for a unit with a 710 MW limits. This slack bus reference was changed to Morro, which is the same slack bus in the 2005 model. This modification allowed us to reach a power flow solution.

Table 2: Units Brought Online for 2007

Generation Unit			Generation 2005		Generation 2007		
Bus	Name	ID	Status	Output (MW)	Status	Output (MW)	New Output
34600	HELMS 1	1	Closed	0	Open	0	0.00
35070	LAPLM_G1	1	Closed	279.6	Open	0	268.19
35071	LAPLM_G2	1	Closed	162.67	Open	0	268.19
35072	LAPLM_G3	1	Closed	162.67	Open	0	268.19
35073	LAPLM_G4	1	Closed	168.9	Open	0	268.19
35076	ELKHIL1G	1	Closed	224.1	Open	0	157.49
35077	ELKHIL2G	1	Closed	184.78	Open	0	157.49
35078	ELKHIL3G	1	Closed	184.78	Open	0	216.19
35081	SUNSET1G	1	Closed	0	Open	0	169.72
35082	SUNSET2G	1	Closed	0	Open	0	169.72
35083	SUNSET3S	1	Closed	0	Open	0	169.72
35851	GROYPKR1	1	Closed	31.74	Open	0	42.08
35852	GROYPKR2	1	Closed	5	Open	0	42.08
35853	GROYPKR3	1	Closed	4.35	Open	0	42.08
37958	RDGCT4	1	Closed	36.35	Open	0	0.00
TOTAL							2239.33

In order to validate the power flow solution, the system voltages were evaluated. It was determined that the following buses presented per unit voltages outside the range from 0.9 to 1.1 p.u.

Table 3: Bus Voltages outside the 0.9 to 1.1 per unit range in PG&E

Number	Name	PU Volt	Volt (kV)
31456	MALACHA1	1.10422	126.986
32388	FRNCH MS	1.10359	66.216
34378	GATES	1.10331	126.881
33900	DONNELLS	1.10058	126.566
30451	CRTNA M	0.89652	206.199

The next step was to explore the line base case violations in the PG&E area. Table 4 lists the base case violations considering the normal operation thermal limit (Limit A). These limits are reported for further reference and analysis.

Table 4: Overloaded Lines in Normal Operation (Limit A) after Scaling

From Number	From Name	To Number	To Name	Ckt	Limiting Flow	Limit	%	MVA/ Amps?
30419	CR1T4_23	30430	FULTON	1	1262.9	976.5	129.3	Amps
33800	SALT SPS	38100	SPICER	1	174.8	137.5	127.2	Amps
33020	MORAGA	33010	SOBRANTE	1	1251.7	1021.2	122.6	Amps
32782	STATIN D	32788	STATIN L	1	860.0	790.2	108.8	Amps
30562	TES JCT	30631	NEWARK E	1	1072.9	1004.1	106.9	Amps
33008	GRIZLYJ2	32780	CLARMNT	1	857.0	803.3	106.7	Amps
30527	PITSBG E	30564	E. PIT11	1	1267.1	1207.4	104.9	Amps
37520	OBANION	37546	ELVERTAW	2	1101.7	1054.3	104.5	Amps
37520	OBANION	37546	ELVERTAW	1	1101.7	1054.3	104.5	Amps
37558	KESWICK	37641	SPRINGCR	2	517.6	500.0	103.5	Amps
30526	PITSBG D	30555	SANRAMON	1	1198.2	1162.2	103.1	Amps
30421	CR2T4_23	30435	LAKEVILE	1	1622.1	1594.0	101.8	Amps
30527	PITSBG E	30706	SANPIT11	1	1176.5	1162.2	101.2	Amps

Since the methodology for hot spot determination and analysis in California is based on contingency analysis. It is also important to determine the performance of the system if the limit B, which is utilized in contingency analysis, is utilized.

Table 5: Overloaded Lines with Limit B after Scaling

From Number	From Name	To Number	To Name	Ckt	Limiting Flow	Limit	%	MVA/ Amps?
30419	CR1T4_23	30430	FULTON	1	1269.4	976.5	130.0	Amps
33800	SALT SPS	38100	SPICER	1	175.0	137.5	127.3	Amps
33650	WEBER 1	33662	WEBER 2	1	1458.9	1199.9	121.6	Amps
37520	OBANION	37546	ELVERTAW	1	1104.5	1054.3	104.8	Amps
37520	OBANION	37546	ELVERTAW	2	1104.5	1054.3	104.8	Amps
37558	KESWICK	37641	SPRINGCR	2	519.8	500.0	103.9	Amps
30421	CR2T4_23	30435	LAKEVILE	1	1626.9	1594.0	102.1	Amps
31458	MALACHA2	30186	MALACHA2	2	35.2	35.0	100.5	MVA

It is important that if any, the base case violations are not reported during contingency analysis, since they will appear as violations for every contingency, which will result in distortion in the hot spots indicators. There are three mechanisms to avoid that distortion:

- Do not monitor the individual elements that are overloaded during normal operation (Limit B in this case). Each individual element in the program can be set up to either being monitored or not.
- Set the contingency analysis to not report the violations in elements that were overloaded in the contingency reference (base case), and then set up the base case to monitor limit B.
- Resolve slight base case violations (less than 5%) by performing a case by case generation redispatch. This process mimics what would be done during “real life” operation.

It was determined that because some of the line violations were introduced as direct result of the generation scaling, the first three branches in Table 5 should not be monitored and be evaluated separately, and the reminder branches with overloads of less than 5%, be mitigated using generation re-dispatch.

At the end of the redispatch process, there were no case violations in the system. It is important to recall that the monitoring does not consider radial lines.

Case Aggregation Methodology

A detailed case aggregation methodology was developed and presented in the case aggregation report for 2003. This methodology is the standard PowerWorld approach to merge large-scale power flow cases with the same bus numbering.

The aggregation methodology is the cornerstone of the process leading to robust cases of the California electric system. The merging process is based on control area records and it consists in passing records from the utility official cases into an integrated target case. During the process power flow convergence is retained and regional control settings are adjusted. The methodology considers the following phases, which were covered in depth in the mentioned report:

- Case initial solution and assignment
- Data exploration
- Data aggregation and solution
- Verification of external area topology
- Area interchange adjustment

For 2007, a record labeling process was also utilized for the data aggregation phase. This process considers the following strategy:

- Label all the records in the source
- Pass the labeled records for the corresponding area to the target
- Attempt to solve the power flow
- Analyze the unlabeled records and proceed to remove them from the model.
- Resolve the power flow.

Aggregation of SDG&E 2007

This section describes the aggregation process of SDG&E information into the PG&E data set for 2007.

Data Exploration and Aggregation

In this phase, a comparison of the data contained in the source and target cases was performed to verify that bus numbering, topology, and operating states were compatible. This data exploration is done to achieve convergence.

The first step in data exploration is to examine the area records shown in Table 6. The SDG&E load modeled in the source is about 900MW higher than in the target. Generation, on the other hand is lower. These differences result in a scheduled interchange difference of about 1,250MW. Some of this flow comes from Arizona, but it may also be caused by changes in the SCE model. It is important to note that the 1,250 additional imports to SDG&E are likely to require additional transmission. Consequently, we would expect changes in the topology not only inside SDG&E, but also in its surrounding areas.

Table 6: Area Records in the Target Scaled PG&E Case and the SDG&E Source

Area		PG&E 2007 Scaled (Target)			SDG&E 2007 (Source)		
#	Name	Gen MW	Load MW	Sched. MW	Gen MW	Load MW	Sched. MW
10	NEW MEXI	2887.37	3312.3	-571.5	2921.26	3526.94	-750.4
14	ARIZONA	17069.33	15144.49	1546	17950.27	15186.53	2345
18	NEVADA	3451.55	5651.84	-2267.1	3269.56	5886.94	-2710.9
19	WAPA L.C	3739.15	138.3	3430	3872.8	125.4	3578.1
20	MEXICO-C	2332.72	2308.9	0	2224.23	2192.56	0
21	IMPERIAL	968.37	790	155.6	1015.34	790	203.2
22	SANDIEGO	2326.06	3854.2	-1603	1992.12	4733.19	-2850
24	SOCALIF	16408.82	22248.14	-6298	16842.77	21724.17	-5328.5
26	LADWP	5400.76	6466.53	-1561	5628.61	6490	-1377
30	PG AND E	24803.33	25586.54	-1887.8	21736.43	22783.49	-1880
40	NORTHWES	32718.8	26650.33	4771	30624.21	25435.49	4050
50	B.C.HYDR	10888.65	6973.68	3300	10194.28	7046.08	2570
52	W KOOTEN	672.94	752.47	-100	737.74	589.9	130
54	ALBERTA	8924.4	8721	-200	8382.01	8425.3	-400
60	IDAHO	4377.33	3245	891	4226.78	2917	1114
62	MONTANA	3026.69	1677.77	1239	3050.39	1592.61	1366
63	WAPA U.M	59.64	-79.4	129	39.42	-95	125
64	SIERRA	1287.22	1660.09	-433	1204.05	1667.3	-523
65	PACE	6438.42	6992.7	-850	5016.17	4598.09	210.4
70	PSCOLORA	5986.95	6910.15	-1111.7	5163.36	5942.26	-952.8
73	WAPA R.M	5625.83	4029.15	1422.5	4517.11	3289.29	1080.9

Modeling Discrepancies

In order to maintain power flow convergence in a more constrained case, such as 2007, the merging process utilizes a record labeling method in which the individual control area source records are flagged and then imported into the target. Those records that are not flagged at the end of the process are removed from the model. This allowed us to achieve the exact model used by the utility in the source data sets and at the same time to retain the power flow solution.

San Diego presented substantial differences in the way its source model was developed. For instance, all loads had ID label of 10 instead of 1. Since the data passing from the SDG&E case into the PG&E target was based on record flagging, this process resulted in object duplication. The labeling process was modified to take this issue into account.

The following generators where removed after the area records were passed into the target. In order to retain power flow solution, the generators were first opened, and then removed from the model.

Table 7: Generators Removed from the Target Model

Bus	Name	ID	Status	Gen MW	Gen Mvar	Set Volt	AGC	AVR	Min MW	Max MW
22208	EL CAJON	1	Open	0.00	0.00	1.01	YES	YES	0.00	49.80
22606	OTAYMGT2	1	Closed	172.00	42.18	1.00	YES	YES	0.00	172.00
22604	OTAY	2	Open	0.00	0.00	1.03	YES	YES	0.00	49.90
22001	RAINBOW	UP	Closed	0.00	-246.1	0.99	YES	YES	0.00	0.00
22496	MISSION	1	Open	0.00	0.00	1.01	YES	YES	0.00	49.80
22256	ESCNDIDO	2	Open	0.00	0.00	1.02	YES	YES	0.00	49.80
22605	OTAYMGT1	1	Closed	172.00	42.18	1.00	YES	YES	0.00	172.00
22504	MISSION	SC	Closed	0.00	20.04	0.99	YES	YES	0.00	0.00
22076	BORDER	1	Open	0.00	0.00	1.03	YES	YES	0.00	49.80
22256	ESCNDIDO	1	Open	0.00	0.00	1.02	YES	YES	0.00	49.80
22607	OTAYMST1	1	Closed	214.00	65.64	1.00	YES	YES	0.00	214.00
22076	BORDER	2	Open	0.00	0.00	1.03	YES	YES	0.00	49.80

The line from bus 24151 VALLEYSC to bus 22000 RAINBOW, circuit 1, was modeled in the PG&E target, and not in the SDG&E sources. This is a tie line from SDG&E to SCE, which is also modeled in the SCE source case. The line carries about 1,000 MW flow in the PG&E model. This represented a direct discrepancy in the topological modeling. This discrepancy is likely to affect flows in the region. This line was left in the model with opened status and requires further analysis.

Finally, Figure 1 shows a topological difference in the series capacitor of the lines from IMPRLVLY to Miguel. In the target this series capacitor is bypassed, WHEREAS in the SDG&E source the capacitor is closed. Operation of the line with the series capacitor in service results in more than 800MW flowing through that element. The series capacitor helps bringing more power into San Diego.

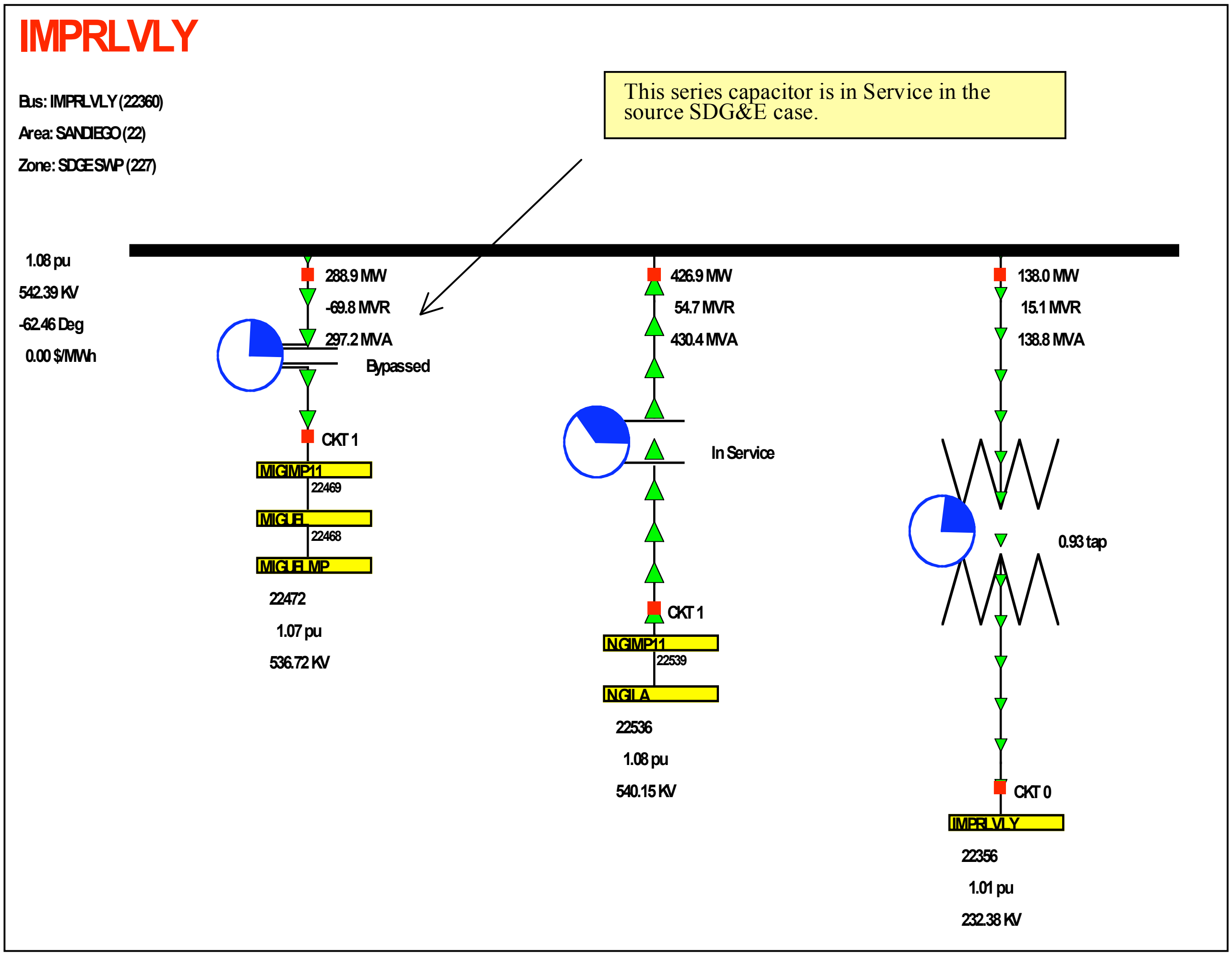

Figure 1: Series Capacitor Status in the SDG&E Case

Aggregation of SCE and LA 2005

Data Exploration and Aggregation

In this data exploration, the target case corresponds to the PG&E scaled case, and the source corresponds to the SCE + LA system. Table 4 shows the corresponding area records.

Table 8: Area Records in the Target and Source Cases

Area		PG&E Scaled 2007 (Target)			SCE + LA 2007 (Source)		
#	Name	Gen MW	Load MW	Sched MW	Gen MW	Load MW	Sched MW
10	NEW MEXI	2887.37	3312.3	-571.5	2745.65	2893.26	-325.8
14	ARIZONA	17069.33	15144.49	1546	20769.17	16193.01	4210
18	NEVADA	3451.55	5651.84	-2267.1	4497.5	6023.5	-1602
19	WAPA L.C	3739.15	138.3	3430	4599.53	137.7	4289
20	MEXICO-C	2332.72	2308.9	0	2168.97	1994.81	150
21	IMPERIAL	968.37	790	155.6	845.5	829	0
22	SANDIEGO	2326.06	3854.2	-1603	1301.92	4775.03	-3600
24	SOCALIF	16408.82	22248.14	-6298	16431.16	22037.82	-6079
26	LADWP	5400.76	6466.53	-1561	5272.45	6269.12	-1494
30	PG AND E	24803.33	25586.54	-1887.8	23936.04	25024.31	-1977
40	NORTHWES	32718.8	26650.33	4771	29144.21	23282.59	4641
50	B.C.HYDR	10888.65	6973.68	3300	11107.64	7188.13	3275
52	W KOOTEN	672.94	752.47	-100	554.07	635.27	-100
54	ALBERTA	8924.4	8721	-200	7377.7	7437.9	-400
60	IDAHO	4377.33	3245	891	3550.95	3039	277
62	MONTANA	3026.69	1677.77	1239	2876.86	1440.17	1351
63	WAPA U.M	59.64	-79.4	129	53.95	248	-201
64	SIERRA	1287.22	1660.09	-433	1289.75	1583.81	-347
65	PACE	6438.42	6992.7	-850	5383.42	7049.99	-2036.8
70	PSCOLORA	5986.95	6910.15	-1111.7	5360.31	6550.6	-1369
73	WAPA R.M	5625.83	4029.15	1422.5	5048.28	3540.73	1339

The table above shows that the SCE and LA records in the target and source cases are fairly similar. The scheduled interchanges for both areas are also consistent. In the case of LA, there are about 200MW difference in load and generation. This is not excessive, and may only be due to the higher load and generation of LA, as modeled by SCE 2007. Nevertheless, the imports to SDG&E are also much higher in the source case. This results in much more exports from Arizona, which coincides with the SDG&E model.

Additional Records

In order to maintain the full topology of the area and avoid interchange discrepancies due to external area modeling, it was verified that all the segments of the multi-section lines were correctly incorporated in the case. The following table shows the multi-section line records passed into the target.

Table 9: Multi-Section Line Parameters

From Bus		To Bus			Parameters			Limit
#	Name	#	Name	Ckt	R	X	C	MVA
30060	MIDWAY	30063	MIDVIN21	2	0.00000	-0.00940	0.00000	1848.0
30068	MIDVIN31	30070	MIDVIN32	3	0.00054	0.01266	0.91086	3421.0
30061	MIDVIN11	30062	MIDVIN12	1	0.00110	0.02680	2.40350	2598.0
30063	MIDVIN21	30064	MIDVIN22	2	0.00110	0.02680	2.40570	2598.0
30060	MIDWAY	30061	MIDVIN11	1	0.00000	-0.00930	0.00000	1848.0
30070	MIDVIN32	30071	MIDVIN33	3	0.00058	0.01260	1.12000	3421.0
30060	MIDWAY	30068	MIDVIN31	3	0.00000	-0.00935	0.00000	1848.0

Labeling Results

As mentioned in the previous section, for the 2007 aggregation process a labeling method was utilized in order to retain power flow convergence while passing the data into the target case. In this section we summarize the resulting process of removing unlabeled records.

In the case of loads, the following records in SCE and LA did not have labels after the merging process. They were removed from the model.

Table 10: SCE and LA Loads Removed from the Target

Number	Name	ID	Status	S MW	S Mvar
25122	MTNVWAG1	1	Open	6.67	0.00
26108	MCCVIC12	1	Open	440.05	67.70
25131	MTNVWCS1	1	Open	0.00	0.00
25123	MTNVWAG2	1	Open	6.67	0.00
25124	MTNVWAS1	1	Open	6.67	0.00
25126	MTNVWBG2	1	Open	6.67	0.00
25125	MTNVWBG1	1	Open	6.67	0.00
25132	MTNVWCS2	1	Open	0.00	0.00
25127	MTNVWBS1	1	Open	6.65	0.00
25160	P160	1	Open	20.00	0.80
26109	MCCVIC21	1	Open	371.62	57.17

In the same manner, the following generators were open and then removed from the model.

Table 11: SCE and LA Generators Removed from the Target

Number	Name	ID	Status	Gen MW	Cust Float	Gen Mvar	Set Volt	Min MW	Max MW	Min Mvar	Max Mvar
24352	HIDESCT2	1	Open	0	40	0	1	0	160	-30	90
25127	MTNVWBS1	1	Closed	164.52	39	90	1	0	180	-15	90
25164	PSTRIAG3	G3	Closed	169.22	38	20.51	1	0	180	-76	105
25162	PSTRIAG2	G2	Closed	164.52	37	20.16	1	0	180	-76	105
24355	HIDESST2	1	Closed	65.81	36	17.77	1	0	86.5	-15	45
24829	WINTECX1	1	Open	0	35	0	1	0	60	-28	28
25124	MTNVWAS1	1	Open	0	34	0	1	0	180	-15	90
24720	ALTA 4GT	4	Closed	122.22	33	3	1	0	136	-60	82
25132	MTNVWCS2	1	Open	0	32	0	1	0	66	-15	30
25123	MTNVWAG2	1	Open	0	31	0	1	0	170	-15	84
24718	ALTA 3GT	3	Closed	122.22	30	3	1	0	136	-60	82
25163	PSTRIAS1	S1	Closed	173.92	29	21.23	1	0	190	-78	109
26029	HAYNES4G	1	Closed	200	28	37.41	1.02	0	222	-74	148
24351	HIDESCT1	1	Closed	141.02	27	33.15	1	0	160	-30	90
24353	HIDESCT3	1	Open	0	26	0	1	0	160	-30	90
26028	HAYNES3G	1	Closed	200	25	37.41	1.02	0	222	-74	148
25122	MTNVWAG1	1	Open	0	24	0	1	0	170	-15	84
25500	ELSEGG5	5	Closed	159.82	23	2	1.04	0	175	-60	60
24356	HIDESST3	1	Open	0	22	0	1	0	86.5	-15	45
25165	PSTRIAS2	S2	Closed	84.61	21	9.52	1	0	95	-38	53
25126	MTNVWBG2	1	Closed	159.82	20	84	1	0	170	-15	84
25131	MTNVWCS1	1	Closed	56.41	19	30	1	0	66	-15	30
25161	PSTRIAG1	G1	Closed	164.52	18	20.16	1	0	180	-76	105
24827	WINTEC8	1	Open	0	17	0	1	0	60	-28	28
25501	ELSEGG6	6	Closed	159.82	16	2	1.04	0	175	-60	60
25125	MTNVWBG1	1	Closed	159.82	15	84	1	0	170	-15	84
24830	WINTECX2	1	Open	0	14	0	1	0	60	-28	28
25502	ELSEGS7	7	Closed	258.54	13	5.28	1.04	0	280	-80	160
24354	HIDESST1	1	Closed	65.81	12	17.77	1	0	86.5	-15	45

Upon deletion of these records, the power flow solution was retained and the interchange settings brought to levels consistent to the target. The final area records of the California 2007 aggregated case are shown in Table 12. Note that the highlighted cells have the same values of the corresponding source cases.

Table 12: Area Records of California 2007 Aggregated Case

Number	Name	Gen MW	Load MW	Sched MW
10	NEW MEXI	2877.09	3312.30	-571.50
14	ARIZONA	18528.94	15144.49	3006.30
18	NEVADA	3451.55	5651.84	-2267.10
19	WAPA L.C	3753.08	138.30	3430.00
20	MEXICO-C	2332.72	2308.90	0.00
21	IMPERIAL	968.37	790.00	155.60
22	SANDIEGO	1997.29	4733.18	-2848.20
24	SOCALIF	16382.45	22037.83	-6079.00
26	LADWP	5262.60	6269.12	-1494.10
30	PG AND E	24791.61	25586.54	-1887.80
40	NORTHWES	32130.03	26650.33	4251.00
50	B.C.HYDR	10884.48	6973.68	3300.00
52	W KOOTEN	672.94	752.47	-100.00
54	ALBERTA	8927.27	8721.00	-200.00
60	IDAHO	4366.66	3245.00	891.00
62	MONTANA	3024.72	1677.77	1239.00
63	WAPA U.M	59.64	-79.40	129.00
64	SIERRA	1286.20	1660.09	-433.00
65	PACE	6428.53	6992.70	-850.00
70	PSCOLORA	5984.65	6910.15	-1111.70
73	WAPA R.M	5611.97	4029.15	1422.50

Electronic Display

As part of the case aggregation for 2007, the previously created diagram for 2005 was adjusted to fully reflect the consolidated case. This adjustment included the modifications of about 20 buses and the elements connected to them, such as transmission lines and transformers, as well as graphical objects that support visualization of the power flow solution. This resulted in updating about 230 graphical objects. PowerWorld is delivering this fully integrated diagram with the 2007 aggregated case.

Conclusions

PowerWorld has followed a detailed, technically sound, data handling and power flow case creation process to obtain a consolidated case that represents the California electric system for the 2007 summer peak.

The PG&E data was obtained by scaling the Area 1 2007 case to reflect the load growth after the Area 7-8 models. The aggregated case also models SDG&E and SCE exactly as they were modeled in the source cases provided by each one of these utilities. To complete the California case, LADWP was modeled after the SCE source, and Imperial was modeled after the PG&E case.

PowerWorld is confident that the consolidated case for California 2007 is robust enough to support extensive contingency analysis, hot spot identification, and WTLR calculations, as well as additional system scaling to model the years considered in this project.

PowerWorld has also modified the electronic diagram of California to fully match this aggregated case, and is being delivered as part of this aggregation task.

APPENDIX B: 2010 and 2017 Official Run Report: Development of the Summer Peak Cases

Executive Summary

This document describes PowerWorld and Davis Power Consultant activities related to the development of cases for the summer peaks of 2010 and 2017. These cases will be subject to contingency and hot spot analysis, as well as renewable resource interconnection studies.

The goal of the aggregation processes was to obtain a single case for each year that represents an informed estimate of how each utility would manage their control areas, and that would allow the determination of hot spots, weighted transmission loading relief (WTLR) sensitivities, and the development of scenarios for renewable energy penetration. The forecast contained in the California Energy Commission Preliminary Renewable Resource Assessment was used as an estimate for peak summer load growth. The data of energy growth for the 10-year period from 2007 through 2017 was converted to MW demand growth over the same period.

The 2007 summer peak case developed in a previous task of this project was used as the base for load scaling and generation additions for the 2010 and 2017 cases. The 2007 case has the advantage of being an aggregate case that considers utility company models and provides a robust platform for hot spots and potential generation expansion solutions.

The 2010 and 2017 case development process consisted of two phases. In the first phase, known transmission and generation expansion projects were incorporated and loads were scaled. In the second phase, slight adjustments were made to unit commitment and transmission services to enable the power flow solution and improve the reliability and security of the system. These changes are consistent with standard operating procedures that would mitigate normal operation violations and ensure a secure system.

Background: Data Availability and Handling

This section discusses the data availability from each control area in California and describes the source cases utilized during the 2010 and 2017 case development. The resulting power flow models capture the transmission constraints and operating practices for the summer peak.

An initial attempt was made to match the data provided by the CALIFORNIA ENERGY COMMISSION Electricity Infrastructure Assessment, which contains generation profiles based on standard operating practices up to 2012. The process to develop the power flow case consisted of loading the production costing data in the power flow model and progressively adjusting generation and interchange settings to match the assumed scheduled interchanges and area losses. However, the proposed levels of generation, which were not based on solved power flow models, were not achievable when implemented in the transmission model. The system presented voltage stability problems during normal operation, which are an indicator of discrepancies in the input data. Trending analysis was developed in an attempt to validate the data provided by the production costing model. The trends however confirmed inconsistencies in the modeling approach of non-peak technologies that would prevent the power flow model from accurately reflecting the generation mix for the summer peak. Consequently, the production costing model was abandoned as a source of reliable data for the development of the 2010 and 2017 cases.

Given the limited power flow data available beyond 2007, it was necessary to refer to the forecast provided by the CALIFORNIA ENERGY COMMISSION Preliminary Renewable Resource Assessment Report, which proposes a scenario for target renewable energy projects by 2005, 2008 and 2017. The report also describes a set of preliminary projects that could be considered in order to achieve the target penetration, and provides detailed energy forecasts for the California utilities. It was determined that this forecast data, along with known generation and transmission expansion and the 2007 aggregated model developed in a previous task of this project, would provide a more accurate model of the California power system for the 2010 and 2017 summer peaks.

System Scaling for 2010 and 2017

This section describes the scaling process for the statewide and WECC control areas. This process was based on the 2007 peak summer demand reported by the major utilities and the energy growth rates in the CALIFORNIA ENERGY COMMISSION Preliminary Renewable Resource Assessment Report. For the 2007 aggregate summer peak model, each utility submitted 2007 summer peak cases. The development of the aggregate case is described in Development of the Aggregated Case for California 2007: Final Report. No utility cases were available for years following 2007.

Power System Scaling

Power system scaling is the process of modifying a similar set of variables in the power system in order to achieve a model that represents a new condition. Scaling is generally related to loads, the driving variable of power system resource analysis, operation, and control.

Area load scaling is performed when there is no information regarding forecast at the bus level. Utilities are able to obtain system load forecast data, production costing studies for a set of scenarios, and a power flow case that can be used as a base for the scaling process. The standard scaling approach utilized for this study includes the following considerations:

- Definition of the control area(s) to be scaled: California, plus external WECC areas
- Proportional scaling of active power load
- Scaling of reactive power load to keep constant power factor
- Proportional scaling of generation based on participation factors to keep area control error (ACE) constant

The process is complete when a successful solution of the AC power flow problem is achieved. Note than in general, the positive scaling of control area loads will ultimately be limited by voltage collapse (loading margin) for normal operation. It is expected that the validity of the system scaling decreases as the scaling multiplier increases. For voltage collapse, a 10 to 20 percent scaling is usually achievable without transmission expansion in a well-conditioned power system.

Load Scaling from the 2007 Model

The CALIFORNIA ENERGY COMMISSION Preliminary Renewable Resource Assessment provides estimated retail sales of energy for years 2001 through 2017. Table 1 shows those figures for 2007 and 2017 and the compound annual growth rate for the 10-year period.

Table 1: Estimation of Statewide Energy Requirements

Year	Sales (GWh)	Compound Annual Growth Rate
2007	264,276	
2017	304,896	1.44%

The three California investor owned utilities, the Los Angeles Department of Water and Power (LADWP), and the Imperial Irrigation District (IID) provided expected peak load served for 2007, which were used to compile the 2007 California Aggregated Case.

Assuming a constant load factor and constant rate of area interchange for the forecast period, the compound annual growth rate from Table 1 can be applied to the summer peak load in the 2007 California Aggregated Case to estimate the summer 2010 and 2017 peak loads for each control area. This method provides area load estimates based on a consistent set of assumptions and may be applied to other intermediate years as needed. The load estimates are summarized in Table 2.

Table 2: Summer Peak Load Estimation

Num	Area Name	2007 Load MW, California Aggregated Case	2010 Load MW	2017 Load MW
21	IMPERIAL	790.0	824.6	911.4
22	SANDIEGO	4,733.2	4,940.6	5,460.7
24	SOCALIF	22,037.8	23,003.6	25,425.0
26	LADWP	6,269.1	6,543.8	7,232.7
30	PG AND E	25,586.5	26,707.8	29,519.1
	Subtotal Statewide	59,416.6	62,020.4	68,548.9
	Rest of WECC	94,088.7	98,211.9	108,550.0
	Total	153,505.3	160,232.3	177,098.9

Generation and Transmission Additions

CALIFORNIA ENERGY COMMISSION indicated the need to include in the power flow model additional generation and transmission expansion that have been approved during the last year. These projects were not included in the 2003, 2005 and 2007 summer peak deliverables. They will be on-line in 2010 and should be modeled in the 2010 and 2017 cases. Details of new generators are listed in the following table.

Table 3: New Generation Projects

Generator Records							
Area #	Area Name	Bus #	Bus Name	ID	Type	Status	MW
19	WAPA L.C	19322	BLYENG1	1	Unknown	Closed	173
19	WAPA L.C	19323	BLYENG2	1	Unknown	Closed	173
19	WAPA L.C	19324	BLYENG3	1	Unknown	Closed	173
21	IMPERIAL	21093	Saltonse	1	Other	Closed	185
22	SANDIEGO	22605	OTAYMGT1	1	Gas	Closed	172
22	SANDIEGO	22606	OTAYMGT2	1	Gas	Closed	172
22	SANDIEGO	22607	OTAYMGT3	1	Gas	Closed	214
TOTAL	1262						

The incorporation of these generation projects requires transmission expansion to avoid normal operation violations and local contingency violations. The expansion is summarized in Tables 4 and 5.

Table 4: New Buses in the System

Bus Records				
Bus #	Bus Name	Area #	Area Name	Nom KV
21092	Banster	21	IMPERIAL	161
21093	Saltonse	21	IMPERIAL	161

22605	OTAYMGT1	22	SANDIEGO	18
22606	OTAYMGT2	22	SANDIEGO	18
22607	OTAYMGT3	22	SANDIEGO	16
22609	OTAYMESA	22	SANDIEGO	230

Table 5: New Transmission Lines and Transformers

Branch Records									
F#	From Name	T #	To Name	Ckt	Xfrm	R	X	C	Rating
19020	BLYTHE	19101	BUCKBLVD	2	No	0.0000	0.00050	0.00000	400.0
19020	BLYTHE	21047	NILAND	2	No	0.0499	0.18900	0.08340	171.5
19020	BLYTHE	21047	NILAND	3	No	0.0834	0.04990	0.18900	171.5
19020	BLYTHE	24017	BLYTHESC	2	No	0.0000	0.00050	0.00000	168.0
20149	TJI-230	22609	OTAYMESA	1	No	0.0203	0.00050	0.00520	797.0
21003	AVE58	21092	Banster	1	No	0.0566	0.03240	0.12580	171.0
21026	ELCENTSW	21027	ELSTEAMP	2	Yes	0.0000	0.06400	0.00000	125.0
21047	NILAND	21048	NILAND	2	Yes	0.0000	0.09333	0.00000	75.0
21047	NILAND	21048	NILAND	3	Yes	0.0000	0.09333	0.00000	75.0
21059	PILOTKNB	21061	PILOTKNB	2	Yes	0.0000	0.06400	0.00000	75.0
21092	Banster	21026	ELCENTSW	1	No	0.0566	0.03240	0.12580	171.0
21093	saltonse	21047	NILAND	1	No	0.0453	0.02590	0.10060	200.0
21093	saltonse	21092	Banster	1	No	0.0453	0.02590	0.10060	200.0
22464	MIGUEL	22609	OTAYMESA	1	No	0.0340	0.00080	0.00880	796.0
22609	OTAYMESA	22605	OTAYMGT1	1	Yes	0.0000	0.00107	0.02655	250.0
22609	OTAYMESA	22606	OTAYMGT2	1	Yes	0.0000	0.00107	0.02655	250.0
22609	OTAYMESA	22607	OTAYMGT3	1	Yes	0.0000	0.00067	0.01712	311.0

Additional Changes Prior to Contingency Analysis for 2010

New generation and transmission additions and load scaling may introduce complications in the power system, which need to be resolved. These may include base case violations, high or low voltages, or lack of area generation reserves. After load scaling and generation additions took place, the system had a small number of base case violations and localized high voltages. Base case thermal violations were removed where possible by re-dispatching generators in the California control areas, and high voltages were resolved by switching capacitor banks.

The generation at FCNGEN units at buses 14911 and 14912 were reduced from 169 to 100 MW in order to reduce slight violations in WAPA. Generation at PS-BEAR, 35066 was reduced from 57.85 to 45 MW to remove a base case overload in the line directly connecting the unit. The generation at ULTR RCK, 32412 was increased from 15.26 to 18MW in order to remove a base case overload in 32412ATLANTIC to 30335ATLANTC. The shunt CSCDE at 31795 was opened to correct high voltage in the region.

Further Changes Prior to Contingency Analysis for 2017

All the changes incorporated in the 2010 case were utilized in the development of the 2017 case. As illustrated in Table 2, the demand in 2017 is considerably higher than in the previous years. A limitation of the current power flow model is that if generation maximum output is to be enforced, then the load scaling may force spinning generation reserves to zero.

The process to match the 2017 load target was to incrementally scale areas outside and inside California up to the target value. We determined that it was not possible to simultaneously maintain the area interchange settings and reach the target load scale value for areas outside California. The load of non-California control areas was limited to 3% less than the target value. This however is close enough to obtain reasonably accurate flow in the area tie lines and inside the California areas. In SCE and SDG&E, the load plus losses plus the scheduled interchange exceeded the amount of spinning reserves. Thus some generation needed to be committed in the model. The reconnected generation is listed in Table 6.

Table 6: Generators Reconnected in the 2017 Case

Reconnected Generation							
Area #	Area Name	Bus #	Bus Name	ID	GenMW	SetVolt	MaxMW
24	SOCALIF	24740	MCGEN	1	100.00	1.03	108.00
24	SOCALIF	24458	ENCANWND	1	100.00	1.01	112.90
22	SANDIEGO	22074	LRKSPBD1	1	49.00	1.05	49.00
22	SANDIEGO	22075	LRKSPBD2	1	49.00	1.05	49.00
24	SOCALIF	24054	MTNVIST5	5	100.00	1.03	126.00
22	SANDIEGO	22376	KEARN3CD	2	14.00	1.00	14.00
22	SANDIEGO	22377	KEARNGT1	1	14.00	1.00	15.00
22	SANDIEGO	22375	KEARN3AB	1	14.00	1.00	15.00
22	SANDIEGO	22257	RAMCO_ES	1	49.00	1.01	49.50

Because of the high stress placed on the transmission network with the 2017 loading, some limit monitoring settings were changed to focus the contingency analysis and the weighted overload on the most significant problems. Several lines that were monitored in the 2010 contingency analysis were not monitored in the 2017 contingency analysis. Most of these were either nearly overloaded or slightly overloaded in the 2017 reference case and would have skewed the weighted overload results if monitored. Details of those lines are shown in table 7.

Table 7: Transmission Lines Not Monitored

Transmission Lines Not Monitored in 2017 Contingency Analysis								
From Area Name	From Number	From Name	To Area Name	To Number	To Name	Ckt	Xfr	% of Limit
WAPA L.C	19038	MEAD	LADWP	26044	MARKETPL	1	No	94.7
SANDIEGO	22256	ESCNDIDO	SANDIEGO	22008	ASH	1	No	105.5
SOCALIF	24350	HIDESERT	SOCALIF	24601	VICTOR	1	No	111.8
SOCALIF	24403	BAILEY	SOCALIF	24115	PASTORIA	1	No	92.8
SOCALIF	24728	INYO	SOCALIF	24730	INYO PS	1	Yes	114.8
SOCALIF	24807	MIRAGE	SOCALIF	24821	TAMARISK	1	No	106.3
PG AND E	30419	CR1T4_23	PG AND E	30430	FULTON	1	No	131.9
PG AND E	30640	TESLA F	PG AND E	30655	ADCC	1	No	106.2
PG AND E	30655	ADCC	PG AND E	30631	NEWARK E	1	No	106.2
PG AND E	32104	DAVIS	PG AND E	31990	DAVIS	4	Yes	110.1
PG AND E	32412	ATLANTIC	PG AND E	30335	ATLANTC	1	Yes	104.1
PG AND E	32664	IGNACO A	PG AND E	30446	IGNCIO M	3	Yes	143.5
PG AND E	32666	IGNACO B	PG AND E	32568	IGNACIO	1	Yes	65.2
PG AND E	37505	KESWICK	PG AND E	37947	SULP CRK	1	No	104.6

Seasonal Case Development

Spring and winter cases for 2010 and 2017 were not developed for contingency and hot spot analysis in this phase of the project. A 2003 WECC spring case was available as a possible basis for modeling future seasonal cases. However, there are several impediments to conducting a credible analysis for relieving congestion using seasonal cases. Bus compatibility between models, implementation of generation mix, and the solvability of seasonal production costing models present issues that cannot be resolved.

First of all, there is significant incompatibility between the bus identification schemes used by the WECC and those utilized in the aggregate cases developed as part of this project, which considered the exact bus numbering scheme utilized by each utility. It is difficult to reconcile the models and the electrical elements contained within them, both in terms of the network topology and the geographic location of the elements. The GIS data used by the CDF is compatible the summer cases provided by the CALIFORNIA ENERGY COMMISSION, but not fully compatible with the WECC seasonal cases.

Furthermore, the amount of scaling required between the 2003 spring and 2010 spring cases would be significant. No analysis is available to enable identification of unit commitment or area interchange schedules beyond 2003, thus identification of weak elements for 2010 and 2017 seasonal cases would be suspect. Because the generation mix is different for the seasonal cases, it is also not practical to scale the 2010 and 2017 summer cases to match seasonal loads.

The Electricity Infrastructure Assessment Report contains scenario data that could be utilized for developing seasonal cases. However, as mentioned in Section 2 of this report, the data provided by the production costing model could not be validated by power flow solutions. The data for the spring of 2005 was tested in the power flow model, which reported discrepancies that could not be resolved. In particular, the expected spring area interchange levels could not be met without driving the power flow to an unsolvable region. This further supports the need to validate production costing models with power flow simulations. This would require a major effort that falls outside the scope of this project. Consequently, it was concluded that there was not enough data available that would enable the development of realistic seasonal cases for 2010 and 2017.

The summer cases represent the greatest stress on the transmission network, and thus are most appropriate to study for congestion relief. Summer conditions represent the highest level MW overload and drive network planning decisions. The seasonal case analysis would not contribute significantly to the identification of weak elements. As a result, the hot spots identified under summer conditions and maximum output of the studied plants represent the best places for siting new generation to relieve congestion.

While some renewable resources may have higher capacity in the spring and winter than in the summer, the lower summer output will still make an impact on relieving weak elements when they are most overloaded. The WTLR and MW injection data show that small levels of injection at properly identified hot spots provide significant relief of weak elements. Any level of renewable generator output will be beneficial if sited at locations with high summer WTLR.

Conclusions

PowerWorld has followed a detailed, technically sound, data handling and power flow case creation process to obtain a consolidated case that represents the California electric system for the 2010 and 2017 summer peaks.

PowerWorld has validated the cases and determined they are robust enough to support contingency analysis, hot spot identification, WTLR calculations, and the renewable resource interconnection studies to be considered in this project.