Arnold Schwarzenegger
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PIER FINAL PROJECT REPORT

INTERMITTENCY ANALYSIS PROJECT: APPENDIX A INTERMITTENCY IMPACTS OF WIND AND SOLAR RESOURCES ON TRANSMISSION RELIABILITY

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Executive Summary

The California Energy Commission (Energy Commission) recognizes the need driven by the Renewables Portfolio Standard goals of the state's utilities to study the potential effects that a high penetration of intermittent resources such as wind and solar has on the security and reliability of the transmission grid. The Intermittency Analysis Project investigates the transmission impacts of high penetration of intermittent resources such as wind and concentrated solar power on transmission adequacy and system security for different years, seasons, and penetration levels. Davis Power Consultants, Power World Corporation, and Anthony Engineering completed this part of the Intermittency Analysis Project, a comprehensive statewide examination of the potential grid and transmission effects of high levels of intermittent renewable resources.

Transmission and generation expansion are planned in a coordinated manner to ensure generation resource adequacy and to maintain or improve transmission grid security and reliability. Transmission grid security and reliability are determined by the amount and severity of transmission overload that is caused by new renewable projects during normal and contingency operation.

The goals of the Intermittency Analysis Project transmission study are to: (1) develop a method to evaluate the potential effects of intermittent resources on the transmission grid; (2) define a planning process by which conventional and renewable resources can be analyzed; and (3) develop a common framework that can be used by agencies, utilities, and developers to plan renewable and conventional resources that continue to support a reliable transmission grid. The analytical process developed for the Intermittency Analysis Project transmission study tests the impacts of intermittently available and variable output supply resources and the special challenges that these resources place on the system planner. Using the techniques developed by Davis Power Consultants, planners can locate regions or bus groupings within the system that are particularly vulnerable to variable inputs (load or generation.) These techniques provide a consistent and verifiable method of defining the costs and benefits of various transmission projects.

When a new wind resource is completed and connected to the grid, its output creates a time-variant power injection into the network. This new project, depending on its capacity, may require transmission expansion to maintain security. The transmission expansion required depends on:

- The location of the project (the bus where the power is injected).
- The size of the project (the maximum amount of megawatt [MW] injection).
- The generator output and load profile, which determines the existing or base case flows in the grid, and that are a function of time (peak or non-peak hour, season).
- The intermittency of the output function (how many hours the injection is above a certain MW level) for the project itself and for other intermittent resources throughout the system.

The Intermittency Analysis Project transmission study focused on the following objectives:

- Identify anticipated transmission congestion locations.
- Evaluate transmission and other grid improvements required to accommodate 2010 and 2020 renewable resources.
- Provide contiguous data sets for statewide transmission planning and evaluation.
- Develop analytical tools and methods that would enhance the system planner's ability to incorporate least-cost-best, fit renewables into transmission grid reliability assessment.
- Foster a collaborative planning process among stakeholders.

Before studying the effects of intermittent renewables on the California transmission system, the Intermittency Analysis Project transmission team developed the evaluation process, illustrated in Figure 1-1, consisting of the following five steps:

- Step 1: Transmission Data Collection and Base Case Development.
- Step 2: Development of Study Cases and Renewable Mix Development.
- Step 3: Hourly Intermittency Analysis.
- Step 4: Maximum Renewable Penetration Analysis.
- Step 5: Wind and Load Correlation Analysis.

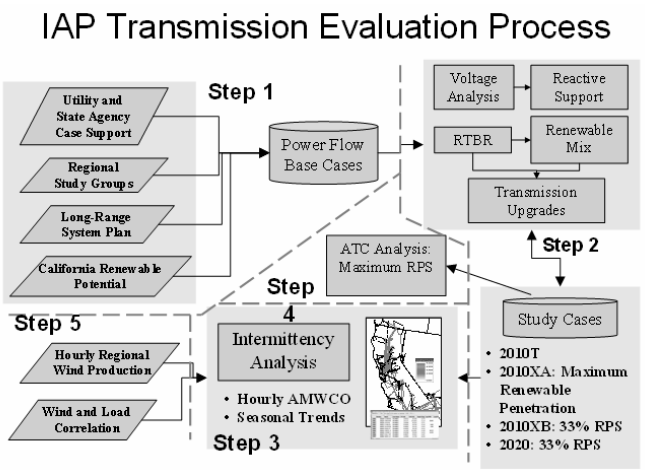

Figure 1-1: Intermittency Analysis Project Transmission Evaluation Process

Power flow models are compiled representing system load, conventional generation, and hydro dispatch patterns for projected summer peak, spring peak, and fall off-peak periods. California utilities and several working groups provide seasonal cases based on Western Electricity Coordinating Council models and supplemental data from which base cases for the years of interest are compiled. The Energy Commission's statewide load forecasts are applied to create base cases for each season in 2010 and 2020. Four sets of renewable power flow cases are developed as follows:

- 2010 Tehachapi or 2010T: Includes 3,000 MW of wind capacity at Tehachapi and additional renewable capacity to supply 20 percent of energy from renewable resources.

- 2010 XA: Similar to 2010 Tehachapi, but with the maximum level of simultaneous renewable generation that the 2010 system models can support without adding new transmission.
- 2010 XB: Includes 4,500 MW of wind capacity at Tehachapi and additional renewable resources and transmission to supply 33 percent of energy from renewable resources.
- 2020: Similar to 2010 XB, but with additional capacity to supply 33 percent of the projected 2020 energy requirements from renewable resources.

The previous Energy Commission Strategic Value Analysis study and *2005 Integrated Energy Policy Report* (IEPR) developed the type, size, and location of the least-cost, best-fit renewable resources required to meet the energy targets. The Strategic Value Analysis process identified locations with resource availability that maintained or enhanced system security wherever possible.

Additional direction concerning the characteristics of some specific renewable projects, such as the Tehachapi wind development, is provided through the collaborative process. Transmission upgrades are added to each case to relieve transmission overloads under normal operating conditions. Combining the seasonal base cases with the renewable mixes and transmission upgrades yields a set of study cases used to analyze the effects of intermittent resources on transmission security. The projected renewable mix for the 2010 20 percent and the 2020 33 percent penetrations are shown in Table 1-1.

Table 1-1: Projected Renewable Mix

Renewable	2010T (MW)	2010T (GWh)	2010T Energy	2020 (MW)	2020 (GWh)	2020 Energy
Wind	5,035	16,319,442	55%	10,138	32,669,018	46%
CSP	946	2,237,479	8%	2,700	6,386,040	9%
Residential PV	533	933,816	3%	2,860	5,010,720	7%
Biomass	221	1,742,364	6%	990	7,746,906	11%
Geothermal	1,064	8,388,576	28%	2,385	18,803,340	27%
Total	7,799	29,621,677	100%	19,073	70,616,024	100%
Energy Target		28,969,000			70,678,509	

2010T = 2010 Tehachapi; GWh = gigawatt-hours

Using the basic renewable mix above, the system security of the study case is analyzed with non-variable production from normally intermittent wind and solar powered generators to establish a baseline for later comparison of varying production. The system *aggregate MW contingency overload* metric provides a measure of security by totaling the amount of transmission overloading in California resulting from all single transmission element or generator (N-1) contingencies (approximately 7,000 total). The change in security resulting from each proposed renewable project using the *renewable transmission benefit ratio* is analyzed. The

renewable transmission benefit ratio measures the improvement in system aggregate MW contingency overload [1] contributed by each renewable project, per MW of generation.

Figure 1-2 shows the renewable transmission benefit ratios for the 2010 renewable resource mix (developed from wind data listed in Table 5-7.) Negative values indicate that renewable transmission benefit ratio improves transmission reliability by reducing the aggregate MW contingency overload. There are only a few renewables locations that have positive values. For many locations, the renewable transmission benefit ratio values change in magnitude and sign by season.

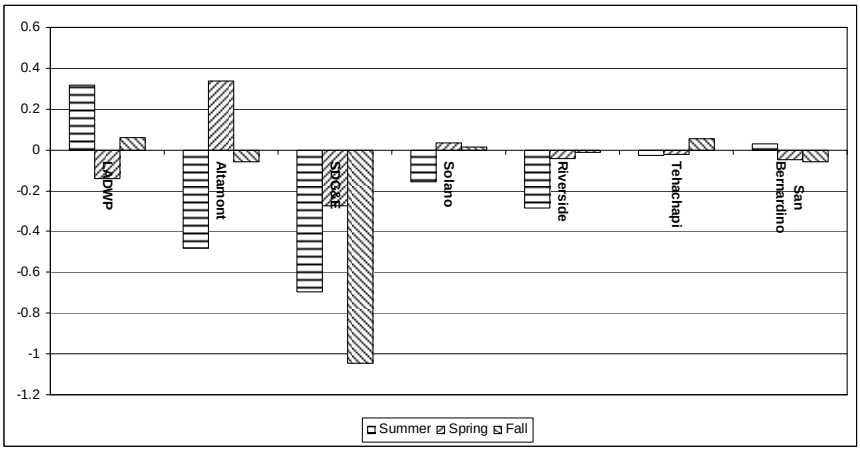

Figure1-2: 2010 Renewable Mix RTBR[2]

When the 2010 XB case is developed from the 2010 Tehachapi case by increasing the renewable penetration from 20 percent to 33 percent, voltage stability analysis is completed to determine where reactive compensation is needed to support system voltage. The 2010 XB case requires only two capacitor bank additions to improve bus voltages in weak parts of the system. A total of 250 M VAR is added to the 2010 XB system model to support the 2010 load profile and 33 percent renewable energy target.

In contrast, Figure 1-3 shows the renewable transmission benefit ratios for the 2020 renewable mix (developed from wind data listed in Table 1-1). There are more renewables in the three seasons where the renewable transmission benefit ratios are positive. A positive renewable transmission benefit ratio by itself does not mean that the project cannot provide net benefits to system operation. Transmission upgrades or operational *remedial action schemes*, including the effective redispatch of responsive conventional generation, may reduce adverse renewable transmission benefit ratio locations observed in the study.

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1 Refer to references section for report(s) detailing the renewable transmission benefit ratio and aggregate MW contingency overload.

2 Riverside is the same wind site as San Gorgonio.

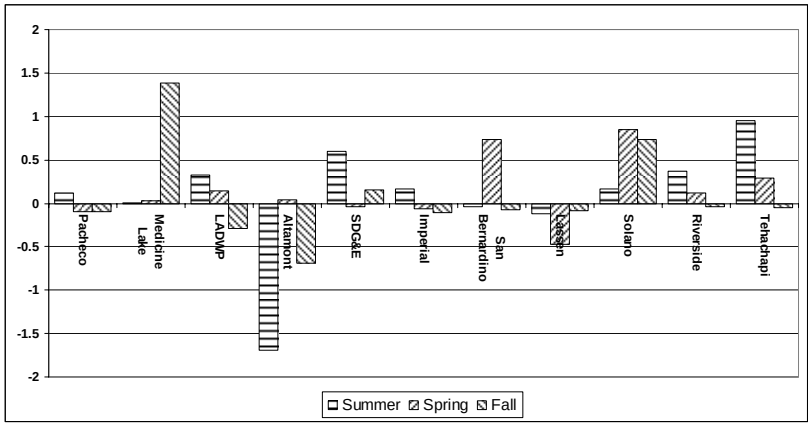

Figure 1-3: 2020 Renewable Mix Renewable Transmission Benefit Ratio

As system load increases with the 2020 scenarios, voltage stability analysis is completed to determine where reactive compensation is required to support system voltage. Several capacitor banks improve bus voltages in weak parts of the system and allow the simulation of variable production from intermittent wind-powered generators[3]. A total of 1,860 megavolt-amperes reactive of reactive compensation is needed (12 percent increase of existing static or dynamic shunt mega voltage-ampere reactive injection) to maintain system voltage in the 2020 system, while increasing renewable generation to support the 33 percent renewable energy target.

In the 2010 Tehachapi case a 20 percent penetration and associated transmission expansion is represented, with excess transmission capacity available to increase the penetration above 20 percent. This occurs since transmission is installed in set increments of capacity dictated by standard wire size. As part of the Intermittency Analysis Project study, *available transfer capability* analysis is applied to determine the excess transmission capacity available to deliver additional renewable generation to the system. In the available transfer capability analysis, all renewable units in the 2010 Tehachapi summer peak case are increased simultaneously and non-varying, in proportion to the capacity of each unit, until reaching the limits of the transmission system. The penetration increases from 20 percent to 26 percent. As a check, the renewable mix is manually adjusted until a maximum penetration is reached. Rather than increasing output of each unit simultaneously, the manual method dispatches each renewable project sequentially to its maximum capacity in order of increasing renewable transmission benefit ratio, so that projects with the most transmission benefit are increased first. However, the manual method yielded only a 23 percent penetration.

Wind intermittency requires the transmission system to be capable of supporting a variety of wind generation patterns, as variable regional wind production gives rise to variable power transfers across the system. The variable wind conditions are simulated for each of the seasonal

3 A power factor of 0.97 is used to represent the voltage-ampere reactive output capabilities of the wind generators.

study cases with historical regional hourly capacity factors provided by the California Independent System Operator (California ISO).

The forecasted hourly wind data was not available for the transmission study of intermittent resources. Using the 2004 historical wind production data represented by five major wind regions, the California wind regions from the 2010 Tehachapi and 2020 cases are assigned to one of the five existing wind regions shown in Figure 1-4. As such, the transmission results may have some bias due to the limited data. For example, all the wind sites south of San Gorgonio are assigned the same hourly wind pattern as San Gorgonio. This may result in less realistic wind variation as all wind units in the same region will be following the same output pattern, as opposed to each unit having its own pattern. However, the method developed to study intermittent resources is still useful for indicating transmission system concerns from the regional wind variation.

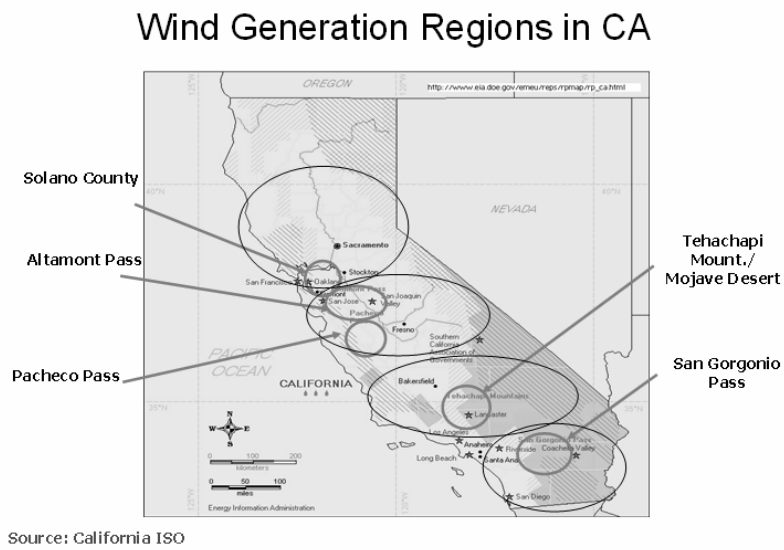

Figure 1-4: Wind Generation Regions

The results of the hourly intermittency simulation reveal several instances of transmission congestion influenced by specific wind production patterns. The study team recorded notable correlations between regional wind production and the degree of overloading observed on transmission lines and transformers. Several transmission paths present frequent overloading that varies with regional wind production across seasons and renewable scenarios:

- The Proposed Tehachapi – Midway 500 kilovolt (kV) upgrade exhibits overloading on a series capacitor during periods of high Tehachapi production. If bypassing the capacitors during periods of high loading is not operationally feasible, the capacitors should be sized to handle the rated load of the transmission lines served.
- The high voltage transmission lines north of Midway experience various levels of transmission overloads depending on the season and the wind generation. The lines tend to have overloads during the fall seasons of various durations depending on the wind

generation from Tehachapi, Solano, and Altamont. When Solano and Altamont are low and Tehachapi high, there are more transmission problems.

- The Vaca Dixon - Peabody 230-kV line exhibits extreme loading variability and vulnerability to thermal overloads under contingencies across seasons, especially in the 2010 XB and 2020 scenarios.
- The California Oregon Intertie and 500-kV paths south of the Interie are vulnerable to thermal overloads during periods of high Northwest imports. Variable wind production imparts some variability to the level of contingency overloading on the Intertie as other resources are dispatched during periods of low wind.
- The low voltage collector network in the Altamont region may require upgrades if circuit breaker operation and other remedial action schemes (for example, dropping load or branch switching) are unable to alleviate overloading observed during periods of low Altamont wind production.

The fall simulation reveals base case overloads on the 500-kV network throughout all of California, even on the Tehachapi upgrades, though such overloads are confined to periods of peak Tehachapi production and low Altamont and Solano production. Such patterns create abnormally high south-to-north flows through Midway, Los Banos, and Tracy, unless additional transmission upgrades are made, wind production is curtailed, or additional gas units are dispatched in the north to counter the effect. Highly sensitive to Tehachapi wind production is a series capacitor on the planned 500 kV Tehachapi – Midway circuit.

Under contingency analysis, a few hours of extremely high hourly system aggregate MW contingency overload occurs during a period of unusually high Tehachapi production, which coincides with low wind production in Northern California. The proposed Tehachapi – Midway 500 kV circuit overloads under contingencies, as in the base case. The line includes a modeled capacity of 1,848 megavolt-amperes limited by one of its series capacitors. The capacitor rating may be inadequate to support some wind patterns, unless conventional resources in Northern California are dispatched to sufficiently offset south-to-north flows or unless the capacitors are bypassed during heavy loading. The contingency rating of the proposed transmission line itself is 2,567 megavolt-amperes.

The addition of new renewable resources requires new transmission lines, transmission line upgrades, transformer upgrades, and new substation transformers. The 20 percent and 33 percent penetrations cannot be realized with the renewable locations selected for the Intermittency Analysis Project study if the new transmission elements are not developed. To meet the 2020 33 percent renewable penetration, 128 new or upgraded lines and 40 transformers are needed, at an estimated current dollar cost or more than $6 billion for only part of these estimated upgrades.

In addition to the transmission upgrades, the variability caused by greater reliance on intermittent resources may require mitigation with special protection schemes that limit the magnitude of hour-to-hour changes in wind production or curtail wind if production exceeds the capacity of the transmission network to deliver wind energy to the load. As much as

possible, fast-responding load-following resources such as simple -ycle gas turbines could be needed and be strategically redispatched by region in response to varying wind conditions.

The Intermittency Analysis Project transmission study reveals that as renewable penetration subsequently increases with the 2010 Tehachapi, 2010 XB, and 2020 scenarios, the variability of transmission loading and contingent overloading generally increases as well. However, except during the summer 2020 peak, the average system security level generally improves with increasing renewable penetration. The benefit is a reflection of the positive locational value of the incrementally added renewable generation. However, the steady increase in line loading variability suggests that operational flexibility of the system must keep pace with intermittent resource penetration to maintain system security into the future. The extreme loading of the summer 2020 simulation offsets the net locational benefits of the additional renewable resources. Additional transmission upgrades and the evolution of operational remedial action schemes are required to maintain system security into 2020 while achieving the 33 percent renewable energy target.

1.0 Introduction

Transmission and generation are planned in a coordinated manner to ensure generation resource adequacy and to maintain or improve transmission grid security. In this report, transmission grid security refers to the amount and severity of transmission overload caused by new renewable projects.

When a new wind generation project is connected to the grid, it creates a time-variant (intermittent) power injection to the network. The new project may require transmission expansion to avoid introducing new transmission grid security problems. The requirement for transmission expansion depends on:

- The location of the project (the bus where the power is injected).
- The size of the project (the maximum amount of megawatt [MW] injection).
- The time-varying generation and load profile (peak or non-peak hour, season, etc.), which determines the power flow on the grid.
- The intermittency of the wind generation (how many hours its output is above a certain MW level) and intermittency of other resources throughout the system.

Projects which frequently overload transmission elements may require transmission expansion or upgrade. Such overloads may be present during normal operating conditions or contingencies. The requirement for transmission expansion may render a project unattractive. However, injections at some locations may improve transmission grid security.

The objective of the Davis Power Consultants[4] portion of the Intermittency Analysis Project (IAP) study is to develop a methodology to determine the impact of intermittent resources on the transmission system under various renewable penetration levels, seasons, and future years. The renewable penetration levels are based on a percentage of the total energy sales by California utilities. The levels of interest are 20% by 2010 and 33% by 2020.

The IAP study provides a methodology for evaluating the transmission impacts and benefits of intermittent and conventional resources. The methodology augments the existing utility transmission planning process, although regulators and developers could also use it as a stand-alone analysis tool.

The IAP study methodology provides simple metrics of expected overall transmission grid security with intermittent resources, given fixed system load, imports, and dispatch of hydro-electric and base-load generating units. As such, it can serve as a screening tool to compare renewable alternatives, conventional resource alternatives, and transmission expansion alternatives, and to eliminate those that do not meet least-cost, best-fit criteria or do not improve transmission grid security.

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4 DPC refers to the DPC team of Davis Power Consultants, PowerWorld Corporation and Anthony Engineering.

A planner can also use the IAP study methodology with a power flow model to evaluate voltage stability and site-by-site and state-wide system benefits. The benefits are particularly important as o*ptimal power flow* (economic dispatch subject to transmission constraints), California Independent System Operator (California ISO) congestion zones, and market redesign and technology upgrade (MRTU) can be incorporated into the IAP process. Optimal power flow can be used to study (1) how other variables (e.g., fuel and operating costs) impact transmission grid security and (2) adjustments made to increase flexibility to accommodate intermittent resources. Finally, the IAP study methodology provides informative summary graphics for presentations and reporting.

2.0 IAP Methodology for Evaluating Transmission Impacts of Intermittent Resources

The DPC team developed the transmission evaluation process shown in Figure 2-1 to guide the study of renewable intermittency impacts on the California transmission system.

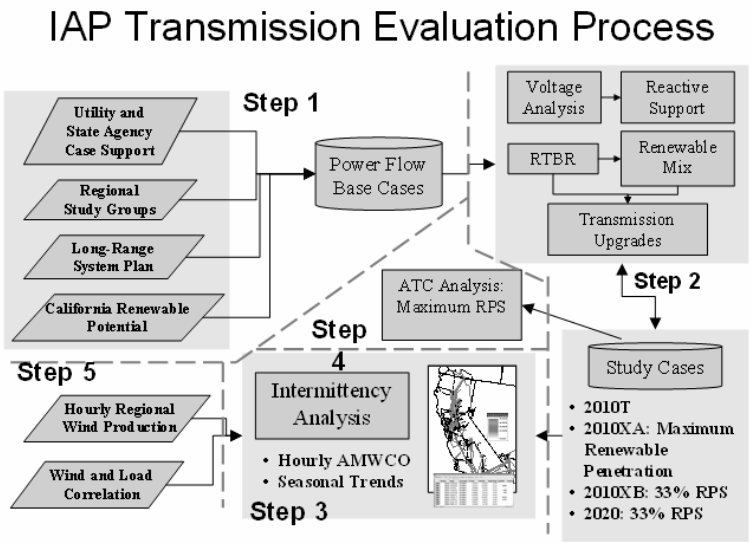

Figure 2-1: IAP Transmission Evaluation Process

The five-step transmission evaluation process consisted of:

- Step 1: Transmission Data Collection and Base Case Development.
- Step 2: Development of Study Cases and Renewable Mix Development.
- Step 3: Hourly Intermittency Analysis.
- Step 4: Maximum Renewable Penetration Analysis.
- Step 5: Wind and Load Correlation Analysis.

2.1. Step 1: Transmission Data Collection and Base Case Development

The Energy Commission requested the California Investor Owned Utilities (IOU) and municipal utilities provide solved transmission power flow models for the IAP transmission study periods. California utilities provided transmission power flow data based primarily on Western Electricity Coordinating Council (WECC) models, as described in Table 2-1.

Table 2-1: Power Flow Base Cases

Case	Description	Source
08la1sa	WESTERN ELECTRICITY COORDINATING COUNCIL 2008 LA1-SA APPROVED BASE CASE FEBRUARY 9, 2005	Pacific Gas and Electric Company
a05sprpk2010	PG&E 2005 Transmission Expansion Plan Assessment 2010 HEAVY SPRING 5/9/2005	Pacific Gas and Electric Company
a05sum2010	PG&E 2005 Transmission Expansion Plan Assessment 2010SUMPK: SYSTEM CASE (1-IN-5 LOAD)	Pacific Gas and Electric Company
a05sum2015	PG&E 2005 Transmission Expansion Plan Assessment 2015SUMPK: SYSTEM CASE (1-IN-5 LOAD)	Pacific Gas and Electric Company
2010hs_rev4	2010 Base Case For 2005 SDG&E Grid planning studies Load+losses=5038MW case last modified 6-10-2005 This case contains the proposed 500kV line from IV to Central.	San Diego Gas and Electric Company
2015hs_rev4	2015 Base Case For 2005 Grid planning studies Load+losses=5513MW case last modified 6-10-2005	San Diego Gas and Electric Company
hs11-ih	PG&E 2004 Transmission Expansion Plan Assessment 2014 System Summer Peak Base Case COI=4800MW (n2s), P26=2300MW (n2s) 3/26/2004 by SATS	Sacramento Municipal Utility District
2005 Summer	OFFICIAL CASE FOR CALIFORNIA 2005 SUMMER PEAK	California Energy Commission Strategic Value Analysis (Davis Power Consultants et al. 2005)

COI = California Oregon Intertie

The 2005 summer case provides a reference point when scaled to 2006 summer peak loads and 2010 corresponds to the renewables portfolio standard (RPS) energy target of 20%. The DPC team scaled the 2015 cases to 2020 to align with the RPS energy target of 33%. Section 4.0 details the development of the base case power flow data sets.

2.2. Step 2: Development of Study Cases and Renewable Mix

The DPC team then developed the renewable study cases from the base cases. Section 5.0 details the development of the four study cases. Each study case had its own renewable penetration target and associated transmission expansion. The DPC team analyzed the study cases using transmission load flow and voltage stability tools and evaluated each renewable site for its impact on transmission grid security. The study scenarios, consisting of summer, spring, and fall cases, included:

- 2010 Tehachapi (2010T) – 20% renewable penetration with 3,000 MW of wind capacity at Tehachapi.
- 2010 XA – same as 2010 Tehachapi, but used for maximum renewable energy penetration analysis.
- 2010 XB – 33% renewable penetration.
- 2020 – 33% renewable penetration.

The renewable mix to meet the 20% and 33% RPS goals included geothermal, residential photovoltaic (PV), concentrated solar power (CSP), wind, and biomass resources. The mix was based on the renewable capacity at each site and the total projected energy generation. The wind resources are the variant sources studied in this analysis, due to lack of available variation data of other resources.

2.3. Step 3: Hourly Intermittency Analysis

The DPC team studied the hourly intermittency impacts on the transmission grid for the 2010 Tehachapi, 2010 XB, and 2020 cases. Transmission power flow studies normally analyze a single point in time such as the summer peak hour. However, the DPC team performed a time-step power flow analysis, incorporating time-varying generation from intermittent resources to determine the overloaded transmission elements and the duration of the overloads. The transmission planner can then assess if transmission upgrades can relieve a long-duration overload or if a Remedial Action Scheme (RAS), such as load dropping or branch switching, can relieve a short-duration overload.

2.4. Step 4: Maximum Renewable Penetration Analysis

The DPC team developed a sensitivity case to estimate the maximum penetration of the renewable resource mix supported by the transmission grid. The team assumed that transmission upgrades and new line construction for the 2010 and 2020 cases would consist of standard tower and pole construction and transmission wire sizes. Transmission lines and transformers are never sized to exactly meet the overload values. As such, there is excess transmission line and substation capacity that may be available for additional loading. The maximum penetration analysis identified locations of surplus transmission capacity and where additional resources could be added to take advantage of it. The 2010 Tehachapi case included a transmission expansion plan for delivering new renewable power to the load. The study found under this scenario that up to 26% of the energy could be generated by renewable resources to support the 20% RPS energy target.

2.5. Step 5: Wind and Load Correlation Analysis

Hourly changes in wind generation and load often require responses in generator unit commitment and voltage control device switching. The DPC team analyzed the correlation between changes in wind generation and load. Understanding these correlations enables transmission planners to better expand the transmission grid.

Correlation analysis can be completed for both historical and forecast data, with emphasis on the entire state, a region, a utility service area, or a transmission congestion zone. An analyst could study the correlation between load and wind to determine the seasons and time periods of greatest interest for further analysis. While transmission planning traditionally focuses on periods of peak load, periods in which load and wind are uncorrelated or negatively correlated (i.e., move in opposite directions) may be more critical for intermittency analysis. In the IAP production simulation study, GE Consulting developed hourly wind forecasts for 147 wind sites. Unfortunately, the DPC team did not have access to the forecast wind patterns for the 147 wind sites and instead analyzed 2004 historical hourly wind generation totals from five wind producing regions in California.

3.0 IAP Transmission Objectives and Evaluation Techniques

The objectives of the IAP transmission study were to:

- Identify anticipated transmission congestion locations.
- Evaluate transmission and other grid improvements required to accommodate 2010 and 2020 renewable resources.
- Provide contiguous data sets for statewide transmission planning and evaluation.
- Develop analytical tools and methodologies which would enhance the system planner's ability to incorporate least-cost, best-fit renewables into transmission grid reliability assessment.
- Foster a collaborative planning process among stakeholders.

Many recent studies have investigated the impacts of intermittent resources on operations such as spinning reserves, load following, regulation, and unit commitment. This study is unique in its focus on the transmission grid.

The California utilities, state agencies, federal agencies, and developers need methodologies and tools to evaluate the transmission impacts of intermittent resources in determining the least-cost, best-fit renewable resource locations that are beneficial to transmission security. A methodology must be easy to use and understandable. The interested parties and collaborative study groups can use one set of transmission power flows to obtain a better understanding of transmission congestion and renewable mix impacts on a statewide, utility, and regional basis.

To facilitate these objectives, the DPC team developed three evaluation techniques:

(1) renewable site specific benefit ratio tests.

(2) state-wide benefit ratio tests.

(3) hourly time-step intermittency analysis.

Each renewable site has transmission upgrade requirements to deliver energy to the load as well as its own transmission benefit ratio value. As more renewables are added to the system, the cumulative additions create new transmission overloads that necessitate new upgrades. After determining the overload conditions and upgrades, the DPC team used the hourly time-step technique to evaluate the duration and severity of the overloads and the best type of mitigation measure.

3.1. Contingency Simulation and Benefit Ratio Test

The DPC team developed several analysis tools to evaluate the transmission system performance under various scenarios, renewable mixes, and intermittent resource production levels. An analytical approach to transmission system expansion requires the simulation of the transmission system under a set of contingencies. Typically, transmission systems are built with redundancy to withstand severe contingencies without losing load or experiencing security violations such as transmission overloads. The DPC team tabulated the effects of contingencies to determine useful metrics to guide expansion plans.

For each scenario, the DPC team simulated a set of approximately 7,000 contingencies with automated tools, which produced a list of overloaded transmission elements. The study considered all contingent outages of single transmission lines, single transformers, and single generators (n-1), and measured contingency overloads only on non-radial transmission elements in California. The simulations incorporated linear approximations of post-contingent conditions to reduce simulation runtime. The linear approximations used flow sensitivities to estimate changes in real power flows and did not evaluate reactive power flows.

Following contingency analysis, the DPC team calculated the *Aggregate Megawatt Contingency Overload (AMWCO)* metric for each element in the system. AMWCO is zero for all elements that do not exceed their maximum rated flow under all simulated contingencies. For elements that overload during at least one contingency, the AMWCO for each element and contingency equals the amount of flow on the element during the contingency minus the element's maximum rated flow. Summing these values across all simulated contingencies yields an AMWCO for each transmission element. Thus the value of AMWCO is small for elements with one or a few non-severe overloads. It has a medium value for elements with a few severe overloads or many non-severe overloads and a high value for elements with numerous severe overloads. Summing the AMWCO across all transmission elements yields the System AMWCO, a measure of the security level of the entire system.

The DPC team evaluated the impact of proposed renewable energy generation projects on the transmission system for each simulated scenario. The *Renewable Transmission Benefit Ratio (RTBR)* is the change in System AMWCO per MW of renewable generation:

$$RTBR = \frac{AMWCO_{renewable} - AMWCO_{base}}{MW_{renewable}}$$

Thus RTBR measures the impact of the renewable project on system security. Negative RTBR indicates an improvement in system security.

3.2. Hourly Time Step Intermittency Analysis

To examine the impact of intermittent resource production on the transmission system security, the DPC team conducted an hourly simulation to determine the AMWCO of all the transmission elements for a set of hours and compiled the AMWCO for each hour and for each transmission element. This AMWCO matrix yields several useful metrics. The sum of an element's AMWCO across all hours represents the total megawatt hours of energy overload on that element, considering the entire contingency set. The resulting *Aggregate Megawatt Hour Contingency Overload (AMWhCO)* ranks transmission elements' susceptibility to overload during the hourly simulation.

For select transmission elements, the DPC team developed duration curves to indicate the number of hours that AMWCO exceeded a certain level. Applying transmission expansion policies, the AMWhCO and the AMWCO duration curve suggest a set of transmission lines that should be protected with remedial action schemes or upgrades.

For each hour, the System AMWCO is the sum of each transmission element's AMWCO and the System AMWhCO is the sum of each transmission element's AMWhCO. The study applied the System AMWCO duration curve and the System AMWhCO to evaluate security of the overall California transmission system under variable wind conditions. The variability of the hourly AMWCO and extreme minimum and maximum hourly AMWCO measures the variability imposed by changing and intermittent regional wind conditions. The study evaluated these metrics for individual transmission elements and the entire system and identified specific regional wind production patterns that correlate with the most heavily overloaded conditions.

3.3. Other Analysis Tools

In evaluating the maximum penetration of renewable resources in the total California generation portfolio, the DPC team determined the *Available Transfer Capability* (*ATC*) for the renewable mix. ATC is a measure of the thermal capacity[5] of the transmission network to accommodate a proposed transfer of energy. The ATC helps identify how much the renewable generators can collectively increase their production without forcing transmission overloads, and which parts of the transmission network limit further increases in renewable generation.

When system load and power transfers approached the limits of the transmission network, the DPC team applied *Power-Voltage (P-V)* and *Reactive Power-Voltage (QV)* analyses to model reactive power sources to increase stability margins. P-V analysis evaluates the capacity of the transmission network to accommodate a proposed transfer of power, while supporting system voltages and avoiding voltage collapse. QV analysis evaluates the reactive power margin at specific points in the system. It determines how much reactive support is required at a bus to maintain its voltage at a desired level and how much reactive load a bus can support without voltage collapse.

5 In this study, thermal capacity is defined as the line and transformer ratings as provided in the WECC data sets. These limits may represent line ratings, nomogram limits, intertie limits, or other limits on the availability of the line to transfer energy across the grid.

4.0 IAP Transmission Power Flow Case Development

The study scope included three years (2006, 2010 and 2020). This section provides a brief discussion of the power flow models used for each.

4.1. 2006 Base Case Power Flow Data Set Development

The reference year for the IAP transmission study is 2006. The 2005 Integrated Energy Policy Report (IEPR) and previous DPC work for the Energy Commission on renewable penetration yielded a 2005 summer peak power flow data set. The DPC team maintained the 2005 resource mix and escalated the California loads by 3% for the 2006 base case. The 2005 analysis included only a summer peak scenario.

The 2006 reference summer power flow case includes all of the existing renewable technologies. The renewable mix is:

Geothermal	2,338 MW
Hydro	11,786 MW[6]
CSP solar	332 MW
Wind	2,153 MW
Wood, Biomass	711 MW
Total	17,321 MW

This reference data set is used to evaluate the impacts that intermittent renewable technologies have on the existing system and as a potential point of reference.

4.2. 2010 Base Case Power Flow Data Set Development

The DPC team contacted the individual IOUs to obtain copies of solved transmission power flow data sets for spring, summer, and fall 2010. The Pacific Gas and Electric Company (PG&E) data sets included the entire WECC region and represented the summer and spring of 2010 and the fall of 2008. Although these data sets were all developed in 2005, the system topologies were not consistent in each case.

The San Diego Gas & Electric Company (SDG&E) provided redacted summer 2010 and 2015 data sets, covering only the SDG&E service area. In addition, SDG&E provided cases with and without the proposed 500 kV transmission line from SDG&E service area to Imperial Valley. The Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility District (SMUD) provided information later in the data set development. The DPC team incorporated SMUD power flow data into the 2020 power flow data sets.

6 Gross hydro total; not adjusted for actual hydro generation classified as renewable.

The Imperial Valley Geothermal Study Group provided maps of proposed transmission expansion to support up to 2,000 MW of geothermal resources. Since the transmission routes described in the 2005 IEPR analysis for 2010 were consistent with those described by the study group, the IAP study used the 2005 IEPR routes and typical transmission characteristics. The IAP study did not propose new phase shifting transformers since they may require future relocation or replacement as additional transmission lines are added to the system.

A Tehachapi Wind Study Group studied transmission alternatives for exporting several thousand megawatts of wind power from Tehachapi. Since the study group had not recommended a transmission expansion case, Energy Commission staff and the DPC team worked with the study group to recommend a transmission plan for the IAP study. The California ISO provided characteristics for the proposed transmission lines. The advantage in using the study group data is the modeling of the transmission and transformer characteristics. However, phase shifters are not modeled. The DPC team verified utility loads and resource generation by fuel type with production costing results from the Energy Commission Electricity Analysis Office (EAO).

A challenge in developing power flow models was obtaining correct and consistent topology (network connectivity) between years and seasons, as problems emerged with bus numbering, bus naming, and transmission configurations. The DPC team observed inconsistencies between models for the three seasons and determined that the bus and transmission topology in the summer models could be used for all seasons within the same year. The team maintained the spring and fall loads and interchanges from the original cases but imported the topology from the summer case. Consistent topology across models greatly facilitates all subsequent analysis, including the expansion of renewable resources, contingency simulation, and system security evaluation. It also makes comparison of intermittency analysis results across seasons and years more meaningful.

4.3. 2020 Base Case Power Flow Data Set Development

The 2015 summer and spring cases were the most forward-looking power flow models provided by the utilities. The 2015 period serves as an interim reference for projected load growth, resource penetration, resource adequacy requirements, and interchanges between the 2010 and 2020. Though it is not part of the IAP study, the EAO studied 2015 in its production costing model. The DPC team scaled the 2015 models to 2020 to study the 33% penetration.

The 2015 spring case loads were inconsistent with the 2015 summer case loads. There was no 2015 fall case. The DPC team estimated the spring peak and fall off-peak loads from the 2015 EAO forecast, using the ratios between the seasonal loads from the 2010 power flow models.

The 2010 summer and the 2015 summer models revealed numerous bus numbering, bus naming, and topology inconsistencies. The DPC team imported the topology from the 2010 summer model into the 2015 models, except where the 2015 model topology represented transmission expansion from 2010. The team then escalated the 2015 loads to 2020 at a compound annual growth rate of 1.5%.

4.4. Base Case Power Flow Results

The DPC team analyzed single-element contingencies (N-1) for the summer, spring, and fall 2010 and 2020 IAP base cases and calculated the System AMWCO security metric described in Section 3.1. These results can be compared to System AMWCO results from the 2005 Strategic Value Analysis (SVA) Study (Davis Power Consultants et al. 2005), referenced in the 2005 IEPR. These summer peak base cases modeled systems in 2003, 2005, 2007, 2010, and 2017. Figure 4-1 shows the comparison results.

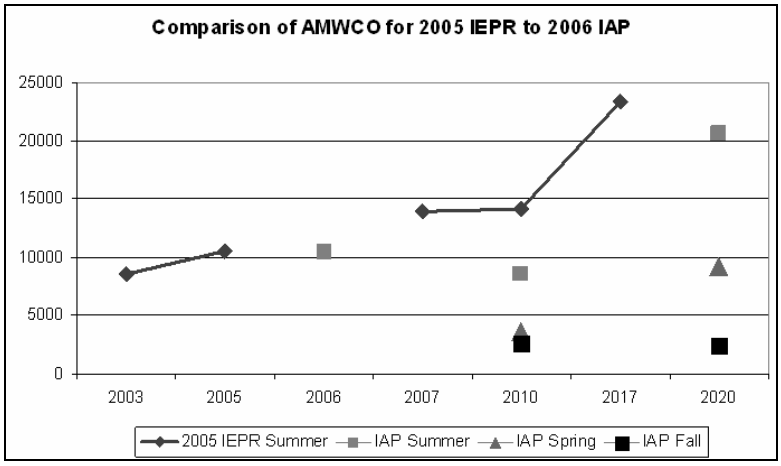

Figure 4-1: Comparison of System AMWCO for 2005 IEPR to 2006 IAP

The gaps in the graph represent years that were not studied. The System AMWCO values increase over time with increasing load as transmission improvements are limited to existing lines and state agency-approved transmission and power plant expansions. The largest change in System AMWCO in the 2005 IEPR occurs between 2010 and 2017, since the 2017 model includes no new transmission lines or state-approved power plants. The average annual increase in the System AMWCO between 2003 and 2010 is 695 MW, but it almost doubles to 1,319 MW between 2010 and 2017.

Since the DPC team derived the IAP 2006 summer base case from the 2005 IEPR base case, the System AMWCO for the two are consistent, with a slight improvement in 2006 due to additional known transmission projects and upgrades. The 2010 IAP summer base case results are almost identical to those of the 2003 IEPR case. The 2010 IAP summer case reflects more transmission expansion and does not have the modeling inconsistencies of the IEPR cases. The 2020 IAP summer base case results are similar to those of the 2017 IEPR case. Both cases reflect similar modeling limitations, with a limited scope of anticipated and approved expansions projected so far into the future.

Figure 4-1 also shows results from the spring and fall IAP base cases, which reflect an improvement from the summer due to lower loads and different levels of imports and intra-California flows. The summer System AMWCO best reflects the limits of system security.

5.0 IAP Study Case Development and Benefit Ratio Results

Five study cases are developed for the IAP study:

- 2006 – Existing renewable mix.
- 2010 Tehachapi – 20% renewable mix with 3,000 MW of wind at Tehachapi.
- 2010 XA – Interim 2010 Tehachapi used for penetration analysis.
- 2010 XB – 2010 Tehachapi expanded to 33% renewable mix.
- 2020 – 33% renewable mix.

The 2006 IAP case analyzes transmission security (reliability) benefits of the existing five wind areas. This case serves as a reference point for the other cases. When the IAP study is first started, the 2010 renewable mix from the 2005 IEPR is used as the initial 2010 20% study case. However, the Tehachapi wind developers are submitting numerous projects into the California ISO queue. The Tehachapi wind study group finished a study on high penetrations of Tehachapi wind. The major utilities requested that the IAP 2010 mix be changed to reflect the higher penetrations at Tehachapi. The 2010 Tehachapi case reflects this higher penetration of wind, which alters the original renewable mix.

The 2010 XA and XB are special study cases. The 2010 XA models the same renewable mix and transmission expansion as the 2010 Tehachapi case. The case is a special study for determining the additional renewables that can be added given the transmission expansion in the 2010 Tehachapi case. The 2010 XB case adds sufficient transmission to support a 33% renewable penetration in 2010 and is designed to study the operating impacts of higher penetrations of renewables[7]. The 2020 case is based on the projected increase to a 33% renewable energy penetration.

The 2010 and 2020 study cases use a wind output of 60% of the installed wind capacity for the summer, spring, and fall transmission power flow cases to determine the transmission expansion requirements. The same percentage is assigned to all of the wind sites equally. The transmission expansion may be over stated in some seasons under this modeling assumption.

In 2004, there are 153 hours where the total wind generation from Solano, Altamont, Pacheco, San Gorgonio, and Tehachapi exceed 60% of the connected wind capacity for these areas. The highest percentage is 70%. The average wind capacity percentage over the 153 hours for the three northern California wind areas is 56%, while the average for southern California wind areas is 69%. The months in which these occur are March, April, May, June, and September. The three seasons in the IAP analysis fall within these months, depending on the assignments of months to seasons. The 60% capacity factor for wind is realistic, based on this preliminary analysis.

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[7] Although it is not proposed that California mandate a 33% renewable energy penetration for 2010, the case is developed for sensitivity analysis and trending impacts.

Sensitivity analyses are completed with wind generating at 100% of capacity. The transmission system must handle the maximum capacity from any one of the wind areas.

Each of these cases is discussed in the following sections.

5.1. 2006 Study Case and Transmission Benefit Ratio Results

Table 5-1 lists the capacity from the 2006 existing wind sites. The megawatts are obtained from the 2006 power flow data sets and verified with the CAISO. Since the Pacheco Pass, San Diego, and other wind sites are small in comparison with the four wind areas, these areas are ignored for the transmission benefits ratio tests.

Table 5-1: Capacity from the Existing Wind Sites

Wind Location	Solano	Altamont Pass	Pacheco Pass	Tehachapi	San Gorgonio	San Diego	Other	Total
MW	220	662	13	760	462	12	24	2,153

The AMWCO and the RTBR, i.e. the impact ratio indices, for Altamont and Solano wind areas are shown (relative to the base case AMWCO in PG&E without Altamont or Solano injection) in Table 5-2. The RTBR is the change in AMWCO between the base case and the renewable case divided by the total MW of renewables installed. A RTBR of less than zero indicates that the system security is improved by the addition of the renewables. The cases with Altamont Pass wind generators at 60% and 100% capacity factors for the summer 2006 summer peak have impact ratios of -17 and -10, respectively. In the case of Altamont at 60% generation, every MW of generation provides a 17 MW benefit to transmission reliability. Note that the transmission reliability index decreases when Altamont wind generation is at 100%. This indicates that the transmission reliability of wind generation at this site decreases as wind generation increases due to an increase in overloads on some transmission lines and transformers. Additional transmission improvements are needed if a higher impact ratio is desired. The Solano wind site has a much higher impact ratio than Altamont. This indicates that either the Solano wind area is closer to major transmission corridors or to major load centers.

Table 5-2: Northern California Summer Peak 2006 Wind Analysis

	Base	Altamont In Solano Out	Altamont In Solano Out	Solano In Altamont Out	Solano In Altamont Out
Wind Penetration	0% case	60% case	100% case	60% case	100% case
AMWCO	16055.7	9187.8	9368.0	8987.1	8761.3
Wind MW	0	397.3	662.2	132	220
RTBR	--	-17	-10	-53	-33

As a comparison, Table 5-3 shows the results for the Tehachapi and San Gorgonio wind areas, relative to the base case AMWCO in Southern California without Tehachapi or San Gorgonio injection. The impact ratio for San Gorgonio increases as the existing wind generation is

increased to 100%. This indicates that additional wind generation at San Gorgonio may continue to provide higher transmission security benefits. The Tehachapi wind area has the lowest impact ratio. The value of 0.3 for wind at 100% indicates that wind generation provides little additional value to the system as far as transmission reliability. For every 1 MW of wind generation at Tehachapi there is a benefit of 0.3 MW to transmission reliability. The RTBR value is neutral in providing transmission benefit, however higher penetrations of wind may create transmission security problems without additional upgrades.

Table 5-3: Southern California Summer Peak 2006 Wind Analysis

	Base	San Gorgonio In Tehachapi Out	San Gorgonio In Tehachapi Out	Tehachapi In San Gorgonio Out	Tehachapi In San Gorgonio Out
Wind Penetration	0%	60%	100%	60%	100%
AMWCO	5235.0	4412.9	3769.6	5167.0	5097.4
Wind MW	0	248.7	414.5	324.5	539.1
Impact Ratio	--	-3.3	-3.5	-0.2	-0.3

5.2. 2010 Tehachapi Study Case and Transmission Benefit Ratio Results

The 2010 Tehachapi case has the 20% energy penetration target, but with 3,000 MW of wind at Tehachapi. One new wind project (120 MW) by LADWP and two large CSP projects by SDG&E and Southern California Edison (SCE) (300 MW and 500 MW) are projected to be completed before 2010, and are included as well. These changes alter the 20% renewable mix as shown in Table 5-4.

Table 5-4: Comparison of 2010 20% Renewable Cases

Location	Technology	Original 2010 @ 20%	2010 IAP T @ 20%
Salton Sea	Geothermal	800	600
Mount Signal	Geothermal	19	19
Heber	Geothermal	42	20
Brawley North	Geothermal	135	135
Sulfur Bank	Geothermal	43	50
Medicine Lake	Geothermal	175	175
Niland	Geothermal	-----	65
Urban, Agr, Veg	Biomass	228	221
Tehachapi	High Wind	900	3,000
Riverside	High Wind	1,416	1,412
San Bernadino	High Wind	168	168
SDGE	High Wind	150	90
Solano	High Wind	275	165
Altamont	High Wind	132	80

Location	Technology	Original 2010 @ 20%	2010 IAP T @ 20%
LADWP Wind	High Wind	120	120
Imperial	CSP		146
SCE CSP	CSP	300	300
SDG&E CSP	CSP	500	500
Statewide	Res Solar	500	533
Total (MW)		5,903	7,799
Total (MWh) Energy Target (MWh)		24,969,000 28,969,000	29,621,677 28,969,000

MWh = megawatt-hour

Some corrections to a few renewable resources, such as the Urban Fuel, Sulfur Bank, and Imperial CSP, are implemented. The wind output at Tehachapi is increased to 3,000 MW, and other resources are reduced to meet the 20% energy target. Some of the adjustments are made to Salton Sea, Solano, and Altamont. The resulting energy penetration is 2% higher than the penetration target.

The original case does not meet the 2010 energy target. In the original study, the renewable penetration mix is based on a least-cost, best-fit analysis. The target is missed since some of the renewables are not cost beneficial and some of the transmission expansion is projected to be completed after 2010. The least-cost, best-fit requirement is not strictly adhered to for the IAP study since the objective is to maximize the intermittent resource penetration for intermittency impacts. For a more thorough understanding of the least-cost, best-fit criteria (otherwise called the Strategic Value Analysis) please review the Energy Commission reports listed in the reference.

The Energy Commission EAO completed production cost simulations for a 20% renewable mix. The renewable mix is similar but not identical to the IAP mix. The EAO selected conventional gas-fired resources that are required to serve load and meet planning reserve margins since the intermittent resources have a low resource adequacy capacity. The EAO determined gas–fired generator additions are included in the IAP study. Table 5-5 lists the gas units and their projected location.

Table 5-5: New Gas-Fired Generators

AREA	STATUS	BUS	NAME	TYPE	MW	DATE
SDG&E	Retired	22780	SouthBy1			2008
SDG&E	Retired	22784	SouthBy2			2008
SDG&E	Retired	22788	SouthBy3			2008
SDG&E	Retired	22792	SouthBy4			2008
SCE	New	24151	VALLEY	CCCT- Frame H	387	2008
SCE	New	24151	VALLEY	CCCT- Frame H	387	2008
SCE	New	24151	VALLEY	DT	26	2008
SMUD	New	37524	Sutter	SCCT	150	2008
IID	New	21026	El CENTRO	SCCT	50	2009
LADWP	New	26025	HAYNES	SCCT	150	2009

AREA	STATUS	BUS	NAME	TYPE	MW	DATE
PG&E	New	30873	Helm	CCCT- Frame G	250	2009
PG&E	New	30873	Helm	DT	30	2009
PG&E	New	30875	Mccall	CCCT- Frame G	250	2009
SMUD	New	37547	Folsom	SCCT	150	2010
SDG&E	New	22768	South Bay	CCCT- Frame G	140	2011
SDG&E	New	22772	South Bay	CCCT- Frame G	360	2011
SCE	New	24077	LBEACH	SCCT	150	2011
PG&E	New	30624	Tesla E	SCCT	150	2011
PG&E	New	30873	Helm	CCCT- Frame G	250	2011
PG&E	New	30875	Mccall	DT	15	2011
PG&E	New	31000	Humboldt	SCCT	150	2011
PG&E	New	33204	Potrero	SCCT	150	2011
SMUD	New	37549	Folsom	SCCT	150	2011
SCE	New	24077	LBEACH	SCCT	150	2012
SCE	New	24077	LBEACH	SCCT	150	2012
PG&E	New	30560	Eastshore	CCCT- Frame G	265	2012
SCE	New	24401	ANTELOPE	CCCT- Frame G	259	2013
SCE	New	24401	ANTELOPE	CCCT- Frame G	259	2013
PG&E	New	32786	OAK C115	SCCT	150	2013
SMUD	New	37549	Folsom	SCCT	150	2013
PG&E	New	37585	Tracy	DT	26	2013
PG&E	New	37585	Tracy	CCCT- Frame G	265	2013
LADWP	New	26025	HAYNES	SCCT	150	2015
PG&E	New	33540	Tesla	SCCT	150	2015
SMUD	New	37016	Ranchoseco	CCCT- Frame G	250	2015
SMUD	New	37016	Ranchoseco	CCCT- Frame G	250	2015
SMUD	New	37016	Ranchoseco	DT	30	2015
TOTAL					5,849	

IID = Imperial Irrigation District

First contingency (N-1) power flow contingency analyses are completed for the 2010 Tehachapi case. Figure 5-1 graphically displays the AMWCO values as the renewables listed in Table 5-4 are incrementally added and new power flow simulations completed. The summer power flow cases have the largest change in AMWCO values from the base case to the last renewable added. This is expected since the initial summer AMWCO value is significantly higher than the spring and fall values. The missing data from the fall case are the solar facilities that are not operating during off-peak conditions at night. Table 5-6 lists the renewable resources that are associated with each renewable segment.

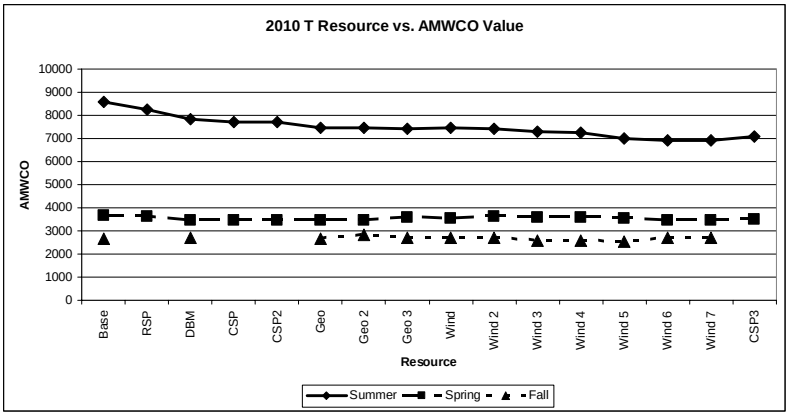

Figure 5-1: AMWCO Results for the 2010 Tehachapi Case

Table 5-6 shows the cumulative AMWCO as the different renewables are added to the system. The initial summer AMWCO of 8,579 represents the transmission security value of the base case while the last value of 6,909 represents the cumulative AMWCO value after adding all of the renewables. The slope of the line changes as the order of installation of the renewables changes, but the initial and final values are the same regardless of the order of the renewable additions. The summer AMWCO changes are more dramatic than the spring and fall. This is expected since the loads, generation, and interchange values change between seasons.

Table 5-6: List of Renewable Resources in the AMWCO Simulations

Resource Region	Reference	AMWCO		
		Summer	Spring	Fall
	Base	8,579	3,672	2,686
State-Wide Residential PV	RSP	8,237	3,623	-
State-Wide Biomass	DBM	7,828	3,469	2,720
SCE	CSP	7,720	3,464	-
SDG&E	CSP2	7,699	3,444	-
Sulfur Bank	Geo	7,451	3,441	2,673
Medicine Lake	Geo 2	7,450	3,451	2,824
Imperial Valley Geothermal	Geo 3	7,430	3,577	2,720
LADWP	Wind	7,468	3,561	2,727
Altamont	Wind 2	7,404	3,605	2,720
SDG&E	Wind 3	7,300	3,564	2,563
Solano	Wind 4	7,257	3,574	2,567
Riverside	Wind 5	6,998	3,534	2,556
Tehachapi	Wind 6	6,910	3,469	2,721
San Bernardino	Wind 7	6914	3461	2711
Other CSP	CSP 3	7074	3507	------

Another way of analyzing the value of the renewable sites is the RTBR. Table 5-7 lists the RTBR results for the 2010 Tehachapi case. The Sulfur Bank geothermal, state-wide biomass, and SDG&E wind site provide the highest negative summer RTBR or the highest reduction in AMWCO. Other renewable locations provide little benefit to the summer AMWCO but are all mostly negative or near zero. The spring RTBRs are all close to zero, meaning that the renewables do not add significant value to the system under this condition. In the fall case, most RTBR values are close, except for the SDG&E wind and Sulfur Bank geothermal. These sites do provide more significant transmission benefit.

Table 5-7: Cumulative 2010 Tehachapi RTBR values

Resource Region	Reference	RTBR		
		Summer	Spring	Fall
	Base	------	------	------
State-Wide Residential PV	RSP	-0.64	-0.09	------
State-Wide Biomass	DBM	-1.85	-0.70	0.15
SCE	CSP	-0.36	-0.02	------
SDG&E	CSP2	-0.04	-0.04	------
Sulfur Bank	Geo	-4.97	-0.06	-0.94
Medicine Lake	Geo 2	-0.01	0.05	0.87
Imperial Valley Geothermal	Geo 3	-0.02	0.15	-0.12
LADWP	Wind	0.32	-0.14	0.06
Altamont	Wind 2	-0.79	0.56	-0.09
SDG&E	Wind 3	-1.16	-0.46	-1.74
Solano	Wind 4	-0.26	0.06	0.02
Riverside	Wind 5	-0.18	-0.03	-0.01
Tehachapi	Wind 6	-0.03	-0.02	0.06
San Bernardino	Wind 7	0.03	-0.05	-0.06
Other CSP	CSP 3	1.09	0.32	------

The addition of new renewable resources requires new transmission lines, transmission line upgrades, transformer upgrades and new substation transformers. The 20% renewable penetration can not be accomplished with the locations selected for this IAP study if the new transmission elements are not developed. Table 5-8 summarizes the number of new elements by voltage category for transmission lines and substation transformers. A transmission element is a transmission line that connects two substations together. The 500 kV transmission lines are associated with the Tehachapi 3,000 MW wind development. The remaining line requirements are distributed throughout the PG&E, SCE, and SDG&E service areas. Most of the transmission line and transformers upgrades are infrastructure improvements to transmit power from source to sink. Many of these lower voltage lines are heavily loaded in the base case and become overloaded over time as load increases or economic dispatch changes. The utilities are already

beginning to upgrade some transmission lines and transformers that are selected in the IAP analysis.

Table 5-8: 2010 Tehachapi Case Transmission System Upgrades Requirements

Transmission Line	From Bus Nominal kV	# of Elements	Substation Transformer	From Bus Nominal kV	# of Elements
Yes	500	4	Yes	500	2
Yes	230	7	Yes	230	5
Yes	161-115	49	Yes	161-115	10
Yes	110 & Below	14	Yes	110 & Below	14
Total		74	Total		31

The 2010 Tehachapi case, with all of its projected transmission upgrades, improves transmission reliability under first contingency (N-1) conditions while meeting the renewable penetration targets. The study does not consider the feasibility of constructing all of these elements. For an order of magnitude on the potential costs of the 500 kV and 230 kV transmission lines and towers only, the cost is projected to be $1.2 billion. The projected cost for the 31 transformers is projected to be $161 million. All costs are projected to be in 2006 dollars. This analysis so far has not evaluated the hourly effects of the intermittency of renewables, only the effects at a single point in time. These costs do not include right-of-way, permitting, environmental studies, and other costs. These should be considered only overnight[8] line costs.

5.3. 2020 Study Case and Transmission Benefit Ratio Results

The initial list of renewables for the 2020 33% renewable penetration comes from the 2010 Tehachapi case. The renewable mix and all of the associated transmission and substation transformer upgrades from the 2010 Tehachapi case are integrated into the 2020 case. The renewable mix is then expanded from 20% to 33%.

The objective in the 2020 33% case is to study the effects of intermittent resources on the California grid. The least-cost, best-fit is not strictly adhered to since the renewable targets are to be met with in-state resources. Some of the renewables added did not meet the criteria. There are also no adjustments made to the mix to account for transmission construction time lines, as is considered in the 2005 IEPR.

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8 "Overnight capital costs" is a term of art commonly used to indicate that the capital costs, as expressed, do not include costs of capital, costs of work in progress, allowances for funds used during construction, even when the construction projects span more than one calendar year. Typically utilities do account for these additional capital requirements when projects span multiple years. However, regulatory treatment of these capital requirements varies widely among jurisdictions and even within jurisdictions between transmission and generation projects. Therefore, in order to compare the relative ranking of projects by initial capital costs, it is assumed that these projects are completed "overnight" thus negating the above stated "adders" to the project's costs.

Table 5-9 compares the 2010 Tehachapi case at 20% renewable mix and 2020 at 33% renewable mix. Both the capacity and energy from each renewable resource is listed. This comparison shows the magnitude of the renewable additions needed to meet the 33% target.

Table 5-9: Comparison of 2010 Tehachapi and 2020 Study Cases (New Renewables Only)

Location	Technology	2010T 20% Mix (MW)	2010T 20% Mix (GWh)	2020 33% Mix (MW)	2020 33% Mix (GWh)
Fire Threat	Biomass			133	990,318
Urban, Agr, Veg	Biomass	221	1,742,364	857	6,756,588
San Diego	CSP			100	236,520
Imperial	CSP			450	1,064,340
Riverside	CSP	73	172,659	200	473,040
San Bern	CSP	73	172,660	300	709,560
SCE CSP	CSP	300	709,560	850	2,010,420
SDG&E CSP	CSP	500	1,182,600	500	1,182,600
Lassen CSP	CSP			300	709,560
Salton Sea	Geothermal	600	4,730,400	1,400	11,037,600
Mount Signal	Geothermal	19	149,796	19	149,796
Heber	Geothermal	20	157,680	42	331,128
Brawley North	Geothermal	135	1,064,340	135	1,064,340
Sulfur Bank	Geothermal	50	394,200	43	339,012
Medicine Lake	Geothermal	175	1,379,700	175	1,379,700
Niland	Geothermal	65	512,460	42	331,128
Geysers	Geothermal			400	3,153,600
Brawley East	Geothermal			129	1,017,036
Tehachapi	High Wind	3,000	9,723,600	4,500	14,585,400
Riverside	High Wind	1,412	4,576,574	1,412	4,576,574
Medicine Lake Telephone Flat	High Wind			130	421,356
San Bern	High Wind	168	544,522	640	2,074,368
SDGE	High Wind	90	291,708	500	1,620,600
Imperial	High Wind			600	1,944,720
LADWP Wind	High Wind	120	388,944	200	648,240
Pacheco	High Wind			40	129,648
Solano	High Wind	165	534,798	1,085	3,516,702
Lassen Wind	High Wind			650	2,106,780
Altamont	High Wind	80	259,296	200	648,240
Inyo	Low Wind			100	219,000
Contra Costa	Low Wind			28	61,320
Ventura	Low Wind			50	109,500
Yolo	Low Wind			3	6,570
All	Res Solar	533	933,816	2,860	5,010,720
Total		7,799	29,621,677	19,073	70,616,024
Energy Target			28,969,000		70,678,509

Table 5-10 shows the total capacity and generation by renewable resource type. Wind generation makes up 55% of the renewable energy target in 2010, but drops to 46% by 2020. CSP and residential PV comprise 10% of the energy target in 2010 and increases to 16% in 2020. This is primarily due to the large increase in residential PV penetration from the California Solar Initiative that calls for residential PV systems to be installed on one million homes. The intermittent resources of wind and solar make up 66% of the energy target in 2010 and 62% of the energy target in 2020. The large penetration of intermittent resources is adequate for analyzing potential effects on transmission. Existing renewables are not included in either Table 5-9 or Table 5-10.

Table 5-10: Comparison of Renewable Types for 2010 Tehachapi and 2020

Renewable	2010T (MW)	2010T (GWh)	2010T Energy	2020 (MW)	2020 (GWh)	2020 Energy
Wind	5,035	16,319,442	55%	10,138	32,669,018	46%
CSP	946	2,237,479	8%	2,700	6,386,040	9%
Residential PV	533	933,816	3%	2,860	5,010,720	7%
Biomass	221	1,742,364	6%	990	7,746,906	11%
Geothermal	1,064	8,388,576	28%	2,385	18,803,340	27%
Total	7,799	29,621,677	100%	19,073	70,616,024	100%

The AMWCO and RTBR are calculated for each renewable site to determine the transmission security value of the renewable resources. The individual AMWCO values are not calculated, but rather a cumulative value. A new cumulative AMWCO value is calculated as each renewable location is added to the system. The cumulative approach provides insight as to impacts to transmission security as additional renewables and associated transmission are added to the system, although this does not provide the maximum benefit to the system for each individual resource.

Figure 5-2 graphically displays the AMWCO effects as the renewables listed in Table 5-9 are incrementally added and a new power flow simulation is completed. The summer power flow case has the largest change in AMWCO values from the base case to the last renewable added. This is expected since the initial summer AMWCO value is significantly higher than the spring and fall values. The missing data from the fall run are the solar facilities that are not operating during off-peak hours at night.

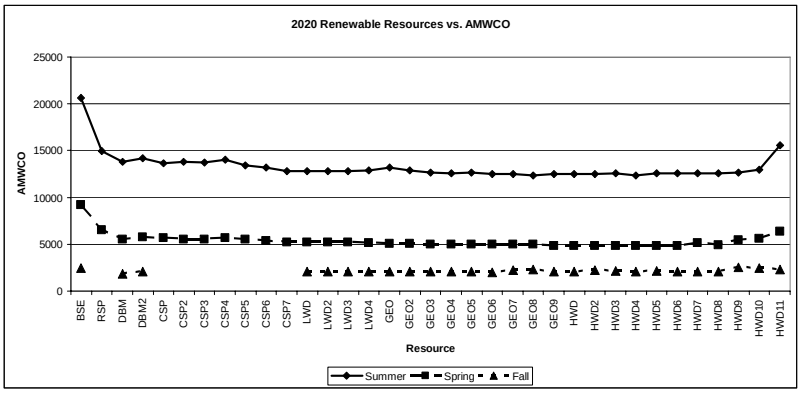


Figure 5-2: AMWCO Results for the 2020 Tehachapi Case

Table 5-11 shows the cumulative AMWCO as the different renewables are added to the system. The initial summer AMWCO of 20,655 represents the transmission security value of the base case while the last value of 15,540 represents the cumulative AMWCO value after adding all of the renewables. The slope of the line changes as the order of installation of the renewables changes, but the initial and final values remain the same regardless of the order of addition. The magnitude of the final AMWCO value indicates that there are still overloaded lines in the case. The summer AMWCO changes are more dramatic than the spring and fall. This is expected since the load, generation, and interchange values differ by season and tend to be highest during summer peak conditions. Table 5-11 lists the renewable resources that are associated with each renewable segment in Figure 5-2. The existing 2006 renewables are not included in this list.

Table 5-11: List of Renewable Resources in the AMWCO Simulations

Resource	Segment	Summer	Spring	Fall
BSE	Base	20,655	9,199	2,418
RSP	Residential	14,971	6,490	
DBM	Urban	13,819	5,527	1,820
DBM2	Fire Threat	14,169	5,778	2,046
CSP	San Diego	13,648	5,667	
CSP2	Riverside	13,787	5,508	
CSP3	San Bernardino	13,707	5,522	
CSP4	Lassen	14,013	5,638	
CSP5	Imperial	13,447	5,515	
CSP6	SDG&E	13,172	5,372	
CSP7	SCE	12,827	5,251	
LWD	Yolo	12,825	5,251	2,047
LWD2	Contra Costa	12,825	5,252	2,045
LWD3	Venture	12,813	5,247	2,048

Resource	Segment	Summer	Spring	Fall
LWD4	Inyo	12,854	5,147	2,066
GEO	Mount Signal	13,226	5,081	2,065
GEO2	Niland	12,873	5,049	2,053
GEO3	Heber	12,690	4,951	2,047
GEO4	Sulfur Bank	12,552	4,972	2,062
GEO5	Brawley North	12,637	4,972	2,040
GEO6	Brawley East	12,522	4,983	2,020
GEO7	Medicine Lake	12,509	4,967	2,204
GEO8	Geysers	12,336	5,009	2,289
GEO9	Salton Sea	12,529	4,845	2,099
HWD	Pacheco	12,532	4,843	2,097
HWD2	Medicine Lake	12,532	4,845	2,205
HWD3	LADWP	12,572	4,862	2,170
HWD4	Altamont	12,369	4,867	2,087
HWD5	SDG&E	12,547	4,856	2,132
HWD6	Imperial	12,606	4,833	2,095
HWD7	San Bernardino	12,589	5,116	2,069
HWD8	Lassen	12,541	4,930	2,037
HWD9	Solano	12,646	5,481	2,513
HWD10	Riverside	12,963	5,584	2,474
HWD11	Tehachapi	15,540	6,381	2,322

The RTBR value is another way of analyzing the value of the renewable sites. Table 5-12 shows the RTBR results. The Sulfur Bank geothermal, residential PV, state-wide biomass, SDG&E CSP, Imperial CSP, Niland geothermal, and Heber geothermal provide the highest negative summer RTBR, or the highest reduction in AMWCO. Other renewables provide little benefit to the summer AMWCO, but are mostly negative or near zero. The highest positive RTBRs are the Mount Signal geothermal and the state-wide fire threat renewables. The spring RTBRs are all close to zero except for Mount Signal and fire threat renewables. The fall values are all relatively close to zero, meaning that the renewables did significantly affect the transmission in the system.

Table 5-12: Cumulative 2020 RTBR values

Resource	Segment	Summer	Spring	Fall
BSE	Base			
RSP	Residential	-1.96	-0.94	
DBM	Urban	-1.34	-1.12	-0.70
DBM2	Fire Threat	2.63	1.88	1.70
CSP	San Diego	-5.21	-1.11	
CSP2	Riverside	0.70	-0.80	
CSP3	San Bernardino	-0.27	0.05	
CSP4	Lassen	1.02	0.39	
CSP5	Imperial	-1.41	-0.31	
CSP6	SDG&E	-0.55	-0.29	
CSP7	SCE	-0.41	-0.14	
LWD	Yolo	-0.80	-0.13	0.10
LWD2	Contra Costa	0.00	0.02	-0.06
LWD3	Venture	-0.24	-0.09	0.06
LWD4	Inyo	0.41	-1.01	0.18
GEO	Mount Signal	19.59	-3.45	-0.08
GEO2	Niland	-8.40	-0.77	-0.29
GEO3	Heber	-4.37	-2.31	-0.15
GEO4	Sulfur Bank	-3.21	0.48	0.35
GEO5	Brawley North	0.63	0.00	-0.16
GEO6	Brawley East	-0.89	0.09	-0.15
GEO7	Medicine Lake	-0.07	-0.09	1.05
GEO8	Geysers	-0.43	0.11	0.21
GEO9	Salton Sea	0.14	-0.12	-0.14
HWD	Pacheco	0.08	-0.06	-0.06
HWD2	Medicine Lake	0.00	0.02	0.83
HWD3	LADWP	0.20	0.08	-0.18
HWD4	Altamont	-1.01	0.03	-0.41
HWD5	SDG&E	0.36	-0.02	0.09
HWD6	Imperial	0.10	-0.04	-0.06
HWD7	San Bernardino	-0.03	0.44	-0.04
HWD8	Lassen	-0.07	-0.29	-0.05
HWD9	Solano	0.10	0.51	0.44
HWD10	Riverside	0.22	0.07	-0.03
HWD11	Tehachapi	0.57	0.18	-0.03

The addition of new renewable resources requires new transmission lines, transmission line upgrades, transformer upgrades, and new substation transformers. The 33% penetration is not accomplished if these new transmission elements are not developed. Care must be taken when considering these new elements. For example, the fourth California Oregon Intertie (COI) line is

one long transmission line but has multiple elements as the line connects to multiple substations. Table 5-13 summarizes the number of new elements by voltage category for transmission lines and substation transformers. The table also includes the transmission line and substation transformers replaced in the 2010 Tehachapi case. The total number of new lines and transformers is the sum of the number of segments or transformers from each of the two cases. For example, there are 26 different 500 kV line segment upgrades, four in 2010 and 22 in 2020.

Table 5-13: 2010 Tehachapi Case Transmission System Upgrades Requirements

Voltage	2010 Line Segments	2020 Line Segments	2010 Transformers	2020 Transformers
500	4	22	2	9
230	7	38	5	18
161/138	0	2	0	0
115	49	49	10	5
Below 110	14	17	14	8
Total	**74**	**128**	**31**	**40**

The 2020 33% case with all of its projected transmission upgrades improves transmission reliability under first contingency (N-1) conditions while meeting the renewable penetration targets. The study does not consider the feasibility of constructing all of these elements. For an order of magnitude on the potential costs of the 500 kV and 230 kV transmission lines, the projected cost for the transmission lines and towers is $5.7 billion. The projected cost for the 40 transformers is $655 million. All costs are projected to be overnight costs in 2006 dollars. These costs do not include the transmission expansion costs for the 2010 Tehachapi case. The costs are projected for lines and towers only and do not include right-of-way, permitting, environmental studies, and other issues. The analysis at this point has not yet evaluated the hourly effects of the intermittency of renewables, only the effects at a single point in time.

5.4. Voltage Stability Problems

During the integration of renewables, some voltage instability is encountered as the renewable generation mix approaches the maximum penetration level. Certain renewable generation units did not reach their maximum generation capability (offset by decreasing natural gas non-RMR [Reliability Must Run] units) without causing a voltage collapse on the electrical grid.

The Power-Voltage (P-V) and Reactive Power/Voltage (QV) curve tool is used to determine an approximate location that a capacitor bank can be located to keep the system voltage stable and allow the full generation output of the desired unit. The voltage stability process involves

increasing a transfer of MW from a selected source of generators to another group of sink generators under Automatic Generation Control (AGC). Injection groups are defined to establish which units import the transfer and which units supply it. This is done to any renewable generator unit that does not reach the maximum target. Using an example from the 2010 XB 33% case, the method is demonstrated.

A Lassen wind unit rated at 650 MW at WESTWOOD 230 kV bus can not generate up to its maximum 650 MW generation capability without a voltage collapse occurring. The analysis is started by establishing two injection groups. The 650 MW capacity generator at WESTWOOD is set as the source group (export), with a starting output level well below the maximum capacity. The sink group consists of all the generators under AGC (natural gas non-RMR units) as the buyer (sink.) The P-V analysis determines that a maximum generation level of 562.5 MW can be achieved from the WESTWOOD unit prior to system failure.

Using the bus records table in PowerWorld Simulator, bus BIG BEND 115 kV is found to have the lowest voltage near the system collapse point. Once the bus is determined, a QV Curve analysis is completed. The plot is shown in Figure 5-3.

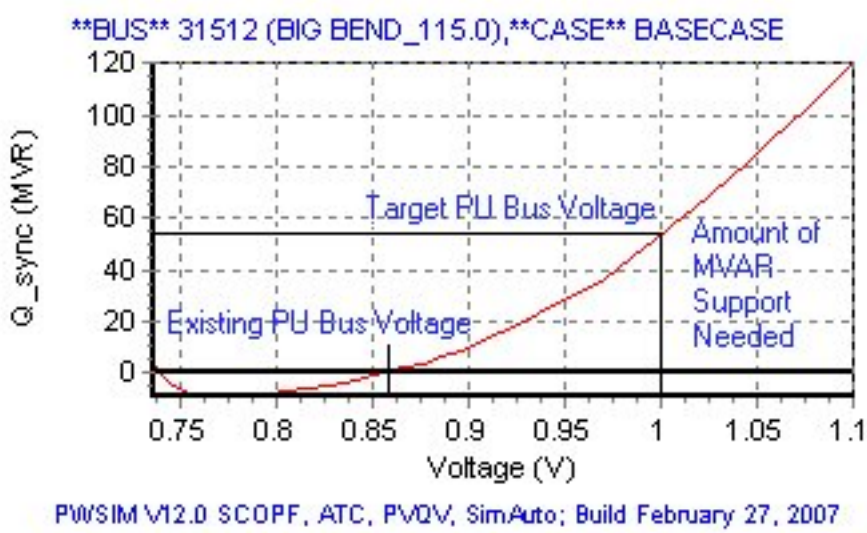


Figure 5-3: QV Curve, Big Bend 115 kV

A fictitious generator is placed at the Big Bend bus in order to create the QV curve. The voltage set-point of the fictitious generator is varied, and its voltage-ampere reactive (VAR) output is allowed to be any value needed to meet this voltage set-point. The vertical axis depicts the output of the fictitious generator in mega voltage-ampere reactive (MVAR) while the horizontal axis depicts the respective voltage under this condition. In the QV plot in Figure, the point where the curve intersects the X-axis is the current operating point of the system (0 MVAR). As the curve is traced down, the maximum level of MVAR load before system collapse is determined. Initially, the PV bus voltage level of BIG BEND is at 0.86 per unit at the WESTWOOD output level of 562.5 MW. By examining the curve to the left of the existing voltage point, it can be determined that if the voltage drops to approximately 0.79 per unit, the

system collapses. As the curve is traced up towards the ideal level bus voltage (ideal level is subjective, but assume 1.0 per unit for this example), the amount of MVAR support is roughly 50 MVAR, which is calculated by the coordinates of the curve at X = 1. Once the necessary MVAR support is added the P-V, QV analysis is repeated to verify the initial analysis.

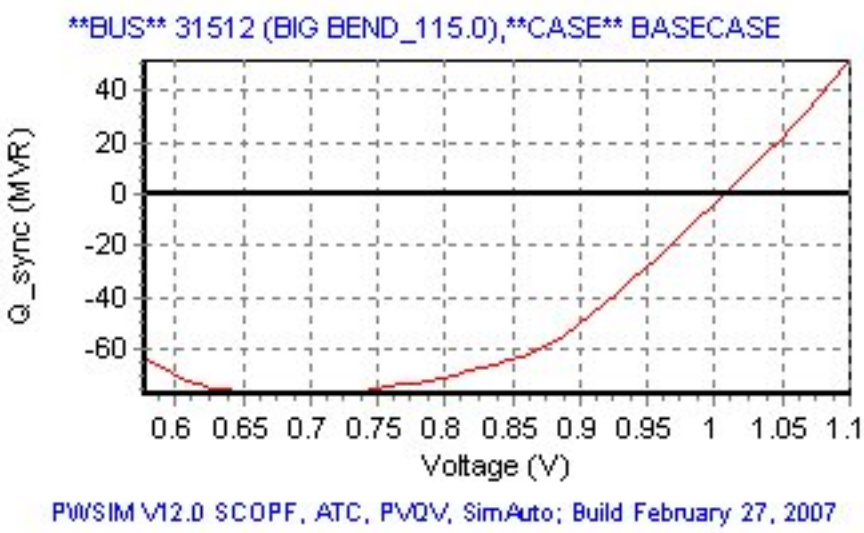


Figure 5-4: QV Curve, Big Bend 115 kV with 50 MVAR Capacitor Bank

The QV plot after the 50 MVAR capacitor bank (switched shunt) is added to the system is shown in Figure 5-4. The QV curve is offset by the capacitor bank which avoids system collapse. Once analysis on this bus is completed, the process is repeated as necessary to max out the generation at WESTWOOD. There are a total of two capacitor banks (switched shunts) that are necessary for system stability in the 2010 XB 33% analysis. These capacitor banks are shown in Table 5-14.

Table 5-14: Capacitor Banks Added to 2010 XB

Area Name	Bus Name	Bus Num	Bus Nom. kV	MVAR Size
PG & E	BIG BEND	31512	115	50
PG & E	BELDENTP	30261	230	200

When the 2020 case is built-out with a renewable penetration level of 33%, Table 5-15 summarizes the capacitor banks that are inserted into the system.

Table 5-15: Capacitor Banks Added to 2020

Area Name	Bus Name	Bus Num	Bus Nom. kV	MVAR Size
PG & E	BIG BEND	31512	115	80
PG & E	DAVIS	32104	60	80
PG & E	POE	30280	230	300

Area Name	Bus Name	Bus Num	Bus Nom. kV	MVAR Size
Imperial	MIDWAY	21045	230	400
PG & E	RIO OSO	30330	230	300
PG & E	ATLANTIC	30335	230	300
PG & E	GOLDHILL	30337	230	400

5.5. Maximum Renewable Penetration Analysis

This sensitivity analysis is designed to determine if a methodology can be developed to calculate the maximum renewable penetration level before an overload occurs. The 2010 Tehachapi case is used as a base case for the 2010 XA. The 2010 Tehachapi case includes a build-out of 20% renewables with an associated transmission expansion. Given the transmission expansion, the goal is to determine the additional renewable resources that can be added to fully utilize the surplus transmission capacity. The methodology used to determine the maximum penetration is the Available Transmission Capability (ATC). ATC determines the thermal capacity of the transmission network or selected lines to deliver additional power over these lines.

A linear analysis method is used for solving ATC on the 2010 XA case. The non-linear technique is not used because it requires an excessive amount of power flow solutions to examine a small number of elements under a small number of contingencies. Linear techniques only require a single calculation and provide approximate results in a fraction of the time.

Injection groups are defined to establish a buyer (sink) and seller (source). ATC determines how much power is transferred between the buyer and seller before an overload occurs in the power system. This procedure examines every possible combination to determine the maximum transfer possible for each pair of limiting elements and limiting contingencies.

AGC gas units are the buyers for the 2010 XA case. AGC gas units are not allowed to shut down and can shift generation output in relation to the seller. The renewable generation, both existing and newly identified from the 2010 33% renewable mix, are the sellers. The total generation output of the renewable sources is initially set at zero MW and ramps up according to the ATC simulation. This satisfies the ATC requirements and calculates the results for the summer, spring, and fall seasons.

Once the ATC parameters are developed, the analysis is completed for each season. For the summer 2010 XA case, ATC determines that the maximum level of penetration is 10,626 MW out of the potential 13,463 MW of renewables available. This equates to a total penetration of 26% as compared to a 20% penetration in 2010 and 33% in 2020. For the spring period, ATC determines that the maximum level of penetration is 10,111 MW out of the potential 13,463 MW of renewables available. This equates to a total of 24.8% penetration level of renewables in California. For the fall 2010 XA case, the potential capacity level of renewables is 11,484 MW. This is attributed to the fall case being an off-peak case at 2:00 AM. ATC determined that the

maximum level of penetration for the fall is 7,709 MW which is 22.2% penetration level of renewables. Table 5-16 shows the results of the penetration analysis.

Table 5-16: 2010 XA Maximum Renewable Penetration

	Summer (MW)	Spring (MW)	Fall (MW)
2010 Tehachapi Existing SVA MW	7,644	7,809	6,145
ATC Incremental Value (Only units from 33%)	2,982	2,302	1,564
Total for 2010 XA Achieved	10,626	10,111	7,709
33% MW Accelerated Target	13,463	13,463	11,484
Total % of CA In State Renewables	26.0 %	24.8 %	22.2 %

As verification, the strategic value analysis (SVA) is used to manually determine the maximum renewable penetration for the same conditions. This method is more of a trial and error process to find the maximum potential penetration. By this method, the summer maximum is 23% as compared to the 26% found by the automated process. The manual method is slightly lower than the ATC method because not all of the renewable locations used in the analysis were locations determined by the SVA, and therefore increasing some locations to full output actually reduced the ability to add more renewable generation somewhere else before experiencing a system overload.

6.0 IAP Transmission Intermittency Analysis Results

Analysis is performed to determine the unique system requirements imposed by wind as an intermittent resource. The transmission network must support a wide range of regional wind generation levels due to the difficulty of forecasting wind availability. If the transmission grid is expanded to meet 100% wind generation, the financial effects on electric ratepayers to support this transmission expansion are unacceptable. Simulation scenarios are based on planned installed resources and historically observed patterns of regional wind availability. This analysis represents an extension of the SVA, which examines the locational value of proposed renewable resources that is presented by DPC at the 2005 IEPR workshop in July 2005. The study seeks to isolate the unique aspects of wind as an intermittent and variable generation supply, namely the variability of transmission loading and the frequency and severity of transmission overloads. Although CSP and residential PV are also intermittent resources, the intermittency of these resources is not modeled due to a lack of forecasted or historical data.

The study evaluates the strength of the transmission system based on aggregate transmission planning metrics. Operational practices such as RAS can mitigate some of the system security vulnerabilities observed in this study, but are beyond the scope of the study (as well as detailed operations simulation and design of operational procedures.)

6.1. Objective

The objective is to determine which statistically plausible wind generation patterns cause transmission overloads, and the severity and duration of those overloads. The analysis extends the AMWCO metric across time to calculate an AMWhCO and AMWCO duration curves for each scenario. The results correlate the observed security effects and transmission loadings with regional wind production levels.

6.2. Background Material

Transmission and generation are planned in a coordinated manner to ensure generation resource adequacy and keep or improve existing levels of transmission grid security. Under this assumption, transmission grid security is defined by the amount and severity of transmission overloads that are caused by new wind projects with consideration of the intermittent nature of their outputs.

When a new wind project is built and generation is injected to the grid, the corresponding generator output creates a time-variant (intermittent) injection to the network, which on average is larger than the existing injection at the same point. The new project may therefore require transmission expansion to avoid introducing new security problems to the system. The determination of whether a project requires transmission expansion, and if so, the expansion level needed, depends on:

- The location of the project (the bus where the power is injected.)
- The size of the project (the maximum amount of MW injection.)

- The generation and load profile (determines the existing or base case flows in the grid) which are a function of time (peak or non-peak hour, season, etc.)
- The intermittency of the output function (how many hours the injection is above a certain MW level) for the project itself and for other intermittent resources throughout the system.

Projected wind conditions which consistently overload transmission elements for numerous hours suggest the need for transmission expansion or upgrade. Such transmission overloads can be present during normal (base case) operating conditions only or during contingency conditions.

6.3. Analysis Methodology

The state-wide wind regions are aggregated into five geographic regions that share common wind characteristics: San Gorgonio, Altamont, Tehachapi, Solano, and Pacheco. The reason for this aggregation is the unavailability to the DPC team of hourly forecasted wind generation for the 147 individual sites studied by GE Consulting. The DPC team uses the 2004 historical hourly wind data to aggregate generation over the five wind regions. The map in Figure 6-1 shows how the aggregation occurs. This aggregation is discussed later in this section.

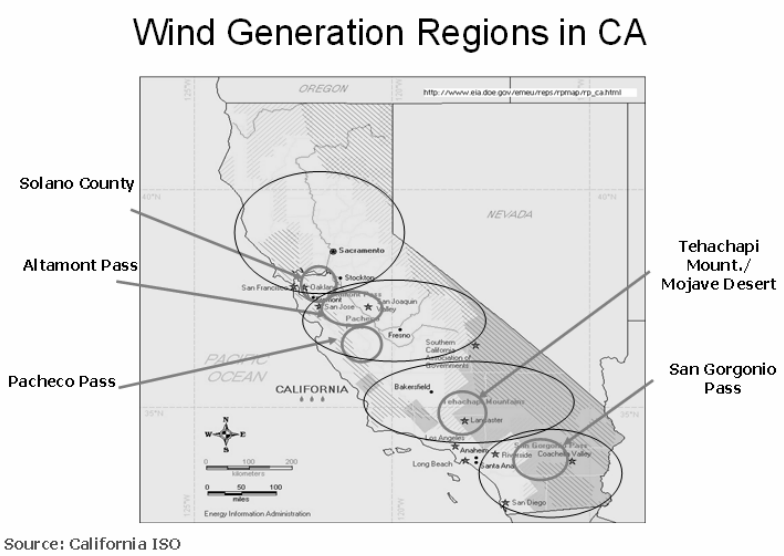


Figure 6-1: Wind Generation Regions

Three seasonal and time-of-day conditions are studied based on available power flow cases: spring peak, summer peak, and fall off-peak. For purposes of matching the available cases to compatible wind conditions, the seasons and time-of-day conditions are defined in Table 6-1.

Table 6-1: Time-of-Day Definitions for Hourly Wind Data

	Begin	End
Spring	April 8	June 3
Summer	July 9	September 3
Fall	October 8	December 3
On-peak	12:00 pm	6:00 pm
Off-peak	12:00 am	6:00 am

Hourly simulations are performed on power flow cases representing the 2006 summer peak and the three seasons for the 2010 Tehachapi, 2010 XB, and 2020 scenarios. The simulation for each season and scenario consists of 336 hourly samples, based on the periods defined by Table 6-1.

Simulation data points are generated using historically observed hourly capacity factors by region, season, and time of day. These data points are applied to the installed capacity by region in each case. This method captures the hourly volatility, correlation of capacity factors between regions, and periodic variation due to season and time of day. The historically observed hourly patterns are applied to the planned installed capacity for each studied time period. Variable wind generation is regulated by peaking resources located throughout the state, most of which are natural gas-fired, to serve the fixed load in each case. Load is held constant within each season and time-of-day power flow case to isolate the effects of variable wind. In an actual transmission study, the transmission planner includes the effects of load variability and intermittent resource variability in expansion and reliability planning decisions.

The transmission intermittency analysis uses historical wind data from five existing regions. A correlation analysis is completed to understand the inter-relationship of the five wind regions. The historical wind data reveals only minor correlations of wind production levels between each region. Altamont and Solano exhibit strong positive correlation, but other relationships are weak, especially in the summer and fall. Correlation coefficients between regions for each studied season are shown in Table 6-2, Table 6-3, and Table 6-4.

The correlation coefficient is a measure of the relationship between variables and varies from -1 to +1. A negative coefficient means the variables are inversely related, or that a high value of one tends to coincide with a low value of another. The higher the absolute value of the coefficient, the stronger the relationship between the two variables. A coefficient of zero means the variables are completely independent and the variation between them is purely random. With the exception of Altamont and Solano (which have strong positive correlation,) most regional production patterns are fairly independent of one another. The correlations between the five wind regions are dependent on the use of historical wind data and the assumption that all wind sites within each region are changing output following the same historical pattern. Site specific correlations between each individual wind site based on forecasted data are more accurate, but are not available to the DPC team at the time of this analysis. The relative independence of variation in northern and southern regions imparts significant variation in regional flows across the California transmission system. As described in the hourly intermittency analysis, high wind generation in southern California and low wind generation in

northern California during the fall time period have a significant impact on transmission reliability.

Table 6-2: Regional Wind Production Correlation, Summer Peak

	Altamont	Pacheco	San Gorgonio	Solano	Tehachapi
Altamont	-	0.2389	0.2956	0.8688	0.0771
Pacheco	0.2389	-	0.4977	0.2424	(0.3867)
San Gorgonio	0.2956	0.4977	-	0.3344	0.0731
Solano	0.8688	0.2424	0.3344	-	0.0934
Tehachapi	0.0771	(0.3867)	0.0731	0.0934	-

Table 6-3: Regional Wind Production Correlation, Spring Peak

	Altamont	Pacheco	San Gorgonio	Solano	Tehachapi
Altamont	-	0.7946	0.4688	0.8513	0.4855
Pacheco	0.7946	-	0.6289	0.6804	0.5428
San Gorgonio	0.4688	0.6289	-	0.3979	0.6904
Solano	0.8513	0.6804	0.3979	-	0.3978
Tehachapi	0.4855	0.5428	0.6904	0.3978	-

Table 6-4: Regional Wind Production Correlation, Fall Off-Peak

	Altamont	Pacheco	San Gorgonio	Solano	Tehachapi
Altamont	-	0.7456	0.1215	0.7345	(0.0091)
Pacheco	0.7456	-	0.1803	0.4920	0.1009
San Gorgonio	0.1215	0.1803	-	0.1262	0.3563
Solano	0.7345	0.4920	0.1262	-	0.0213
Tehachapi	(0.0091)	0.1009	0.3563	0.0213	-

The majority of the negative values are associated with the Pacheco wind region. With Pacheco wind capacity at 40 MW, the site has minimal impact on the system relative to the other regions. The spring period has the highest positive coefficients between all areas, while the fall and summer coefficients are generally smaller. Altamont and Solano have high coefficients in all seasons, as these sites are relatively close and contains large penetrations of wind.

An advantage of the historical capacity factors is that actual parameters of volatility, correlation, and periodic variation are imparted to the simulated data streams. However, the historically observed wind patterns contain limitations and require assumptions. The data does not incorporate improvements in turbine efficiency of new and future installed units. The capacity factors are recorded and aggregated across each of five geographic wind-producing regions and do not include granularity to specific sites, wind farms, or individual turbines. The study assumes that each facility in a wind-producing region operates at the same time-varying hourly capacity factor. Finally, several planned wind developments occur outside the existing five wind-producing regions of California. Since forecasts for the new sites are not available to the

DPC team for this analysis, the wind patterns for each new site are approximated with the historic wind patterns of the closest geographic region. Details of planned developments outside the existing wind producing regions are shown in Table. All existing and planned projects are assigned to one of the five wind producing regions by county as shown in Table 6-6.

Table 6-5: Planned Developments Outside Existing Wind-Producing Regions

Project/ Location	Capacity (MW)	Year Planned	Bus Number	Region Assigned
Los Angeles	200	2010	26160	Tehachapi
San Diego	90	2010	25902	San Gorgonio
San Diego	500	2010 XB/2020	22465	San Gorgonio
Imperial	600	2010 XB/2020	21915	San Gorgonio
Lassen (Westwood)	650	2010 XB/2020	31665	Solano
Shasta	130	2010 XB/2020	30105	Solano

Table 6-6: Assignment of Projects to Existing Wind Producing Regions

Wind Region	Counties
Altamont	Alameda, Contra Costa, San Joaquin
Pacheco	Merced
San Gorgonio	Imperial, Riverside, San Bernardino, San Diego
Solano	Lassen, Sacramento, Shasta, Solano, Yolo
Tehachapi	Inyo, Kern, Los Angeles, Tulare, Ventura

The system is simulated with each sample wind condition and transmission overloads are recorded. PowerWorld Simulator's time-step simulation feature is used to vary the wind generation for each hourly sample, record the line loading as a percentage of rating, and perform contingency analysis.

6.4. 2006 Summer Peak Analysis

6.4.1. Intermittency Impacts on Base Case Operation

Intermittency impacts are examined for the existing California wind resources on the 2006 system. The hourly summer peak capacity factors recorded in the 2004 data are applied to the 2006 case by wind region. The analysis shows transmission facilities tend to overload for certain levels of wind production in certain areas. Several lines in southern California tend to overload for high levels of Tehachapi production, including the 66 kV Tehachapi collector lines Antelope-Tap 81, Lancaster – Goldtown, Calcment – Tap 74, and Tap 76 – Tap 77. Congestion occurs for Tehachapi production over 600 MW, during approximately 3% of the simulated peak summer hours. The loading patterns are exemplified by the heavy black line in Figure 6-2 and Figure . This congestion can be addressed by the planned upgrade of the Tehachapi transmission to 230 kV.

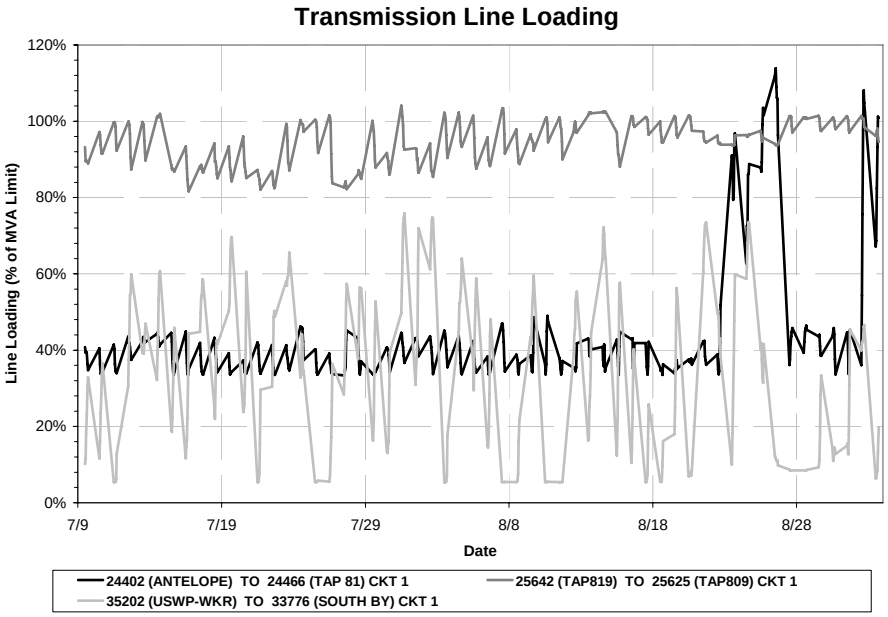


Figure 6-2: Transmission Line Loadings for 2006 Hourly Intermittency Simulation

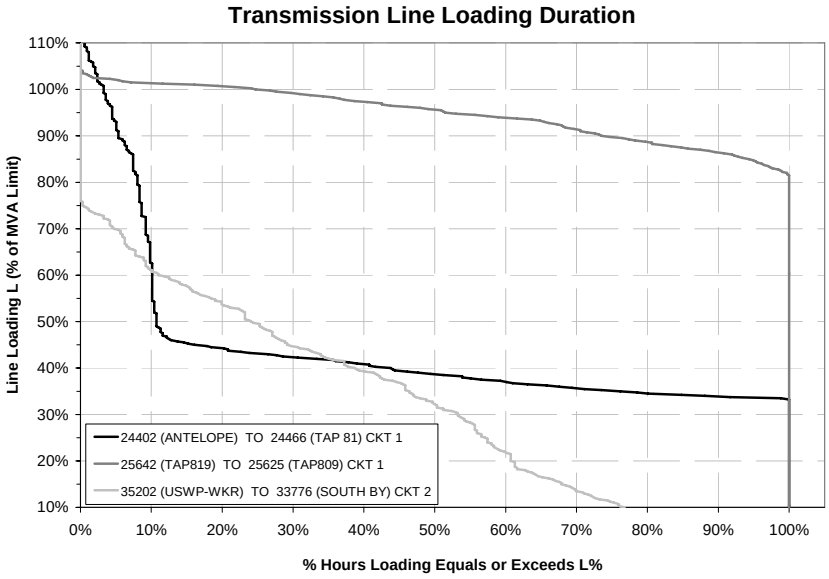


Figure 6-3: Transmission Line Loading Duration for 2006 Hourly Intermittency Simulation

A group of 115 kV transmission lines in southern California are adversely impacted by low wind production in San Gorgonio. The 115 kV Mirage to Tamarisk line in Riverside County is overloaded during approximately 25% of the peak hours and experiences significant variability, with strong inverse correlation to San Gorgonio production. The high dependence of line loading on the wind output suggests that The Mirage to Tamarisk line is a good candidate for upgrade. The line loading pattern is illustrated by the medium gray line in Figure 6-2 and Figure 6-3.

Another notable loading pattern is observed on several 60 kV lines that deliver the Altamont generation to the system, as shown by the light gray line in Figure 6-2 and Figure 6-3. These lines tend to be heavily loaded with high wind production at Altamont and Solano. None of these lines is loaded beyond 80% of their rating during the 2006 simulation, but may require upgrading if more capacity is installed at Altamont or Solano. Peak production during the simulation included 574 MW between these two regions.

6.4.2. Intermittency Impacts on Contingency Operation

Hourly contingency analysis is performed on the 2006 Summer Peak case to measure the impact of the intermittent wind resources on the System AMWCO.

The total simulated System AMWhCO over 336 summer peak hours is 5,575,000 megawatt-hours (MWh), with an average System AMWCO of 16,591 MW. The System AMWCO duration curve is shown in Figure 6-4..

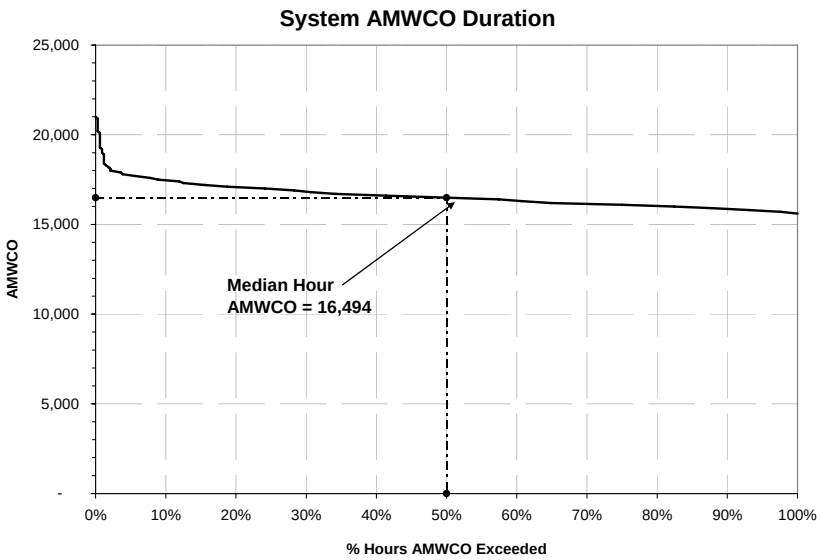


Figure 6-4: System AMWCO Duration, 2006 Summer Peak

The System AMWCO exceeds 18,000 MW for 2.1% of the simulated hours. No single region's wind production is strongly correlated with high System AMWCO, though the hours that produce AMWCO greater than 18,000 MW occur during high production at Tehachapi (over 600 MW.) This condition is depicted by the steeply sloping left-hand portion of the plot in Figure 6-4.

There are 200 transmission elements that are overloaded at least once during the hourly contingency simulation and contribute to the System AMWhCO. Eleven of these produced at least 100,000 AMWhCO and together account for nearly 38% of the total. Details are presented in the contour map of Figure 6-5 and in Table 6-7.

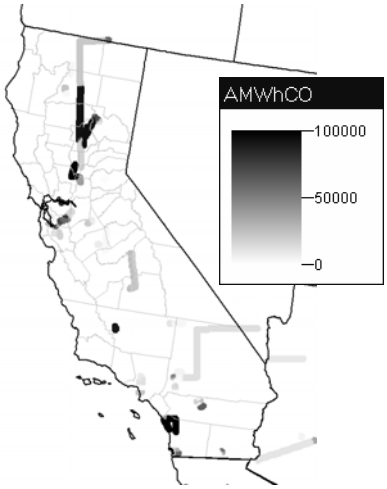


Figure 6-5: AMWhCO Contours, 2006 Summer Peak

The AMWhCO values are not to be taken as the magnitude of the capacity additions needed to solve transmission overloads. The value is a measure of the transmission security, similar to the AMWCO value. In the case of the AMWhCO, the value is calculated over multiple hours, resulting in a magnitude which is significantly greater than the AMWCO, which is calculated at one single point in time.

Table 6-7: Major AMWhCO Contributions, 2006 Summer Peak

"From Bus" Number	"To Bus" Number	AMWhCO	% of Total
22232	24131	897,264	16.1%
22260	22844	141,041	2.5%
37520	37546	138,289	2.5%
37520	37546	138,289	2.5%
31712	31714	128,068	2.3%
31696	31708	123,217	2.2%
31714	31708	111,714	2.0%
31704	31702	110,194	2.0%
31696	31704	109,144	2.0%
31702	31718	106,238	1.9%
31718	30301	100,485	1.8%
Subtotal		2,103,943	37.7%

The line at the top of the list (22232-24131) overloads during outages of certain nearby lines, or during the loss of Encina generators. The greatest overload occurs during outages of 500 kV multi-section lines through North Gila, which cause large redistributions of flows on the 230 kV network. The overloads occur for every hour in the simulation and vary between 2,498 and 2,965 MW. The wind production pattern does not affect whether the line becomes overloaded, but does affect the magnitude of the overload. The 230 kV Escondido – Talega line exhibits

similar characteristics and is shown by the heavy black line in Figure 6-6.

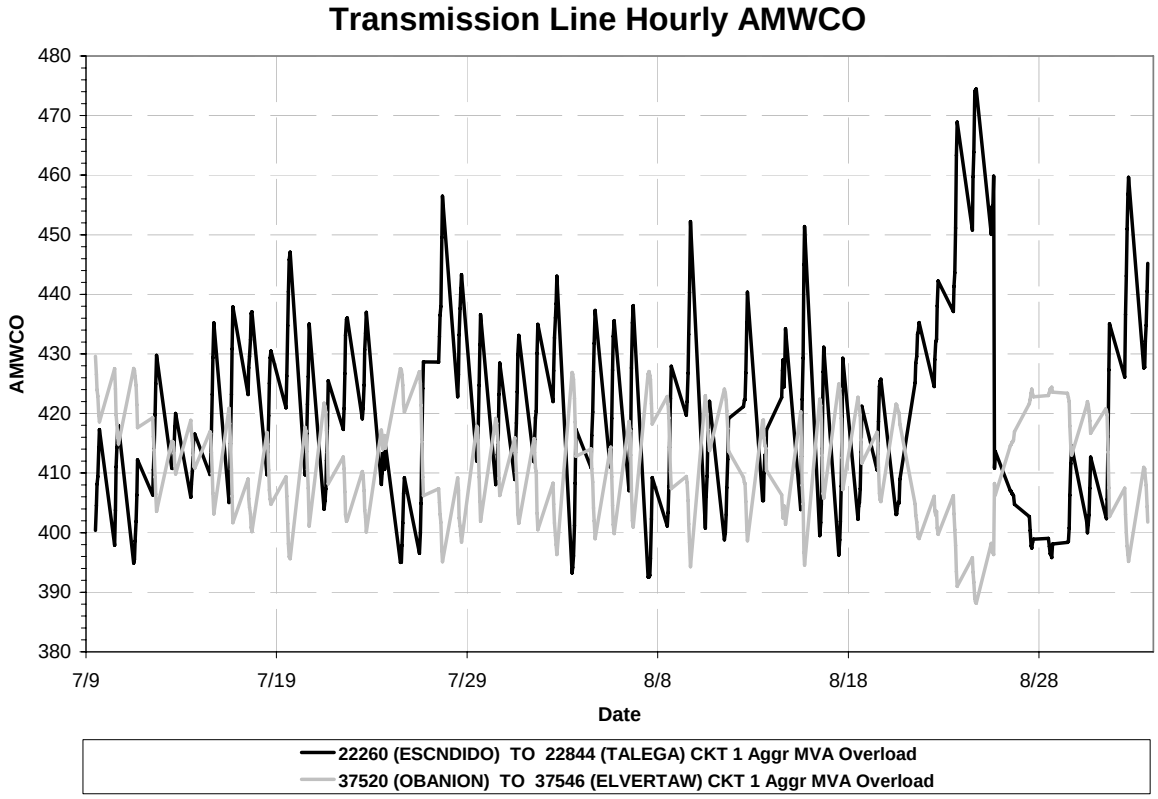


Figure 6-6: Hourly AMWCO, 2006 Summer Peak

The remaining transmission lines that experience at least 100,000 AMWhCO are in the PG&E area. The magnitudes of the hourly AMWCO for all lines except the 60/230 kV Table Mountain transformer (31718-30301) are negatively correlated with Altamont and Solano wind production. The highest overloads occur when Altamont and Solano production are light. However, all lines are also overloaded by at least 298 MW for every hour of the simulation, regardless of the wind production. The most volatile overloads in this group are the parallel 230 kV Obanion – Elverta circuits. These are loaded to 96% of their limits in the base case. A negative correlation can be observed in Figure6-6 between the Obanion – Elverta hourly AMWCO, shown by the light gray line, and the Escondido – Telega AMWCO plot (heavy black line.)

Several lines in Southern California contribute to the System AMWhCO primarily during hours of high Tehachapi production. As discussed previously, these overloads can be mitigated by Tehachapi transmission upgrades to 230 kV and later to 500 kV.

6.5. 2010 and 2020 Analysis

In addition to the 2006 Summer scenario, hourly simulations are performed on the Spring peak, Summer peak, and Fall off-peak cases for the 2010 Tehachapi, 2010 XB, and 2020 scenarios.

6.5.1. Base Case Congestion Trend

An examination of the hourly base case transmission loadings for each season and scenario provides insight about transmission vulnerabilities and upgrades required to support an increasing portfolio of intermittent resources over time. Specific transmission elements that exhibit vulnerability during one or more scenarios, along with the correlations between loading and regional wind outputs, are examined to better understand the conditions that produce congestion.

Summer Peak

The summer peaks are characterized by extreme system load and moderate wind production. The median wind capacity factor varies between 22% for the 2010 Tehachapi scenario and 24% for the 2010 XB and 2020 scenarios.

In the 2010 Tehachapi scenario, the variability of transmission loading and frequency of transmission overloads during the simulation periods are greatly reduced from the levels observed in the 2006 summer simulation. Specific lines which exhibit vulnerability in 2006 are greatly improved.

Several factors contributed to the improvement, which occurs despite a substantial increase in wind capacity:

1. Transmission expansion modeled into the 2010 cases.
2. Transmission expansion at the 500 kV level into the Tehachapi region.
3. Operation of additional renewable resources, which when sited at favorable locations, is demonstrated to reduce congestion and improve reliability in the SVA Study.

The highest base case transmission loading variability occurs on the low-voltage collector network, similar to the 2006 summer simulation observations. However, the extreme variability observed at Antelope in 2006 is greatly dampened in 2010, an apparent improvement due to the planned Tehachapi upgrades. Prolonged thermal overloads on low-voltage facilities can be avoided by local remedial action schemes or circuit breaker switching. The system as modeled in 2010 seems better suited to absorb the variable thermal loadings imparted by variable wind production.

Several planned transmission upgrades are included in the 2010 XB and 2020 scenarios, beyond those in the 2010 Tehachapi scenario. However, the simulations reveal that additional upgrades may be necessary to support increasing intermittent wind production.

Several transmission lines exhibit vulnerability during the summer peak hourly simulations. Transmission loading worsens with each scenario, though several modeled upgrades mitigate some conditions. Two lines in the low-voltage Altamont collector network are frequently overloaded with the increasing wind production capacity modeled in the Altamont region. Base case load duration curves for the Herdlyn transformer and the Herdlyn – Tracy 70 kV line are shown in Figure 6-7.

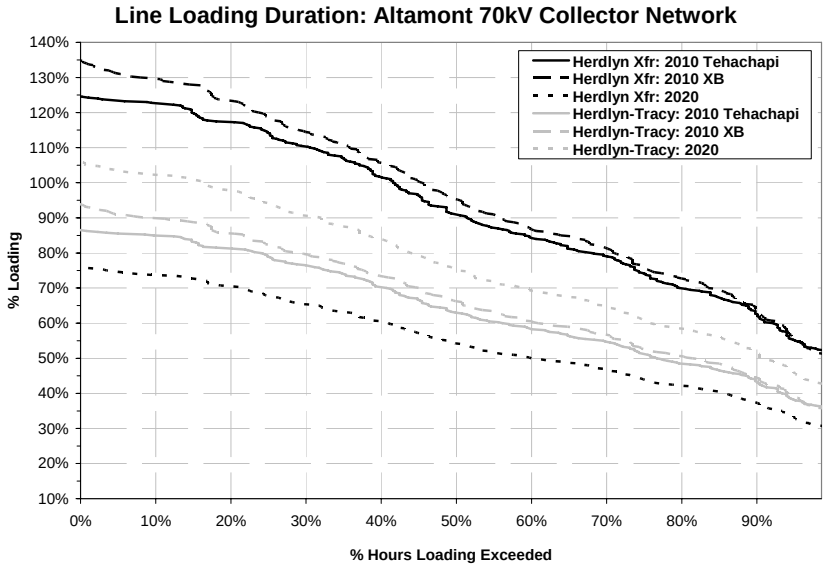


Figure 6-7: Summer Peak Loading Duration Trend for Altamont 70 kV Collector Network

The Herdlyn transformer is overloaded in over 40% of the simulation hours in the 2010 Tehachapi scenario, and worsens with the expansion of wind capacity in the 2010 XB scenario. The Herdlyn transformer rating is increased for the 2020 simulation. The Herdlyn – Tracy line is progressively more overloaded with each subsequent scenario. Rating increases are not modeled for the line, though they could be necessary to support the 2020 plan.

Flow on both elements exhibits high variability and strong negative correlation with Altamont and Solano wind production. The elements experience their highest loading when the regions' wind is lightest. A load pocket develops when regional wind production is light, with the element loadings worsening as load is increased over time.

Alternative mitigation strategies include the development of new dispatchable resources in the region to compensate for periods of light Altamont wind production, or implementation of RAS to relieve the local network under appropriate conditions. Simply opening the overloaded lines provides relief in some circumstances, but also creates other problems, such as low voltages or overloading on the lines remaining in service. Due to the frequent overloading of the Altamont collector network, it can require upgrading or the expansion of higher voltage transmission to the area if Altamont wind capacity is increased as planned.

The Ramon – Mirage 230kV circuit exhibits a notable increase in loading between the 2010 Tehachapi and the 2010 XB scenario, though it is not overloaded in the summer peak hourly base case simulations. A second parallel circuit is added for 2020, but the upgrade is desirable to provide higher security margins during the 2010 XB scenario. The Ramon – Mirage loading is strongly negatively correlated with San Gorgonio wind output, meaning it tends to experience highest loading during periods of light San Gorgonio wind production. The load duration curves for the circuit are shown in Figure 6-8. The flatness of the curves reveals that loading variability is relatively light, despite the strong correlation with San Gorgonio wind production.

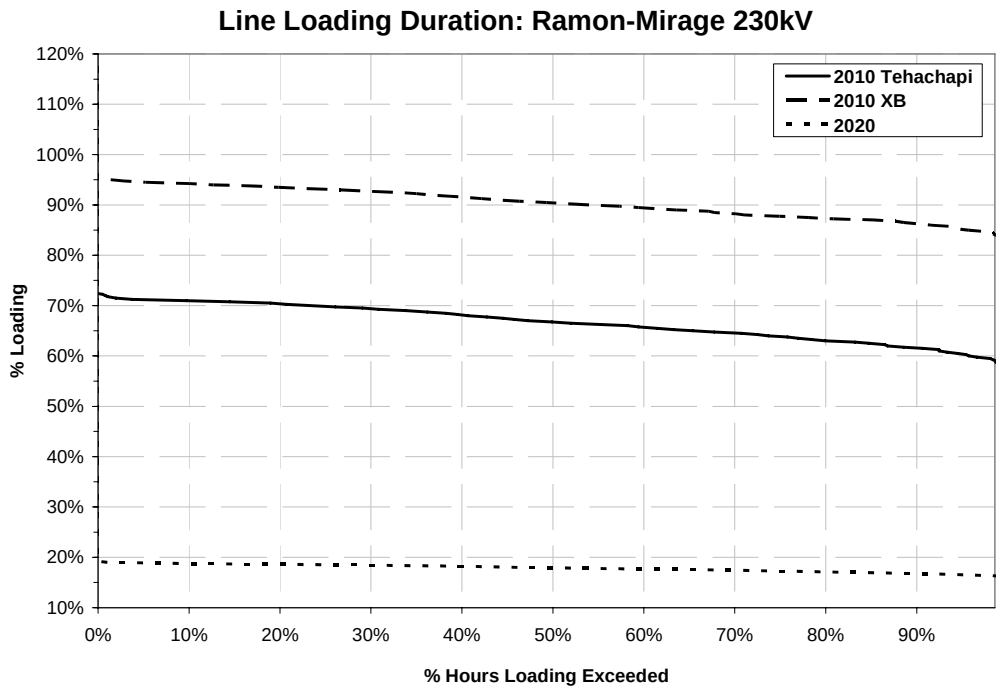


Figure 6-8: Summer Peak Loading Duration Trend for Ramon-Mirage 230 kV

The Warner Springs – Rincon 69 kV line, part of the low voltage network northeast of San Diego, exhibits a dramatic increase in loading during the 2010 XB scenario. The 2020 model includes a rating upgrade, which may be desirable for 2010 XB as well. The primary cause for the increase in stress is the addition of new solar capacity on the 69 kV network. However, loadings are exacerbated by wind production at San Gorgonio. Periods of high loading may require curtailment of wind or solar. The load duration curves for the circuit are shown in Figure 6-9.

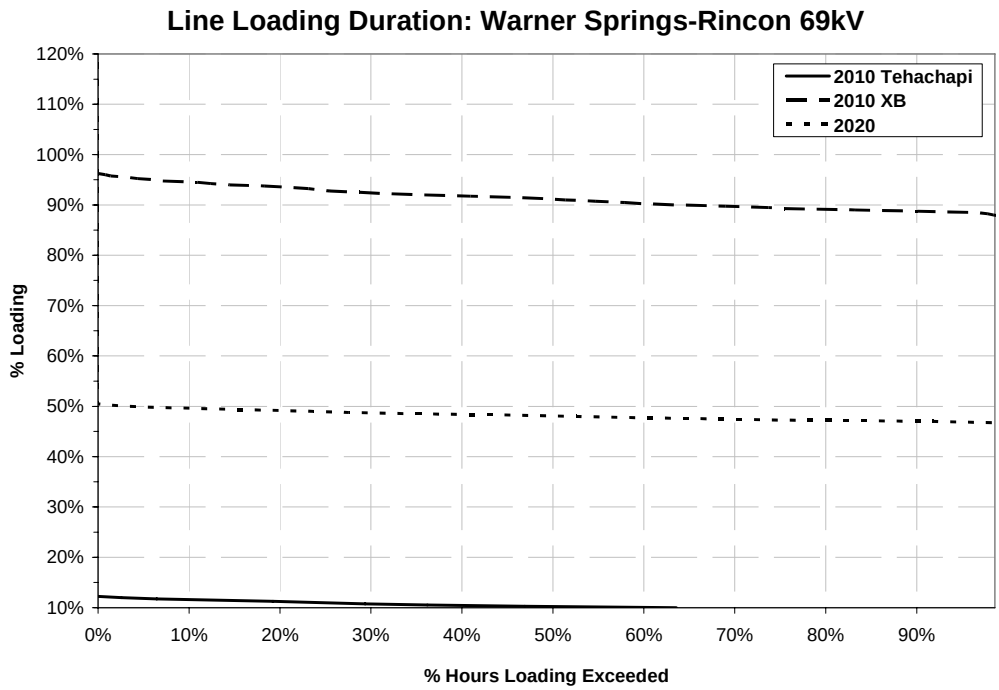


Figure 6-9: Summer Peak Loading Duration Trend Warner Springs-Rincon 69 kV

The Folsom 230/115 kV transformer experiences overloading during the 2020 summer peak simulation, though it is loaded at a constant level throughout the 2010 Tehachapi and 2010 XB simulations. The 2020 scenario includes the expansion of natural gas-fired capacity at Folsom. Such resources are important in compensating for low-wind production periods at Altamont and Solano. The simulation suggests the need for expanding capacity of the transformer. The load duration curves are shown in Figure 6-10.

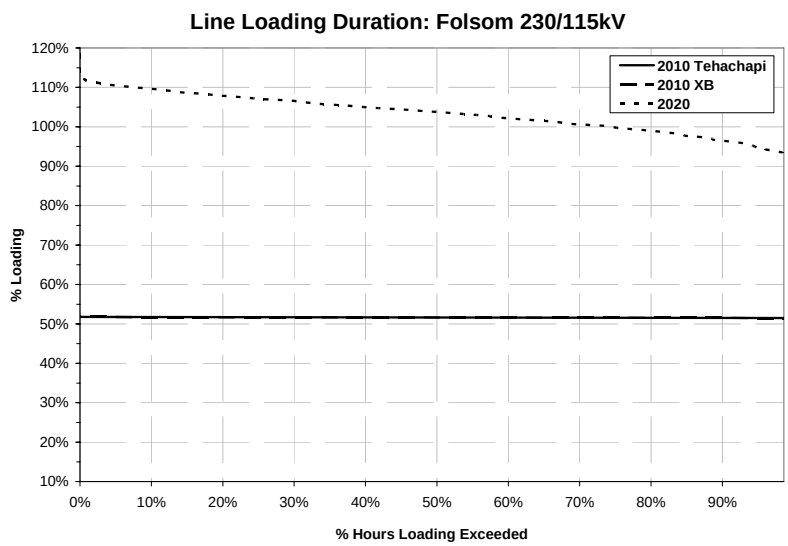


Figure 6-10: Summer Peak Loading Duration Trend for Folsom 230/115 kV

Spring Peak

The spring peaks are characterized with heavy wind production, with median system wind production capacity factors varying between 38% and 40%, depending on the scenario. Several lines and other elements of the system exhibit vulnerability during the spring peak hourly simulations.

Portions of the Altamont collector network exhibit behavior similar to that observed during the summer peak simulations. Load duration curves for the Herdlyn transformer and Herdlyn – Tracy line for the spring peak simulations are shown in Figure 6-11. Upgrading of existing lines or introducing higher voltage transmission can be beneficial to support expansion of intermittent wind resources in Altamont, similar to the summer peak simulation results.

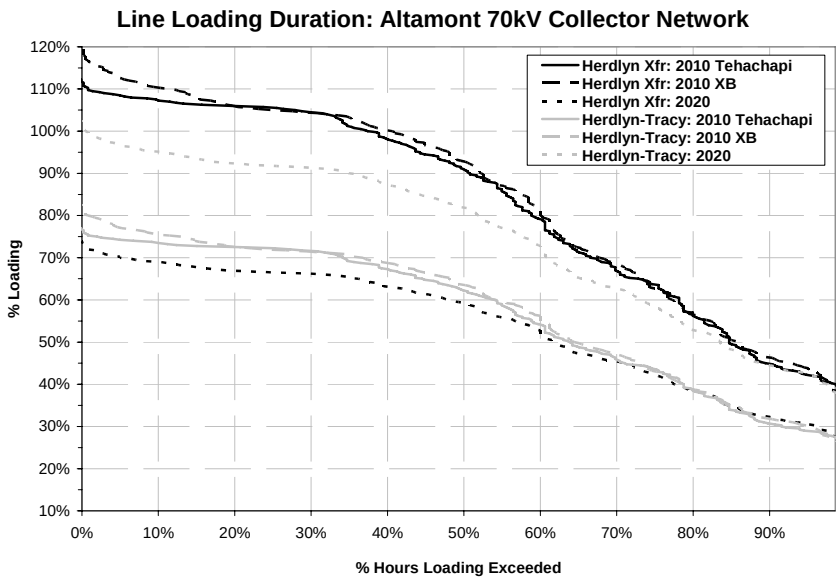


Figure 6-11: Spring Peak Loading Duration Trend for Altamont 70 kV Collector Network

The Ramon – Mirage 230kV circuit exhibits a notable increase in loading between the 2010 Tehachapi and the 2010 XB scenario, again similar to the summer peak simulation results. The circuit overloads during approximately 20% of the hours of the 2010 XB simulation. The 2020 addition of a parallel circuit can improve loading during the 2010 XB scenario. The load duration curves for the circuit are shown in Figure 6-12.

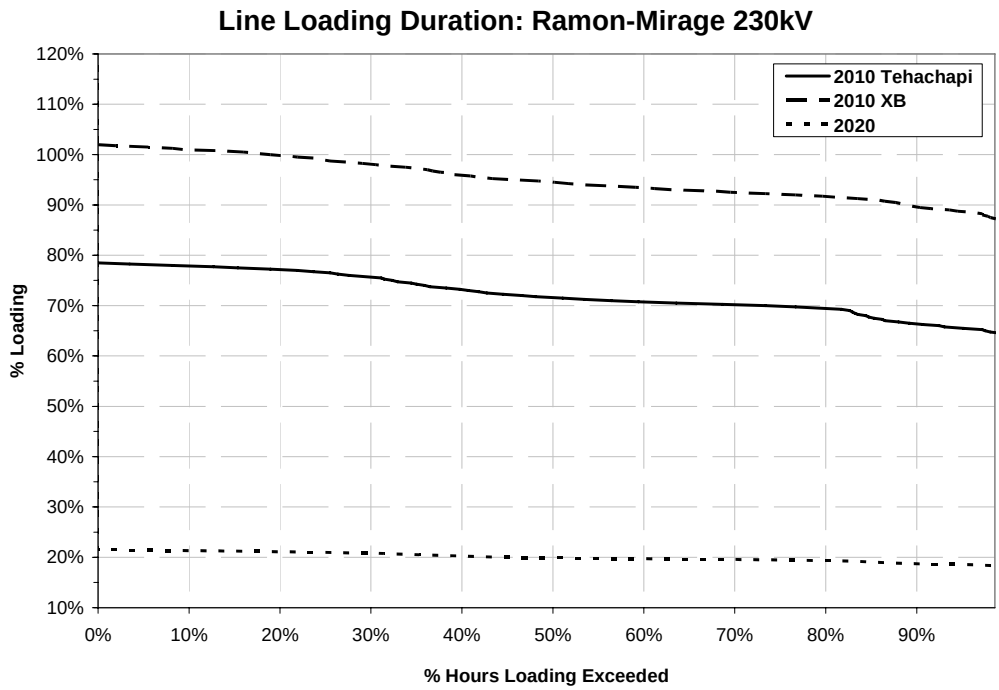


Figure 6-12: Spring Peak Loading Duration Trend for Ramon-Mirage 230 kV

The Table Mountain 500/230 kV transformer exhibits increasing variability with the 2010 XB spring peak hourly simulation and a sharp increase in flow with the 2020 simulation. Generating flows exhibit a strong positive correlation with Solano wind production, which includes 650 MW of proposed capacity at Westwood in Lassen County for 2010 XB and 2020. Though capacity is adequate to support all base case hourly production mixes, the transformer can become vulnerable to a further increase in nearby wind capacity. The load duration curves for the circuit are shown in Figure 6-13.

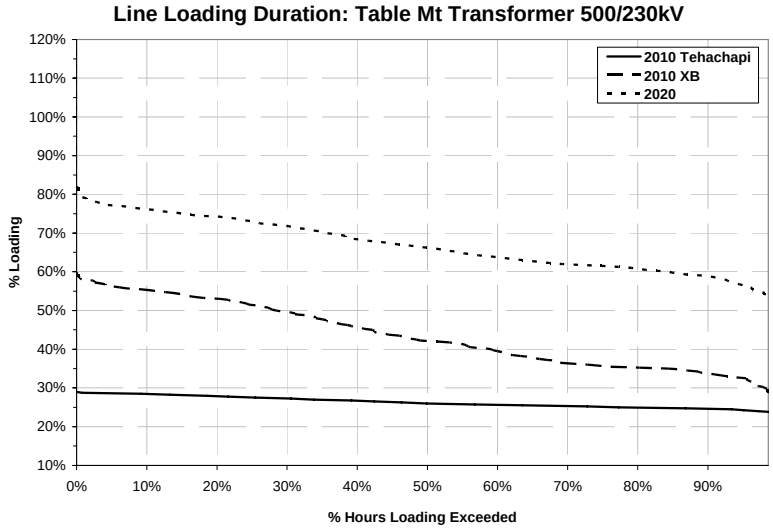


Figure 6-13: Spring Peak Loading Duration Trend for Table Mt. Xfer 500/230 kV

The Warnerville – Wilson 230 kV line exhibits moderate loading variability and increasing flows with each successive scenario. Flows are adequate to support the full range of hourly base case wind production patterns, but increases in capacity can cause congestion on the path. Flows are negatively correlated with wind production at San Gorgonio and Tehachapi. The load duration curves for the circuit are shown in Figure 6-14.

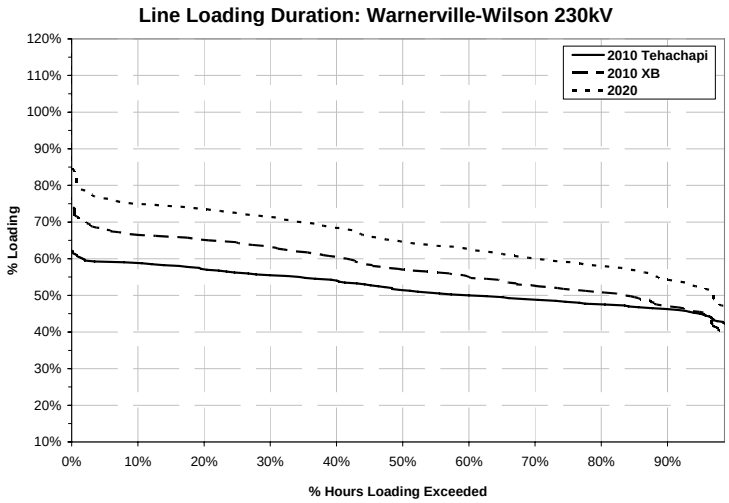


Figure 6-14: Spring Peak Loading Duration Trend for Warnerville-Wilson 230 kV

Fall Off-Peak

The behavior and characteristics of the fall off-peak simulation are distinctly different from those of the summer and spring peaks. The system loading in the fall off-peak period is extremely light, while peak wind production is higher than other seasons. The highest simulated Tehachapi capacity factor is observed in the fall off-peak simulation. The combination of high wind and light load leads to a much higher percentage of load being served by intermittent and variable resources.

The fall off-peak conditions generally support a wide range of regional wind outputs, causing minimal transmission congestion compared to the spring and summer peak models. However, there are a few notable trends.

The Ramon – Mirage 230 kV circuit exhibits modest base case overloading in the 2010 XB scenario. The circuit's variability is light, but its loading has a strong negative correlation with San Gorgonio wind output. This result is similar for the same circuit in the other studied seasons. The load duration curves for the circuit are shown in Figure 6-15.

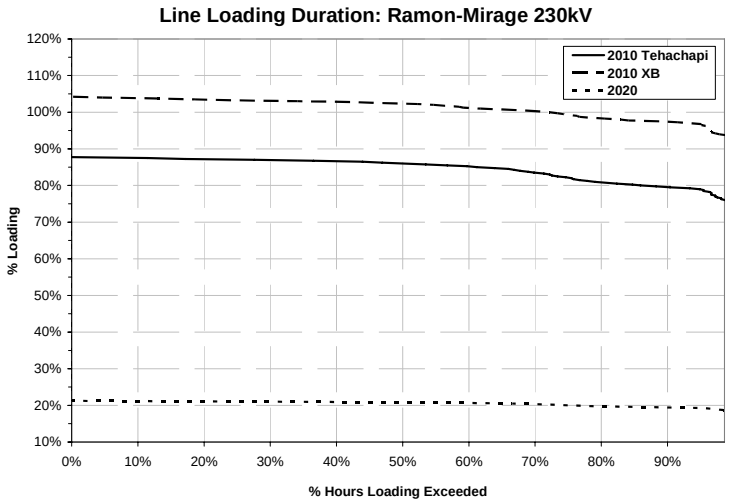


Figure 6-15: Fall Off-Peak Loading Duration Trend for Ramon-Mirage 230 kV

The additional renewable production required to support the 33% RPS goal in the 2010 XB scenario causes a higher base loading on the transmission line, resulting in overloads during approximately 73% of the simulation hours. The 2020 scenario includes an upgrade to this circuit, along with other transmission upgrades. The results suggest that the line can also be upgraded earlier to support 33% renewable penetration in 2010. An alternative to transmission expansion can be coordinated dispatch of conventional resources near San Gorgonio to respond to periods of low wind production in the region.

The Rosamond – Tap 52 circuit exhibits some vulnerability in the 2020 simulation. The line is part of the 66 kV collector network near Antelope and its loading exhibits positive correlation with wind production in the Tehachapi region. The load duration curves for the circuit are shown in Figure 6-16.

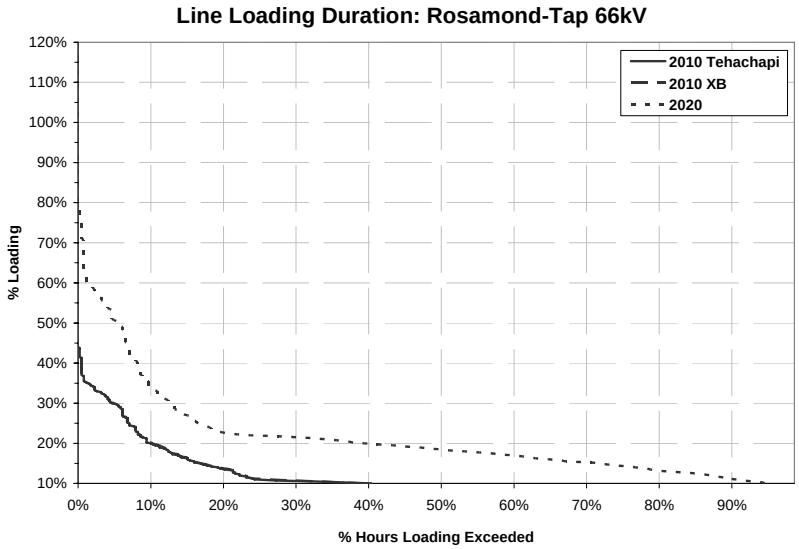


Figure 6-16: Fall Off-Peak Loading Duration Trend for Rosamond-Tap 66 kV

The loading is essentially identical in the 2010 Tehachapi and 2010 XB scenarios, but increases significantly in the 2020 scenario. Though the circuit never becomes overloaded in the base case simulations, expansion can be required to support increasing wind production in the Tehachapi region. Future combined cycle development at Antelope can relieve flows on the line. The inclusion of connections between the existing Tehachapi collector network and the 500 kV expansion planned for the region may also be desirable.

The fall simulation reveals base case overloads on the 500 kV network, even on the Tehachapi upgrades, though such overloads are confined to periods of peak Tehachapi production and low Altamont and Solano production. Such patterns can create abnormally high south to north flows through Midway, Los Banos, and Tracy, unless additional transmission upgrades are made, wind production is curtailed, or additional gas units are dispatched in the north to counter the effect. The results indicate that a series capacitor on the planned 500 kV Tehachapi – Midway circuit is highly sensitive to Tehachapi wind production. The load duration curves for the circuit are shown in Figure 6-17.

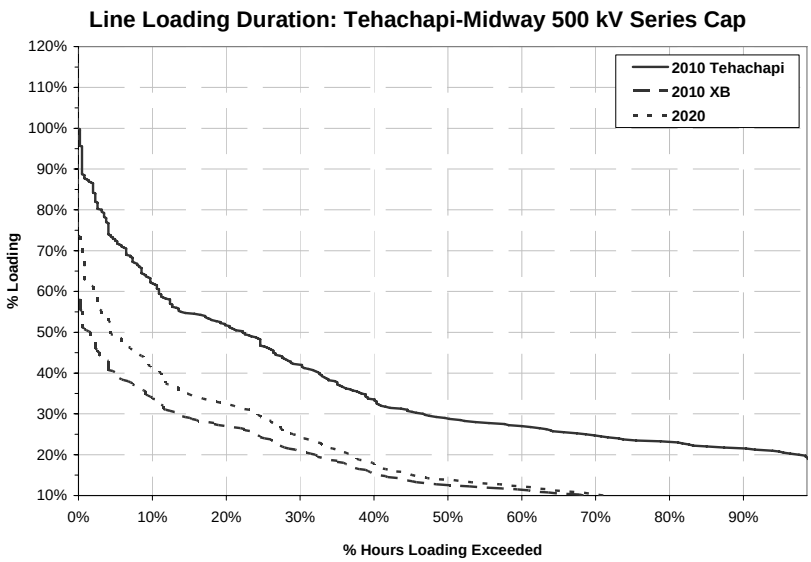


Figure 6-17: Fall Off-Peak Loading Duration Trend for Tehachapi-Midway 500 kV Series Cap

The rating of the capacitor provided by the Tehachapi Collaborative Study Group is 1,848 MVA. The 2010 Tehachapi model uses this capacity, though its capacity is doubled for the 2010 XB and 2020 scenarios, alleviating the vulnerability in those simulations. The simulation suggests that the planned capacity can be increased for the 2010 Tehachapi scenario as well, unless operational measures, such as bypassing the capacitor, relieve the congestion.

6.5.2. Contingency Congestion Trend

Hourly contingency analysis is performed on the summer peak, spring peak, and fall off-peak seasons of the 2010 Tehachapi, 2010 XB, and 2020 scenarios to measure the impact of the intermittent wind resources on AMWCO.

Figure 6-18 shows the trend in System AMWCO for each season and scenario. The vertical candlestick lines depict the standard deviation or variability of the hourly System AMWCO for each season and scenario. The standard deviation is a statistical measure of how much the System AMWCO varies from hour to hour. The diamond markers indicate the extreme minimum and maximum hourly System AMWCO for each season and scenario.

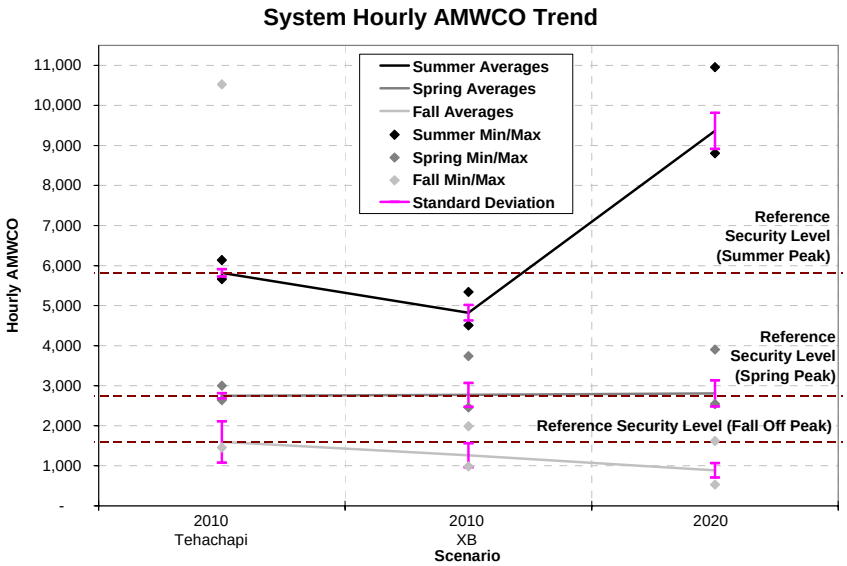


Figure 6-18: System Hourly AMWCO Trend

The addition of renewable capacity generally improves average hourly System AMWCO, though the hourly variability tends to grow during the spring and summer peaks. The higher variability reflects the increasing capacity and energy production from intermittent wind resources. The improvement in fall averages reflects the incremental transmission expansion modeled in each successive scenario, along with the net positive locational benefit of the renewable resources identified in the SVA study. However, the spring average remains fairly constant over all scenarios and the summer average worsens for the 2020 scenario. These trends reflect limits in available transfer capability when renewable production and load reach extreme levels. However, even the summer 2020 simulation shows a marked improvement in System AMWhCO from the summer 2006 simulation.

Figure 6-19 shows the corresponding System AMWCO duration curves for each season and scenario. Both figures reveal the marked improvement in the fall seasons over time and renewable penetration. The variability of transmission loading generally increases from the 2010 Tehachapi scenario to the 2010 XB scenario, owing to the increased production from variable wind resources. Increasing variability is most pronounced in the spring and summer peaks, for which the 2010 Tehachapi duration curves are relatively flat and the 2010 XB and 2020 duration curves revealed increasing slope.

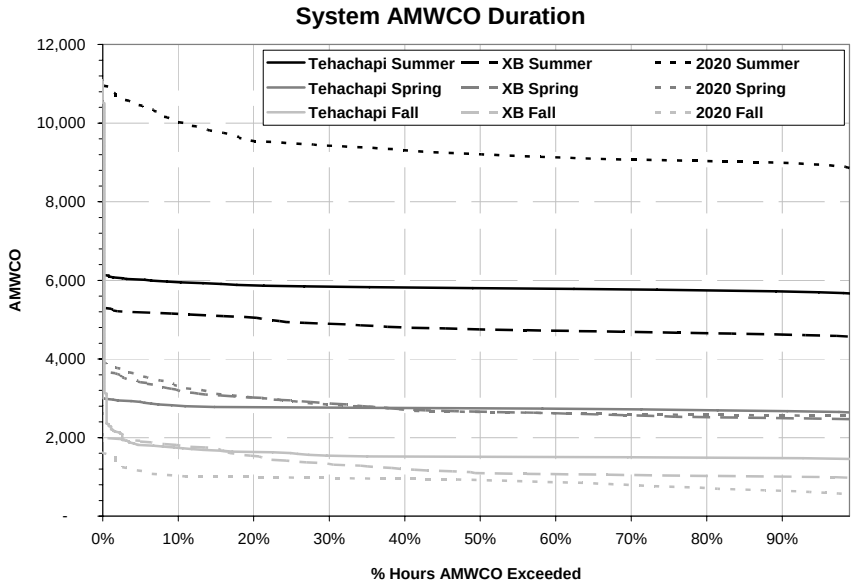


Figure 6-19: System AMWCO Duration, All Seasons Trend

The variability caused by greater reliance on intermittent resources can require mitigation with special protection schemes that limit the magnitude of hour-to-hour changes in wind production or curtail wind if production exceeds the capacity of the transmission network to deliver wind energy to the load. Fast-responding load-following resources such as simple cycle gas turbines may be needed and be strategically re-dispatched by region in response to varying wind conditions. For example, transmission overloads caused by low wind production in one region and high generation in another region can be mitigated by increasing conventional resources in the same region when wind production drops. The summer peak reveals that the transmission network requires further expansion by 2020 to maintain reliability during heavy loading and high renewable power production. An alternative may be to supplement some renewable production with conventional dispatchable resources during the heaviest load periods.

Summer Peak

The summer peak simulations reveal a reduction in contingency overloading from the 2010 Tehachapi to the 2010 XB scenarios. The system AMWhCO experiences a sharp increase between the 2010 XB scenario (33% renewable energy penetration in 2010) and the 2020 scenario. The increase seems to be driven largely by the increase in load rather than the small incremental increase in renewable energy from the 2010 XB case to the 2020 case.

Figure 6-20 shows transmission branch AMWhCO contour maps of each successive scenario. Darker areas reflect higher levels of contingency overloading. The overloading patterns are very similar in 2010 Tehachapi and 2010 XB. In 2020, the contingent overloads become less focused but more widespread. Imports from the Northwest are lower in the 2020 case and an extra circuit is added to the COI, which contributes to the relief seen in that part of the system. Penetration of renewable and intermittent resources, as a share of load, is greatest in the 2010 XB scenario.

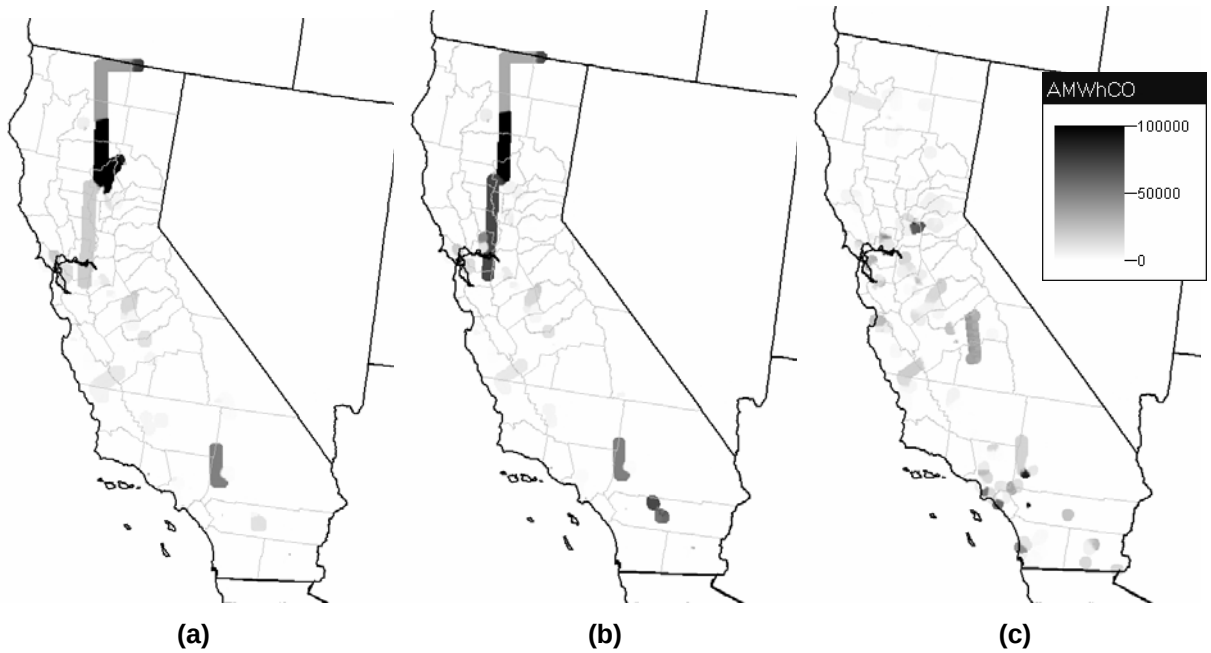


Figure 6-20: AMWhCO Contours, Summer Peak: (a) 2010 Tehachapi, (b): 2010 XB, (c) 2020

Figure 6-21 shows the trend in System AMWCO duration curves for the Summer Peak scenarios.

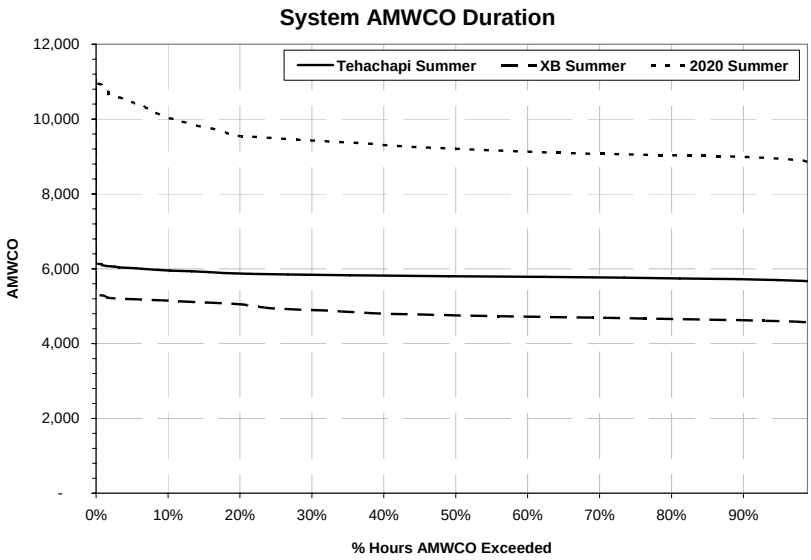


Figure 6-21: System AMWCO Duration Trend, Summer Peak

Table 6-8 reveals several interesting statistics about contingency overloading for the summer peak scenarios. The total number of transmission elements that overload at least once during the simulation is almost constant in 2010 Tehachapi and 2010 XB, but increases sharply in 2020. However, variability of the hourly System AMWCO, as measured by the standard deviation as a percentage of the average, increases sharply with 2010 XB, but increases only slightly from

2010 XB to 2020. This result suggests that the increased penetration of renewable resources has an adverse effect on loading variability in 2010 XB, though the locational value of such resources has a positive effect on average loading.

Table 6-8: System AMWCO Trend Statistics, Summer Peak

	2010T	2010XB	2020
Total No. of CTG Overloaded Elements	131	132	231
Hourly AMWCO Average	5,818	4,822	9,364
Hourly AMWCO Std. Deviation/Average	1.6%	4.0%	4.8%
Hourly AMWCO Std. Deviation/Load	0.15%	0.31%	0.61%
Hourly AMWCO Std. Deviation/Wind Production Std. Deviation	9%	11%	26%
Wind Production Average/Load	2.8%	5.0%	4.3%
Wind Production Std. Deviation/Load	1.7%	2.8%	2.4%
Hourly AMWCO Correlation with Regional Wind Production			
Altamont	(0.20)	0.62	(0.15)
Pacheco	0.08	0.17	(0.16)
San Gorgonio	0.64	0.60	0.02
Solano	(0.18)	0.70	(0.23)
Tehachapi	0.53	0.24	0.30

Average wind production and wind variability relative to load increases sharply between 2010 Tehachapi and 2010 XB. Both decrease slightly between 2010 XB and 2020. However, the variability of the hourly System AMWCO increases in 2020. Variability of hourly System AMWCO increases with respect to load and to variability of wind production, with each successive scenario.

Also of interest is the fact that hourly System AMWCO has a stronger correlation with most regions' wind production in 2010 Tehachapi and 2010 XB than in 2020. This suggests that the increase in System AMWhCO in 2020 is driven primarily by changes in system load. However, some individual transmission elements still exhibit strong correlations to regional wind production levels, as illustrated in the following subsections. Intermittency is expected to remain a challenging issue in 2020, as evidenced by increased variability of AMWCO as shown in Table 6.8 and increased slope on the left-hand side of the duration curve shown in Figure 6-19, relative to the other scenarios.

2010 Tehachapi Scenario

The total simulated System AMWhCO for the Tehachapi scenario is 1,955,000 MWh, with an average System AMWCO of 5,818 MW. These figures show a marked improvement over the 2006 summer peak simulation (recall the 2006 summer peak System AMWhCO of 5,575,000 MWh,) owing to the transmission upgrades and penetration of SVA renewable resources. The System AMWCO duration curve is shown in Figure 6-22.

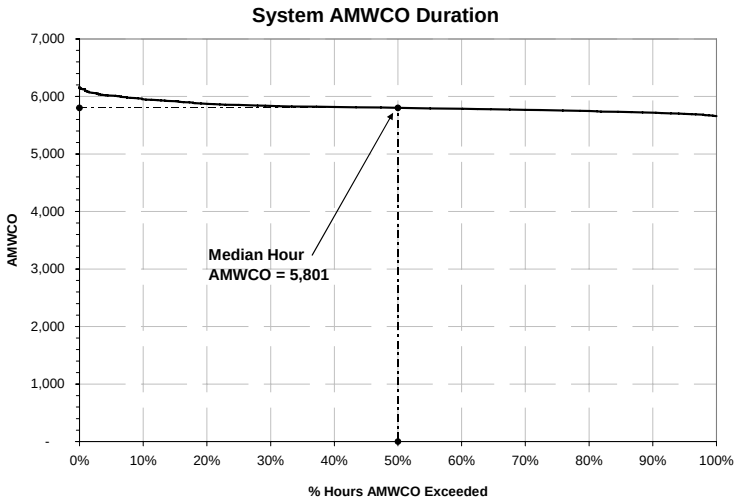


Figure 6-22: System AMWCO Duration, 2010 Tehachapi Summer Peak

System AMWCO is loosely correlated with high production in San Gorgonio and Tehachapi and low production in Altamont and Solano. The 2010 Tehachapi case exhibits an improvement in the average contingency overload, and does not exhibit the extreme variability of System AMWCO seen in the 2006 summer case, which experiences high System AMWCO during periods of peak Tehachapi production.

For the 2010 Tehachapi case, 131 transmission elements are overloaded at least once during the hourly contingency simulation and contribute to the System AMWhCO. Twelve of these produce at least 48,000 AMWhCO and together account for 50% of the total. Several contingent transmission overloads are correlated with Tehachapi production, while others tend to overload at constant levels regardless of wind production. A measure of variability is provided as the Standard Deviation divided by the Average. Details are presented in Table 6-9. "Corr." indicates any correlation greater than 0.7 +/- between hourly AMWCO and hourly regional wind production.

Table 6-9: Major AMWhCO Contributions, 2010 Tehachapi Summer Peak

"From Bus" Num.	"From Bus" Name	"To Bus" Num.	"To Bus" Name	Ckt	Xfr	kV	AMWh-CO	% of Total	Std. Dev./ Avg.	Corr.
31516	WYANDJT2	31512	BIG BEND	2	No	115	118,439	6.1%	0.1%	T +
31482	PALERMO	31516	WYANDJT2	2	No	115	115,385	5.9%	0.1%	T +
30018	ROUTAB21	30019	ROUTAB22	2	No	500	112,125	5.7%	3.1%	
31488	GRIZ JCT	31512	BIG BEND	1	No	115	111,719	5.7%	0.1%	T +
30016	ROUTAB11	30017	ROUTAB12	1	No	500	110,612	5.7%	3.2%	
31486	CARIBOU	31488	GRIZ JCT	1	No	115	88,583	4.5%	0.1%	T +
40687	MALIN	40692	MALROU21	2	No	500	75,383	3.9%	6.1%	
30526	PITSBG D	30528	DEC PTSG	1	No	230	54,792	2.8%	0.1%	T +
30526	PITSBG D	30528	DEC PTSG	2	No	230	54,792	2.8%	0.1%	T +
24128	S.CLARA	24127	S.CLARA	4	Yes	230	51,289	2.6%	1.8%	T +

"From Bus" Num.	"From Bus" Name	"To Bus" Num.	"To Bus" Name	Ckt	Xfr	kV	AMWh-CO	% of Total	Std. Dev./ Avg.	Corr.
24701	KRAMER	24085	LUGO	1	No	230	49,673	2.5%	11.4%	T -
24701	KRAMER	24085	LUGO	2	No	230	49,673	2.5%	11.4%	T -
Subtotal							992,465	50.8%		

Notable for high variability and correlation to Tehachapi output are the parallel 230 kV Kramer to Lugo circuits. An alternative to upgrading the circuits can be to closely coordinate regional gas-fired production with Tehachapi wind.

2010 XB Scenario

From the hourly contingency simulation, the System AMWhCO for the summer peak case is 1,620,000 MWh, with an average System AMWCO of 4,822 MW. These figures show an improvement over the 2010 Tehachapi simulation, owing primarily to increased penetration of favorably located SVA renewable resources. The 2010 XB scenario also includes some transmission expansion beyond the 2010 Tehachapi scenario, including the Sunpath project in Imperial Valley. The System AMWCO duration curve is shown in Figure 6-23.

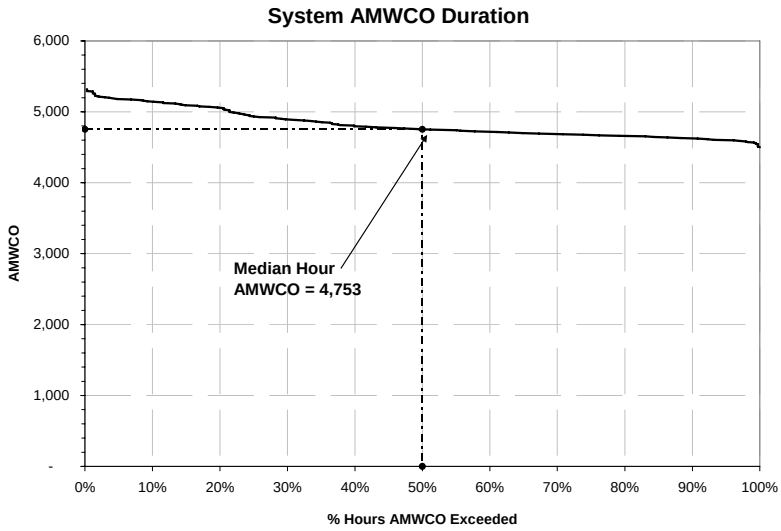


Figure 6-23: System AMWCO Duration, 2010 XB Summer Peak

System AMWCO is loosely positively correlated with production in Solano, Altamont, and San Gorgonio and fairly independent of Tehachapi production. The relationships are distinct from that of the 2010 Tehachapi summer peak, which are negatively correlated with Solano and Altamont. Although the average contingency overloading improves over the 2010 Tehachapi case, the hourly variability increased.

There are 132 transmission elements that overload at least once during the hourly contingency simulation and contribute to the System AMWhCO. Of the 132 transmission elements, 13 produce at least 45,000 AMWhCO and together account for 50% of the total. Several contingent

transmission overloads are correlated with various regions' wind production, while others tend to overload at constant levels regardless of wind production. A measure of variability is provided as the Standard Deviation divided by the Average. Details are presented in Table 6-10.

Table 6-10: Major AMWhCO Contributions, 2010 XB Summer Peak

"From Bus" Num.	"From Bus" Name	"To Bus" Num.	"To Bus" Name	Ckt	Xfr	kV	AMWh-CO	% of Total	Std. Dev./ Avg.	Corr.
30018	ROUTAB21	30019	ROUTAB22	2	No	500	103,973	6.4%	9.1%	A,S-
30016	ROUTAB11	30017	ROUTAB12	1	No	500	102,500	6.3%	9.2%	A,S-
30041	TABTES11	30043	TABTES12	1	No	500	71,942	4.4%	28.9%	A,S+
21007	COACHELV	24804	DEVERS	1	No	230	71,685	4.4%	8.3%	SG-
40687	MALIN	40692	MALROU21	2	No	500	70,813	4.4%	16.7%	S-
21007	COACHELV	21076	RAMON	1	No	230	53,338	3.3%	5.5%	SG-
24128	S.CLARA	24127	S.CLARA	4	Yes	230	51,361	3.2%	2.4%	T+
24701	KRAMER	24085	LUGO	1	No	230	49,695	3.1%	14.8%	T-
24701	KRAMER	24085	LUGO	2	No	230	49,695	3.1%	14.8%	T-
24065	HINSON	24064	HINSON	1	Yes	230	47,935	3.0%	0.0%	
24065	HINSON	24064	HINSON	4	Yes	230	47,935	3.0%	0.0%	
21076	RAMON	24806	MIRAGE	1	No	230	47,198	2.9%	9.7%	SG-
30460	VACA-DIX	30472	PEABODY	1	No	230	45,801	2.8%	112%	A,S+
Subtotal							813,871	50.2%		

Most of the major AMWhCO contributors listed in the table exhibit high variability and correlation to one or more region's wind production. The parallel 230 kV Kramer to Lugo circuits correlates inversely with Tehachapi production, as they do with the 2010 Tehachapi summer peak simulation. The 2010 XB summer case reveals negative correlation between two parallel Round Mountain – Table Mountain 500 kV circuits and Altamont and Solano wind production. These circuits are overloaded at some level during all hours of the simulation. However, higher production levels at Altamont and Solano tend to relieve the flow on these lines that carry imports from the Northwest. The higher variability of contingent overloads in the 2010 XB case relative to the 2010 Tehachapi case is reflective of the much larger installed capacity of wind. Combined, the Altamont and Solano regions have 2.5 times as much wind capacity than in the 2010 Tehachapi case.

The series capacitor at Malin along the Malin – Round Mountain circuit exhibits negative correlation with Solano production. This capacitor has a lower capacity than the line that it serves, which suggests that the data in the power flow case could be inaccurate. An upgrade of the series capacitor capacity can relieve congestion along the path if the data in the case is accurate.

The Table Mountain – Tesla and Vaca Dixon – Peabody circuits, which are south of Round Mountain – Table Mountain, exhibit high variability and positive correlation with Altamont and Solano wind production. Mitigation of overloads may be accomplished by increasing the

capacity of these circuits or through remedial action schemes that coordinate peaking and load following resources in the area with the regional wind production. However, the fact that circuits to the north exhibit the opposite correlation may present a challenge for remedial action schemes, especially during periods of high imports on the COI. Mitigating contingent overloads on one group of circuits can coincidentally increase overloads on another. This behavior is driven by the proposed Lassen wind site, which is following the Solano hourly wind production pattern. Upgrades may ultimately be required if variable wind capacity and production are allowed to increase at the rate simulated in the 2010 XB cases.

The Coachella Valley – Devers and Ramon – Mirage 230 kV circuits exhibit inverse correlations with San Gorgonio production. Mitigation may also be accomplished through remedial action schemes to increase dispatchable natural gas production in the San Gorgonio area during times of low San Gorgonio wind production.

2020 Scenario

The total simulated System AMWhCO for the 2020 scenario is 3,146,000 MWh, with an average System AMWCO of 9,364 MW. The figures reveal a reversal of the average improvement observed with the 2010 XB scenario, due primarily to an increase in system load. The System AMWCO duration curve is shown in Figure 6-24.

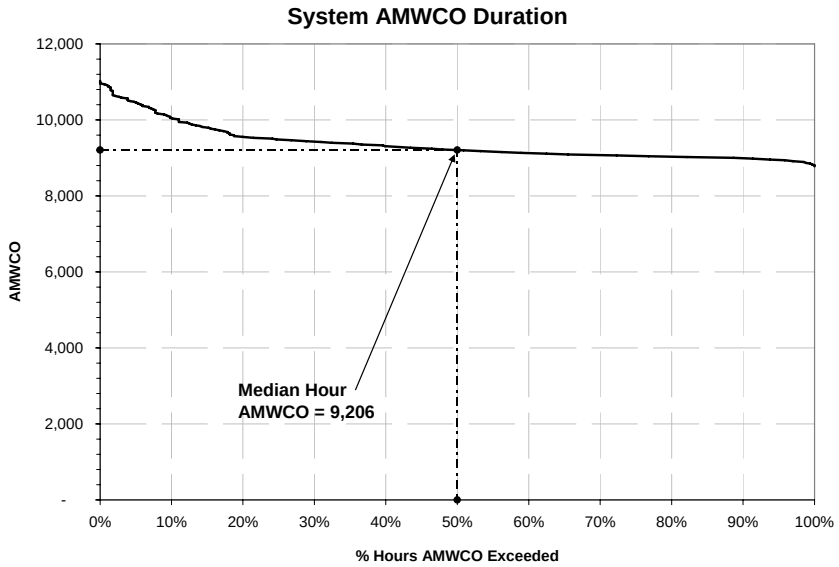


Figure 6-24: System AMWCO Duration, 2020 Summer Peak

System AMWCO is not strongly correlated with any region's wind production, unlike the 2010 Tehachapi and 2010 XB scenarios. However, the hourly variability of the 2020 System AMWCO still increases, indicating that intermittency poses challenges with increasing capacities.

For the 2020 case, 231 transmission elements are overloaded at least once during the hourly contingency simulation and contribute to the System AMWhCO. Of the 231 transmission elements, 25 produce at least 40,000 AMWhCO and together account for 50% of the total, a sharp increase over the similar demographic for the 2010 XB scenario. Many of the major

individual contributors have very low hourly variability and are not strongly correlated with any region wind production. The elements tend to overload at fairly constant levels, regardless of wind production. The majority that varies are correlated with Tehachapi or San Gorgonio production. Details are presented in Table 6-11.

Table 6-11: Major AMWhCO Contributions, 2020 Summer Peak

"From Bus" Num.	"From Bus" Name	"To Bus" Num.	"To Bus" Name	Ckt	Xfr	kV	AMWh-CO	% of Total	Std. Dev./ Avg.	Corr.
24151	VALLEYSC	24229	VALLEY-S	3	Yes	500	150,774	4.8%	0.0%	
24086	LUGO	24226	LUGMOH11	1	No	500	91,215	2.9%	18.9%	SG-
37013	ORANGEVL	37018	WHITEROK	1	No	230	90,013	2.9%	5.4%	T-
24151	VALLEYSC	24176	valley4i	4	Yes	500	75,385	2.4%	0.0%	
24229	VALLEY-S	24176	valley4i	4	Yes	115	75,385	2.4%	0.0%	
30526	PITSBG D	30528	DEC PTSG	1	No	230	75,190	2.4%	15.9%	T-
30526	PITSBG D	30528	DEC PTSG	2	No	230	75,190	2.4%	15.9%	T-
37001	CAMINO S	37012	LAKE	1	No	230	65,787	2.1%	7.9%	T-
37018	WHITEROK	37028	CORDOVA	1	No	230	63,319	2.0%	7.0%	T-
24151	VALLEYSC	24160	VALLEYSC	1	Yes	500	62,281	2.0%	0.0%	
24151	VALLEYSC	24160	VALLEYSC	2	Yes	500	62,281	2.0%	0.0%	
24044	ELLIS	24197	ELLIS	1	Yes	230	61,297	1.9%	0.0%	
33600	HERDLYN	37582	TRACY YG	1	No	70	55,612	1.8%	256.7%	
24044	ELLIS	24197	ELLIS	4	Yes	230	55,420	1.8%	0.0%	
24074	LA FRESA	24073	LA FRESA	4	Yes	230	53,381	1.7%	1.1%	T+
24044	ELLIS	24197	ELLIS	2	Yes	230	53,357	1.7%	0.0%	
24074	LA FRESA	24073	LA FRESA	2	Yes	230	52,785	1.7%	1.1%	T+
24074	LA FRESA	24073	LA FRESA	3	Yes	230	50,872	1.6%	1.1%	T+
30875	MC CALL	30877	MCCALL2M	2	Yes	230	50,793	1.6%	5.9%	T+
34370	MC CALL	30877	MCCALL2M	2	Yes	115	50,793	1.6%	5.9%	T+
30460	VACA-DIX	30472	PEABODY	1	No	230	45,615	1.4%	112.3%	A,S+
32412	ATLANTIC	30335	ATLANTC	1	Yes	230	43,293	1.4%	0.0%	A,S+
22192	DOUBLTTP	22648	PENSQTOS	1	No	138	43,103	1.4%	14.2%	SG+
22192	DOUBLTTP	22922	MIRA SOR	1A	No	138	43,103	1.4%	14.3%	SG+
24303	BIG CRK3	24235	RECTOR	1	No	230	40,854	1.3%	1.0%	T-
	Subtotal						1,587,098	50.4%		

Most of the transmission facilities that exhibit high levels of AMWhCO and high correlation between contingency overloads and regional wind production patterns in the 2020 simulation differ from those in the 2010 Tehachapi and 2010 XB simulations. One exception is the Vaca Dixon – Peabody 230 kV circuit, which is highly variable and correlates with Altamont and Solano production.

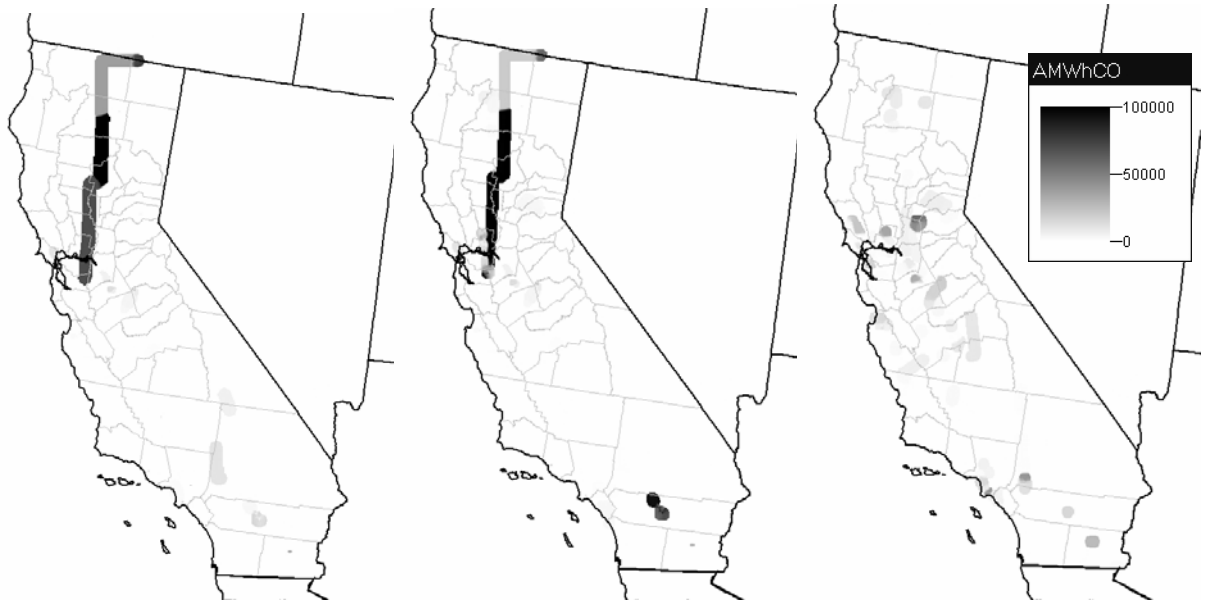
The Lugo – Mohave 500 kV series capacitor exhibits inverse correlation with San Gorgonio wind production. The element is another instance of a series capacitor having a significantly lower rating than the transmission line that it compensates. The capacitor may require upgrading if it cannot be bypassed or otherwise protected with remedial action schemes during periods of high loading.

The 230 kV circuits that connect the natural-gas fired Delta Energy Center to the Pittsburg substation also exhibit high contingency overloading. The circuits may require upgrades to support the planned capacity of the Delta Energy Center.

Finally, the 115 kV lines between Mira Sor, Doublet, and Penasquitos near San Diego exhibit high variability and positive correlation with San Gorgonio output. The proposed Imperial and San Diego high wind sites tend to slightly increase loading on these lines. However, several nearby natural gas facilities have a much larger effect and may be adjusted to relieve these facilities as needed.

Spring Peak

The spring peak simulations reveal a slight increase in average contingency overloading from the 2010 Tehachapi scenario to the 2010 XB scenario. Similar to the summer peak simulations, variability increases with each successive scenario. Figure 6-25 shows transmission branch AMWhCO contour maps of each successive scenario. The spring peak 2010 XB contour shows areas of increasing intensity similar to the summer peak contours. The 2020 contour shows some reductions in intensity, but overloads are more widespread with the increase in system load.



(a) (b) (c)

Figure 6-25: AMWhCO Contours, Spring Peak: (a) 2010 Tehachapi, (b): 2010 XB, (c) 2020

Figure 6-26 shows the trend in System AMWCO duration curves for the spring peak scenarios.

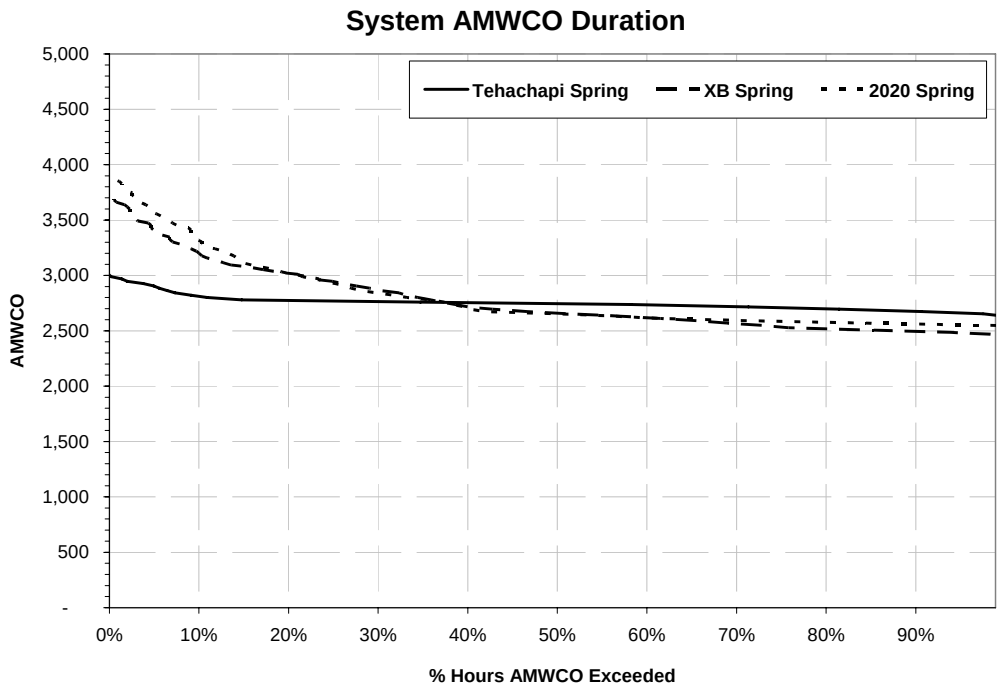


Figure 6-26: System AMWCO Duration Trend, Spring Peak

Table 6-12: System AMWCO Trend Statistics, Spring Peak

	2010T	2010XB	2020
Total No. of CTG Overloaded Elements	68	74	133
Hourly AMWCO Average	2,747	2,771	2,808
Hourly AMWCO Std. Deviation/Average	2.3%	10.7%	11.6%
Hourly AMWCO Std. Deviation/Load	0.14%	0.63%	0.58%
Hourly AMWCO Std. Deviation/Wind Production Std. Deviation	4.2%	12%	13%
Wind Production Average/Load	5.5%	9.0%	7.7%
Wind Production Std. Deviation/Load	3.2%	5.1%	4.4%
Hourly AMWCO Correlation with Regional Wind Production			
Altamont	(0.19)	0.71	0.74
Pacheco	0.02	0.67	0.59
San Gorgonio	0.52	0.72	0.49
Solano	(0.32)	0.75	0.77
Tehachapi	0.22	0.46	0.42

Table 6-12 illustrates statistics about contingency overloading for the spring peak scenarios. The total number of transmission elements that are overloaded at least once during the simulation is almost constant in 2010 Tehachapi and 2010 XB, but increases sharply in 2020. However, variability of the hourly System AMWCO, as measured by the standard deviation as a

percentage of the average, increases sharply with 2010 XB, then remains relatively constant from 2010 XB to 2020. This again suggests that the increase in penetration of renewable resources has an adverse effect on contingent transmission loading variability in 2010 XB, though the locational value of such resources softens the impact on average loading.

The contingent transmission loading variation in the spring peak scenarios is considerably greater than that of the summer peak scenarios, especially in 2010 XB and 2020. Energy supplied by intermittent resources and the variability of that energy, as a share of the total load, are considerably greater in the spring peak than in the summer peak. The spring peak reveals a sharp increase in System AMWCO variability with respect to load in 2010 XB. The System AMWCO variability with respect to wind production variability increases with each successive scenario, even as wind production decreases slightly as a share of load in 2020. The challenges posed by intermittency are not expected to be alleviated with the increased capacity of intermittent resources.

The fact that hourly System AMWCO is strongly correlated with most regions wind production in 2010 XB and 2020 is also of interest. This suggests that the increases in System AMWhCO are driven by increasing wind capacity as well as load.

2010 Tehachapi Scenario

The total System AMWhCO for the 2010 Tehachapi scenario is 923,000 MWh, with an average System AMWCO of 2,747 MW. These figures reveal the lighter loading experienced in the spring case, relative to the summer case. The System AMWCO duration curve is shown in Figure 6-27.

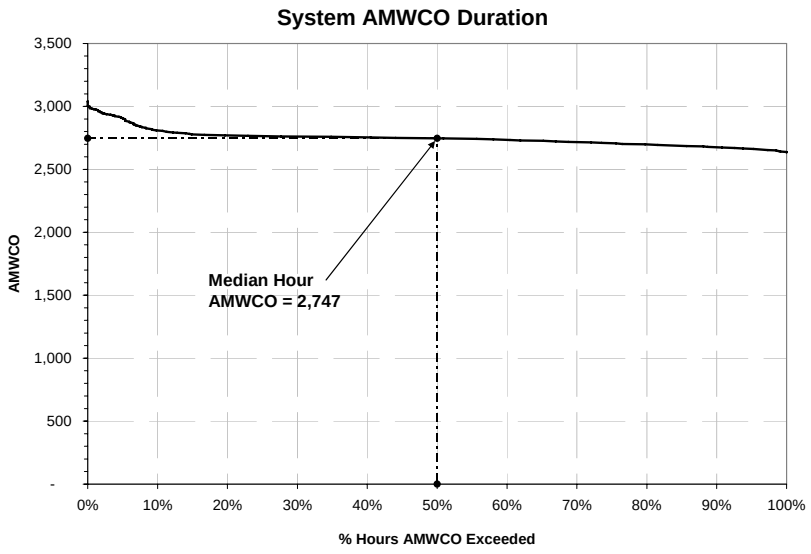


Figure 6-27: System AMWCO Duration, 2010 Tehachapi Spring Peak

There are 68 transmission elements that overload at least once during the hourly contingency simulation and contribute to the System AMWhCO. Of the 68 transmission elements, 12 produce at least 25,000 AMWhCO and together account for 72% of the total. Most contingent

transmission overloads are correlated with Tehachapi and San Gorgonio production, while others tend to overload at constant levels regardless of wind production. Details are presented in Table 6-13.

Table 6-13: Major AMWhCO Contributions, 2010 Tehachapi Spring Peak

"From Bus" Num.	"From Bus" Name	"To Bus" Num.	"To Bus" Name	Ckt	Xfr	kV	AMWh-CO	% of Total	Std. Dev./ Avg.	Corr.
30018	ROUTAB21	30019	ROUTAB22	2	No	500	117,432	12.7%	2.9%	SG+
30016	ROUTAB11	30017	ROUTAB12	1	No	500	115,891	12.6%	2.9%	SG+
40687	MALIN	40692	MALROU21	2	No	500	74,996	8.1%	7.5%	SG,T+
30041	TABTES11	30043	TABTES12	1	No	500	69,616	7.5%	4.6%	A,P,S,T-
30526	PITSBG D	30528	DEC PTSG	1	No	230	53,348	5.8%	0.2%	SG,T+
30526	PITSBG D	30528	DEC PTSG	2	No	230	53,348	5.8%	0.2%	SG,T+
40692	MALROU21	40694	MALROU22	2	No	500	37,801	4.1%	14.8%	SG,T+
21045	MIDWAY X	21046	MIDWAY X	1	Yes	230	31,458	3.4%	0.0%	
21045	MIDWAY X	21046	MIDWAY X	2	Yes	230	31,458	3.4%	0.0%	
25001	GOODRICH	25002	GOODRICH	3	Yes	230	29,105	3.2%	0.0%	
25001	GOODRICH	25002	GOODRICH	2	Yes	230	27,700	3.0%	0.0%	
25001	GOODRICH	25002	GOODRICH	1	Yes	230	26,319	2.9%	0.0%	
	Subtotal						668,472	72.4%		

Notable for high variability and correlation to southern California wind production are the Malin – Round Mountain 500 kV circuits. Heavy production in the south partially loops through the system to the east, slightly increasing COI loading. On the other hand, heavy production in the north may provide more direct relief to the COI. The COI is also vulnerable to contingency overloads in the summer case, but the amount of the overload is not strongly related to wind variation. The contingency overloading on the Table Mountain – Tesla 500 kV circuit is also significant, and is inversely related to production in most regions. It should be noted that each of these elements experience some contingency overloading, regardless of wind output.

2010 XB Scenario

The spring peak case reveals higher variability on most transmission line loadings in the 2010 XB scenario than the 2010 Tehachapi scenario, which is similar to the summer peak case results.

The total simulated System AMWhCO for the spring peak case is 931,000 MWh, with an average System AMWCO of 2,771 MW. These figures reflect approximately identical average reliability to the 2010 Tehachapi simulation though hourly variability increases, owing primarily to increase variable wind production. The System AMWCO duration curve is shown in Figure 6-28.

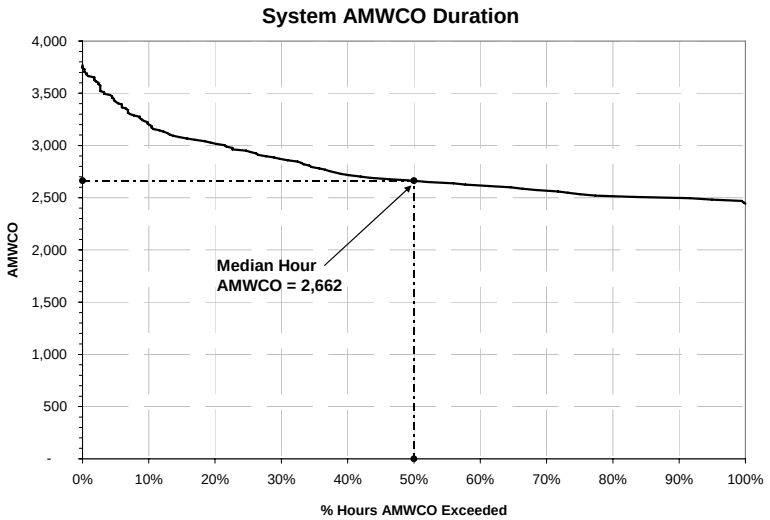


Figure 6-28: System AMWCO Duration, 2010 XB Spring Peak

In the 2010 XB case, there are 74 transmission elements that overload at least once during the hourly contingency simulation and contribute to the System AMWhCO. Of the 74 transmission elements, 11 produce at least 25,000 AMWhCO and together account for 75% of the total. Several contingent transmission overloads are correlated with various regions wind production, while others tend to overload at constant levels regardless of wind production. Details are presented in Table 6-14.

Table 6-14: Major AMWhCO Contributions, 2010 XB Spring Peak

"From Bus" Num.	"From Bus" Name	"To Bus" Num.	"To Bus" Name	Ckt	Xfr	kV	AMWh-CO	% of Total	Std. Dev./ Avg.	Corr.
30041	TABTES11	30043	TABTES12	1	No	500	108012	11.6%	18.8%	A,S+
30018	ROUTAB21	30019	ROUTAB22	2	No	500	100523	10.8%	8.5%	
30016	ROUTAB11	30017	ROUTAB12	1	No	500	99035	10.6%	8.6%	
21007	COACHELV	24804	DEVERS	1	No	230	93782	10.1%	8.8%	P,SG,T-
21076	RAMON	24806	MIRAGE	1	No	230	61621	6.6%	10.0%	P,SG,T-
21076	RAMON	21007	COACHELV	1	No	230	60321	6.5%	6.7%	P,SG,T-
40687	MALIN	40692	MALROU21	2	No	500	57508	6.2%	20.8%	
30460	VACA-DIX	30472	PEABODY	1	No	230	34650	3.7%	146%	A,S+
21045	MIDWAY X	21046	MIDWAY X	1	Yes	230	27838	3.0%	0.0%	
21045	MIDWAY X	21046	MIDWAY X	2	Yes	230	27838	3.0%	0.0%	
24128	S.CLARA	24127	S.CLARA	4	Yes	230	25831	2.8%	9.6%	P,SG,T+
Subtotal							696,959	74.9%		

Several elements exhibit high variability and correlation to one or more region's wind production. The Table Mountain – Tesla 500 kV circuit and the Vaca Dixon – Peabody 230 kV circuit are correlated with high production at Altamont and Solano, as they are in the summer 2010 XB scenario. The Ramon – Mirage 230 kV circuit in the south exhibits highest overloading when wind production at Tehachapi and San Gorgonio are light.

The 2010 XB spring peak hourly System AMWCO exhibits approximately the same average as the 2010 Tehachapi spring peak, but the standard deviation is much higher, owing to the substantial increase in installed wind capacity. Furthermore, the hourly System AMWCO is positively correlated with wind production at Altamont, Solano, and San Gorgonio. High wind production in these areas causes an overall increase in contingency overloading.

2020 Scenario

System AMWhCO for the 2020 spring peak case is 943,000 MWh, with an average System AMWCO of 2,808 MW. These figures show a slight increase from the 2010 Tehachapi and 2010 XB simulations, owing to increased load and increased impacts from intermittent resources. The System AMWCO duration curve is shown in Figure 6-29.

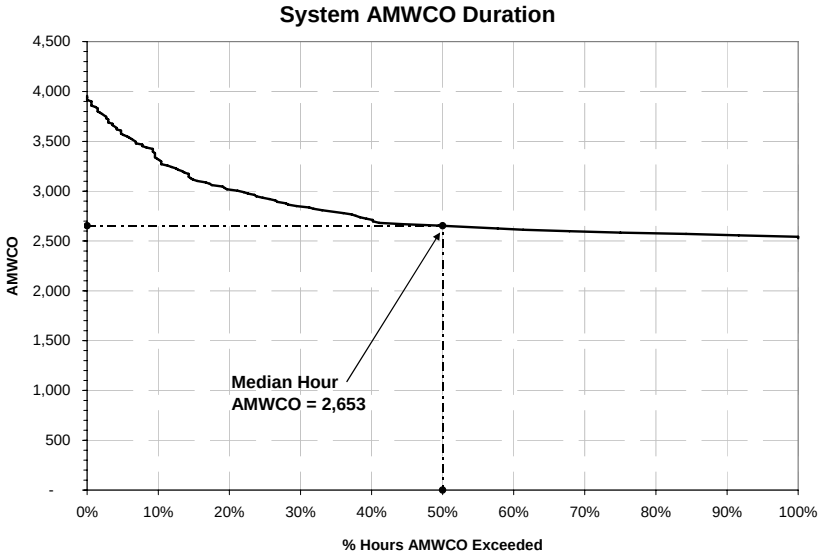


Figure 6-29: System AMWCO Duration, 2020 Spring Peak

For the 2020 case, there are 133 transmission elements that overload at least once during the hourly contingency simulation and contribute to the System AMWhCO. This represents a sharp increase from the 2010 XB scenario and reflects a diffusion of the overloading across the system. Of the 133 transmission elements, 22 elements produce at least 14,000 AMWhCO and together account for 61% of the total. Most of these major contingent transmission overloads are correlated with one or more region's wind production. Details are presented in Table 6-15.

Table 6-15: Major AMWhCO Contributions, 2020 Spring Peak

"From Bus" Num.	"From Bus" Name	"To Bus" Num.	"To Bus" Name	Ckt	Xfr	kV	AMWh-CO	% of Total	Std. Dev./ Avg.	Corr.
37013	ORANGEVL	37018	WHITEROK	1	No	230	58,286	6.2%	16.0%	P,SG,T-
37018	WHITEROK	37028	CORDOVA	1	No	230	44,357	4.7%	20.2%	P,SG,T-
24910	CAL ELEC	24912	SHANDIN	1	No	115	41,035	4.3%	0.3%	P,SG,T+
24065	HINSON	24064	HINSON	1	Yes	230	40,468	4.3%	0.0%	
24065	HINSON	24064	HINSON	4	Yes	230	40,468	4.3%	0.0%	
37001	CAMINO S	37012	LAKE	1	No	230	37,607	4.0%	26.5%	P,SG,T-
30460	VACA-DIX	30472	PEABODY	1	No	230	34,198	3.6%	146.7%	A,S+
38460	CERES	38462	TUOLUMNE	1	No	69	31,742	3.4%	11.0%	A,P,SG,T+
21046	MIDWAY X	21043	LEATHERS	2	No	92	26,177	2.8%	0.3%	SG+
30430	FULTON	30435	LAKEVILE	1	No	230	22,047	2.3%	3.3%	SG,T+
34321	MCSWAINJ	34232	EXCHEQUR	1	No	70	19,096	2.0%	0.1%	A,P,S+
21064	ROCKWOOD	21980	BRAWLEY	1	No	92	18,715	2.0%	23.1%	P,SG,T+
38462	TUOLUMNE	38470	HUGHSON	1	No	69	18,617	2.0%	10.4%	A,P,SG,T+
33020	MORAGA	32792	STATIN J	1	No	115	17,467	1.9%	0.5%	A,S+
34321	MCSWAINJ	34230	MRCDFLLS	1	No	70	17,314	1.8%	0.1%	A,P,S+
34202	MERCED	34230	MRCDFLLS	1	No	70	16,418	1.7%	0.2%	A,P,S+
24910	CAL ELEC	24904	HIGROVE	2	No	115	15,870	1.7%	1.6%	SG,T+
21005	COACHELA	21008	COACHELV	1	No	92	15,263	1.6%	9.9%	P,SG,T+
21005	COACHELA	21008	COACHELV	2	No	92	15,263	1.6%	9.9%	P,SG,T+
35918	SALINAS2	35928	DOLAN J2	1	No	115	15,179	1.6%	4.6%	A,P,SG,T+
36051	SPNCE J1	36053	SPENCE	1	No	60	14,559	1.5%	0.2%	A,P,SG,S,T+
26088	OLYMPCLD	26127	OLYTAR11	1	No	138	14,293	1.5%	28.4%	P,SG,T+
Subtotal							574,439	60.9%		

Several lines exhibit high variability and correlation with Pacheco, San Gorgonio, and Tehachapi production, though the sign of the correlation varies. The Orangeville – White Rock, White – Rock Cordova, and Camino – Lake 230 kV circuits all reveal negative correlation with these regions' wind production, which is likely due to the proximity of SMUD's Iowa Hill generator, which follows wind variation with other units across the system. A remedial action scheme which varies output of this unit when nearby lines are taken out of service may likely reduce the overloading.

Conversely, the Tuolumne – Hughson 69 kV line correlates positively with several regions' wind production, due to the proximity of a wind following unit. A remedial action scheme may be beneficial to keep a load pocket from developing on the low voltage network. Several lines in the south also exhibit high variability and positive correlation with San Gorgonio, Tehachapi, and Pacheco wind production.

The Vaca Dixon – Peabody 230 kV circuit is highly variable and positively correlates with Altamont and Solano production, as seen in the 2010 XB simulation. Upgrading of the line may be desirable to support high production in these regions.

Notable for high variability and correlation to southern California wind production are the Malin – Round Mountain 500 kV circuits. Heavy production in the south partially loops through the system to the east, slightly increasing COI loading. On the other hand, heavy production in the north may provide more direct relief to the COI. The COI is also vulnerable to contingency overloads in the summer case, but the amount of the overload is not strongly related to wind variation. Contingency overloads on the Table Mountain – Tesla 500 kV circuit are also significant, and are inversely related to production in most regions. It should be noted that each of these elements experiences some contingency overloading, regardless of wind output.

Fall Off-Peak

The behavior and characteristics of the fall off-peak simulation are distinctly different from those of the summer and spring peaks. Figure 6-30 shows transmission branch AMWhCO contour maps of each successive scenario. The system load in the fall off-peak period is extremely light, while wind production can be higher than in other seasons. The highest simulated Tehachapi capacity factor is observed in the fall off-peak simulation. The combination of high wind and light load leads to a much higher percentage of load being served by intermittent and variable resources.

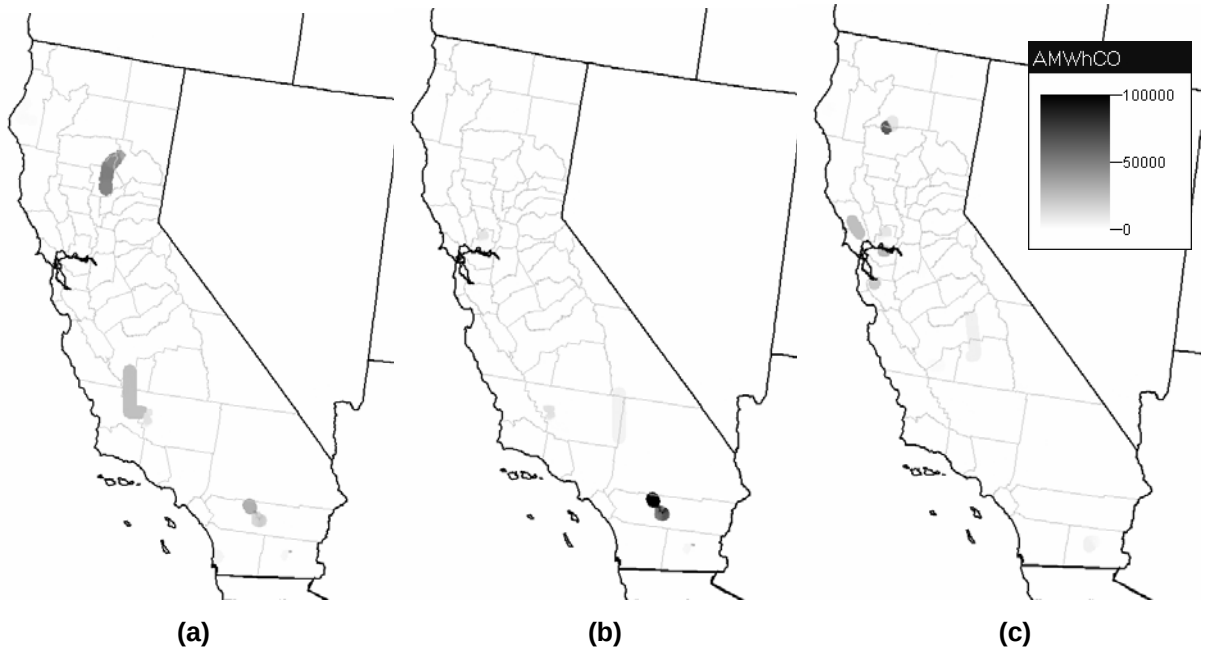


Figure 6-30: AMWhCO Contours, Fall Off-Peak: (a) 2010 Tehachapi, (b): 2010 XB, (c) 2020

Figure 6-31 shows the trend in System AMWCO duration curves for the fall scenarios.

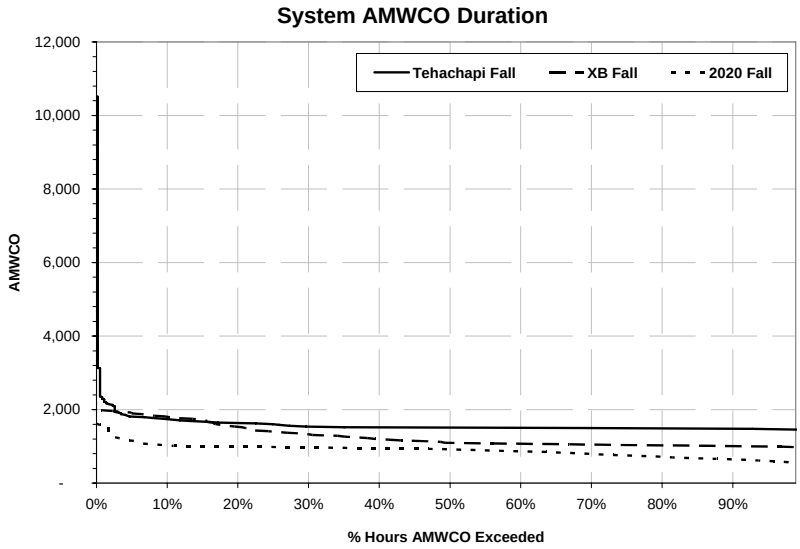


Figure 6-31: System AMWCO Duration Trend, Fall Off-Peak

Table 6-16: System AMWCO Trend Statistics, Fall Off-Peak

	2010T	2010XB	2020
Total No. of CTG Overloaded Elements	32	22	30
Hourly AMWCO Average	1,594	1,261	886
Hourly AMWCO Std. Deviation/Average	32%	24%	20%
Hourly AMWCO Std. Deviation/Load	1.9%	1.1%	0.57%
Hourly AMWCO Std. Deviation/Wind Production Std. Deviation	46%	17%	10%
Wind Production Average/Load	4.8%	7.7%	6.6%
Wind Production Std. Deviation/Load	4.2%	6.5%	5.6%
Hourly AMWCO Correlation with Regional Wind Production			
Altamont	(0.06)	0.07	0.49
Pacheco	(0.02)	0.01	0.31
San Gorgonio	0.24	(0.45)	(0.45)
Solano	(0.03)	0.00	0.54
Tehachapi	0.43	(0.47)	(0.64)

Table 6-16 illustrates statistics about contingency overloading for the fall off-peak scenarios. The fall off-peak scenarios are distinct from the other two seasons in that the contingency overloading and variability generally improves with each successive scenario. The 2010 Tehachapi scenario is skewed by a few hours of unusually heavy Tehachapi production that overloads the planned 500 kV Tehachapi upgrade, as will be discussed in detail in subsequent sections. From 2010 XB to 2020, the absolute level and variability of contingency overloading generally improves by most measures reported in the table, contrary to the trends observed in

the summer and spring peaks. In absolute terms, the system appears better able to absorb variation from intermittent production during periods of light load.

2010 Tehachapi Scenario

From the hourly contingency simulation, the total System AMWhCO for the Tehachapi scenario is 535,539 MWh, with an average System AMWCO of 1,594 MW. The System AMWCO duration curve is shown in Figure 6-32.

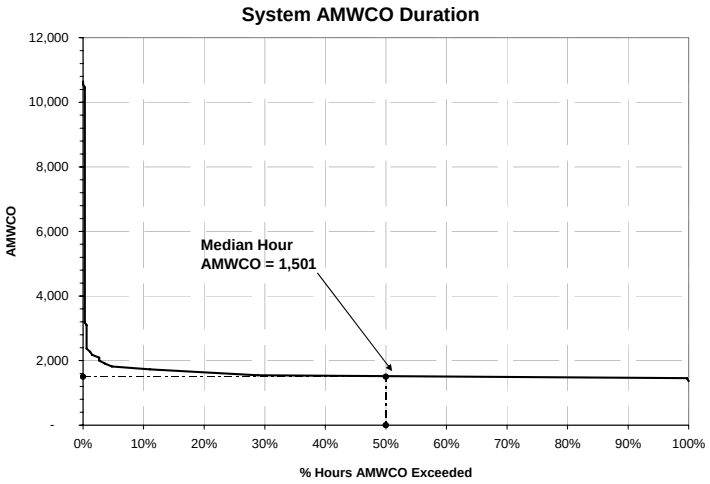


Figure 6-32: System AMWCO Duration, 2010 Tehachapi Fall Off-Peak

A few hours of extremely high hourly System AMWCO occur during a period of unusually high Tehachapi production, which coincides with low wind production in northern California. The proposed Tehachapi – Midway 500 kV circuit is overloaded under contingencies, as in the base case. The line includes a modeled capacity of 1,848 MVA, limited by one of its series capacitors. The capacitor rating may be inadequate to support some wind patterns, unless conventional resources in Northern California are dispatched to sufficiently offset south to north flows or unless the capacitors are bypassed during heavy loading. The contingency rating of the proposed transmission line itself is 2,567 MVA.

In the 2010 Tehachapi case, there are 32 transmission elements that overload at least once during the hourly contingency simulation and contribute to the System AMWhCO. Of the 32 transmission elements, eleven produce at least 24,000 AMWhCO and together account for 84% of the total. Several contingent transmission overloads are correlated with Tehachapi or San Gorgonio production, while others tend to overload at constant levels regardless of wind production. Details are presented in Table 6-17.

Table 6-17: Major AMWhCO Contributions, 2010 Tehachapi Fall Off-Peak

"From Bus" Num.	"From Bus" Name	"To Bus" Num.	"To Bus" Name	Ckt	Xfr	kV	AMWh-CO	% of Total	Std. Dev./ Avg.	Corr.
30526	PITSBG D	30528	DEC PTSG	1	No	230	56877	10.6%	0.2%	T+
30526	PITSBG D	30528	DEC PTSG	2	No	230	56877	10.6%	0.2%	T+
31516	WYANDJT2	31512	BIG BEND	2	No	115	50375	9.4%	0.1%	T+
31482	PALERMO	31516	WYANDJT2	2	No	115	47687	8.9%	0.1%	T+
31488	GRIZ JCT	31512	BIG BEND	1	No	115	45537	8.5%	0.1%	T+
21076	RAMON	24806	MIRAGE	1	No	230	42693	8.0%	**10.8%**	**SG-**
31486	CARIBOU	31488	GRIZ JCT	1	No	115	33824	6.3%	0.1%	T+
21007	COACHELV	24804	DEVERS	1	No	230	30975	5.8%	**13.0%**	**SG-**
21045	MIDWAY X	21046	MIDWAY X	1	Yes	230	30301	5.7%	0.0%	
21045	MIDWAY X	21046	MIDWAY X	2	Yes	230	30301	5.7%	0.0%	
30075	GATMID11	30060	MIDWAY	1	No	500	24484	4.6%	**183.2%**	**T+**
Subtotal							449,931	84.0%		

In addition to the Tehachapi – Midway 500 kV circuit, contingency overloads on the Gates – Midway 500 kV circuit are also highly variable and positively correlates to Tehachapi wind production. The Ramon – Mirage and Coachella – Devers 230 kV circuits are inversely correlated to San Gorgonio production.

The 2010 Tehachapi cases reveal significant reliability improvements over the 2006 summer peak case. The 2010 Tehachapi transmission upgrades when combined with SVA renewable resource deployment in favorable locations results in a greater capacity to absorb variable wind resources. However, periods of high Tehachapi wind production, especially when coincident with low Altamont and Solano production, still cause notable reliability problems. Improving the rating of the proposed Tehachapi – Midway 500 kV path, coupled with coordinated re-dispatch of conventional resources to replace lost power in the north may improve security.

2010 XB Scenario

The total simulated System AMWhCO for the fall off-peak case is 424,000 MWh, with an average System AMWCO of 1,261 MW. These figures reflect improvements in both average reliability and hourly variability relative to the 2010 Tehachapi simulation, which is affected by a few hours of extremely high System AMWCO. The System AMWCO duration curve is shown in Figure 6-33.

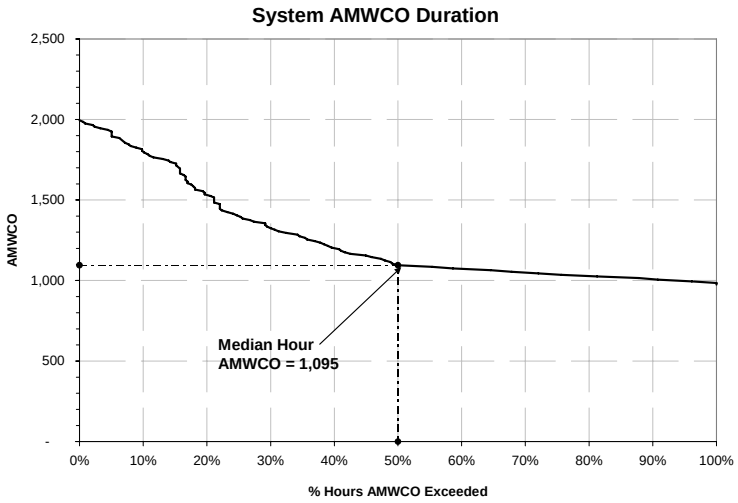


Figure 6-33: System AMWCO Duration, 2010 XB Fall Off-Peak

In the 2010 XB case, there are 22 transmission elements that overload at least once during the hourly contingency simulation and contribute to the System AMWhCO. Of these 22 transmission elements, eight produce at least 10,000 AMWhCO and together account for 95% of the total. Several contingent transmission overloads are correlated with Tehachapi or San Gorgonio wind production, while others tend to overload at constant levels regardless of wind production. Details are presented in Table 6-18.

Table 6-18: Major AMWhCO Contributions, 2010 XB Fall Off-Peak

"From Bus" Num.	"From Bus" Name	"To Bus" Num.	"To Bus" Name	Ckt	Xfr	kV	AMWh-CO	% of Total	Std. Dev./ Avg.	Corr.
21076	RAMON	24806	MIRAGE	1	No	230	149,402	35.2%	66.3%	
21007	COACHELV	24804	DEVERS	1	No	230	106,414	25.1%	4.7%	SG,T-
21076	RAMON	21007	COACHELV	1	No	230	51,162	12.1%	4.6%	SG,T-
21045	MIDWAY X	21046	MIDWAY X	1	Yes	230	30,290	7.1%	0.0%	
21045	MIDWAY X	21046	MIDWAY X	2	Yes	230	30,290	7.1%	0.0%	
38605	BUENAVJ2	30970	MIDWAY	1	No	230	11,550	2.7%	5.8%	SG,T+
38600	BUENAVJ1	30970	MIDWAY	1	No	230	11,507	2.7%	5.9%	SG,T+
30460	VACA-DIX	30472	PEABODY	1	No	230	10,124	2.4%	**311%**	**A,S+**
Subtotal							400,739	94.5%		

The Ramon – Mirage 230 kV circuit is heavily congested and highly variable, though no single regions wind production is strongly correlated with the level of contingency overloading. The Vaca Dixon – Peabody 230 kV circuit is again heavily congested, with overloads highly positively correlated with Altamont and Solano wind production. This observation also occurs for the summer peak and spring peak 2010 XB scenarios. Most other congestion occurs at relatively constant levels.

2020 Scenario

System AMWhCO for the 2020 fall off-peak case is 298,000 MWh, with an average System AMWCO of 886 MW. These figures reflect improvements in both average reliability and hourly variability over the 2010 Tehachapi and 2010 XB simulations. The System AMWCO duration curve is shown in Figure 6-34.

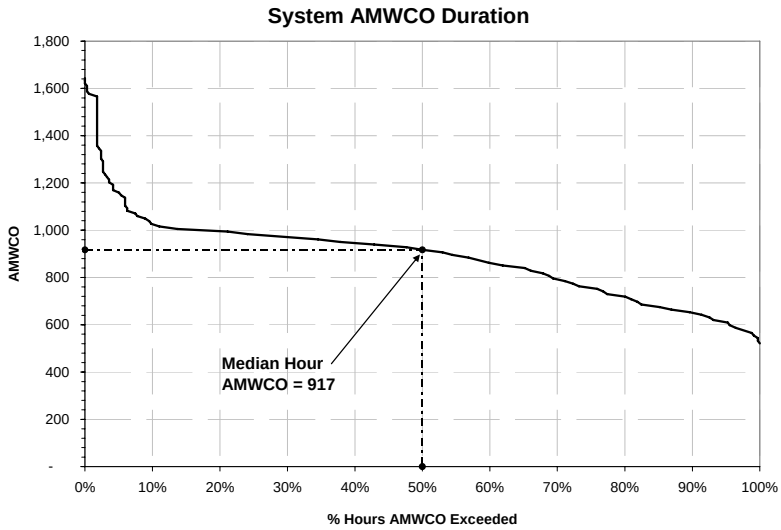


Figure 6-34: System AMWCO Duration, 2020 Fall Off- Peak

System AMWCO is not strongly correlated with any regional wind production, though the hours of highest congestion coincided with peak seasonal Solano production. As with the 2010 XB simulation, the Tehachapi – Midway series capacitors are modeled with upgrades which reduce contingency overloads on that circuit.

In the 2020 case, there are 30 transmission elements that overload at least once during the hourly contingency simulation and contribute to the System AMWhCO. Of the 30 transmission elements, twelve produce at least 9,000 AMWhCO and together account for 91% of the total. Most contingent transmission overloads are either correlated with Tehachapi and San Gorgonio wind production or with Altamont and Solano wind production. Details are presented in Table 6-19.

The elements with inverse correlations with Tehachapi and San Gorgonio production are driven primarily by the wind following response of natural gas-fired resources. Strengthening of many such paths is desirable to support system expansion into 2020. The Vaca Dixon – Peabody 230 kV circuit is again observed to exhibit strong positive correlation with Altamont and Solano production and may require upgrading if it cannot be relieved operationally.

Table 6-19: Major AMWhCO Contributions, 2020 Fall Off-Peak

"From Bus" Num.	"From Bus" Name	"To Bus" Num.	"To Bus" Name	Ckt	Xfr	kV	AMWh-CO	% of Total	Std. Dev./ Avg.	Corr.
37565	OLINDAW	30020	OLINDA	1	Yes	500	64,561	21.7%	41.7%	T-
30526	PITSBG D	30528	DEC PTSG	1	No	230	26,640	9.0%	50.1%	SG,T-
30526	PITSBG D	30528	DEC PTSG	2	No	230	26,640	9.0%	50.1%	SG,T-
30430	FULTON	30435	LAKEVILE	1	No	230	24,777	8.3%	1.7%	SG,T+
36850	KIFER	36885	KIFERINB	KB	Yes	115	20,447	6.9%	13.2%	SG,T+
36878	KIFER_60	36885	KIFERINB	KB	Yes	60	20,447	6.9%	13.2%	SG,T+
36851	NRS115_1	36899	NRSINTBA	NA	Yes	115	19,016	6.4%	6.7%	A,S+
36892	NRTHRN60	36899	NRSINTBA	NA	Yes	60	19,016	6.4%	6.7%	A,S+
36853	NRS115_2	36896	NRSINTBB	NB	Yes	115	15,106	5.1%	8.3%	A,S+
36892	NRTHRN60	36896	NRSINTBB	NB	Yes	60	15,106	5.1%	8.3%	A,S+
30460	VACA-DIX	30472	PEABODY	1	No	230	9,894	3.3%	**314.8%**	**A,S+**
37544	AIRPORTW	37545	COTWDWAP	1	No	230	9,551	3.2%	22.7%	SG,T-
Subtotal							271,201	91.1%		

7.0 Conclusions and Future Analysis

7.1. Conclusions

The IAP transmission team concludes the following:

- The WECC power flow data sets are not consistent between years and seasons. Extensive corrective measures are required to make the cases useful for the IAP project.
- The results of the IAP are limited due to the availability of wind data.
- If the necessary system enhancements are made, California utilities may meet the 20% penetration target in 2010 with in-state renewable resources.
- If the necessary system enhancements are made, California utilities may meet the 33% penetration target in 2020 with in-state renewable resources.
- Steady state voltage stability is a concern as generation resources are added to the California system.
- Intermittency analysis indicates that wind variability contributes to transmission congestion under certain renewable dispatch scenarios, and that transmission congestion patterns are more difficult to predict as the penetration of intermittent resources increases.

7.1.1. Data Set Compatibility

The WECC data sets are the desired data sets for the IAP since these have a complete modeling of the California system and inter-area interchanges for the seasons and time frames studied. However, it is found that the WECC solved power flow data sets are not consistent among years and seasons. There are numerous bus numbering, bus naming, transmission topology and bus loading problems among the data sets. This requires an extensive effort to resolve the differences across the three studied seasons, so that the results of each season can be compared. Once the network configurations of the three seasonal cases are topologically identical, the seasonal cases are expanded out to the future year loadings and renewable penetrations using the same topology as a basis for all seasons and years.

In addition to the topological issues, the interchange assumptions in all WECC power flow data sets are preset to maximum imports and/or exports, which make re-dispatching of resources in the power flow model difficult. The import/export extremes are maintained in the data sets for the IAP study, but should be modified in future studies to an import/export schedule more representative of “normal” operating conditions. In the IAP study, the extreme imports/exports did force an extended set of non-reliability-must-run units to be used as generation offset for the renewable resources being added to the data sets.

The methodologies and models created in this transmission IAP study can be used to continue detailed analysis of transmission and resource expansion in California and the WECC region. The methodologies can be used to study demand-side resources, supply-side resources and intra- and inter-state transmission expansion.

7.1.2. Input Data Limitations

The results of the IAP study are restricted due to the limitation of data. The effects of intermittency from CSP and PV renewables are not included in the transmission intermittency analysis due to lack of hourly intermittent data. Therefore the intermittency results are due solely to the effects of wind variation. Forecasted data used by GE Consulting in their study of 147 wind sites was not available for the DPC transmission study. Instead, DPC acquired hourly historical wind data from the CAISO, which is separated into five wind regions. The regional wind data is used to create wind patterns for new wind sites by grouping each new site into one of the five regions. The capacity factor patterns of the five wind regions are a good preliminary analysis criterion to test the methodology and obtain a general understanding of the effect of intermittency on the transmission system. Ideally the analysis may yield more accurate intermittency results if the forecasted wind patterns of each individual wind site are implemented, if advances in turbine technology are incorporated and if load is allowed to vary. For these reasons, the analysis is viewed as preliminary and more as verification of a methodology for testing the potential impacts of intermittent resources on the transmission system.

7.1.3. 2010 Renewable Resource Target

The results of the 2010 case developed for the IAP study indicate that California utilities can meet the 20% penetration target in 2010 with in-state renewables. However, the target can only be met if permitting, licensing and construction of transmission infrastructure can be completed by 2010. Also, the in-state target can only be met if the available resources are the least-cost, best-fit alternatives when compared to out-of-state resources. To reiterate, only in-state renewable resources are considered for the IAP project.

The 2010 renewable mix target relies on Tehachapi wind resources at 3,000 MW, San Gorgonio development of 1,412 MW, and extensive development of geothermal and CSP renewable resources. This mix of renewable resource generation requires infrastructure improvements which include 74 new or upgraded transmission line segments (i.e. section of a line between two substations) ranging from 69 kV to 500 kV. Most of the 500 kV upgrades are associated with the Tehachapi wind generation development. A majority of the upgrades (63) are lower voltage improvements to move power to the growing load. An estimated cost for just the 500 kV and 230 kV transmission lines and tower upgrades or additions is approximately $1.2 billion.

In addition to the transmission line upgrades, several transformer upgrades are also identified for the 2010 case development. A total of 31 transformers are added or improved, most of which are upgrades to transformers in lower voltage substations. An estimated cost for the transformer upgrades is $161 million.

7.1.4. 2020 Renewable Resource Target

The 2020 renewable energy target can also be met with in-state renewable resources, but requires even more extensive transmission upgrading. Line upgrades are needed to meet load growth and new power plant construction. Many of the line upgrades developed in this IAP study are already being planned and budgeted by the utilities. Again, the target can only be met if permitting, licensing and construction of transmission infrastructure can be completed by

2020. Also, the target can only be met if the available resources are the least-cost, best-fit alternatives when compared to out-of-state resources.

The 2020 renewable mix target relies on Tehachapi wind resources at 4,500 MW, San Gorgonio development of 1,412 MW, Salton Sea geothermal at 1,400 MW, Solano wind at 1,085 MW, residential PV at 2,860 MW and extensive development of geothermal, wind and CSP renewables in other regions. This mix of renewable resource generation requires infrastructure improvements of 128 new or upgraded transmission line (i.e. section of a line between two substations) ranging from 69 kV to 500 kV. Most of the 500 kV upgrades are associated with the Tehachapi wind development, the SDG&E Sun Path expansion project, and a fourth COI line (with supporting area upgrades). A majority of the upgrades (66) are lower voltage improvements to move power to the growing load. An estimated cost for just the 500 kV and 230 kV transmission line and tower upgrades or additions is approximately $5.7 billion.

In addition to the transmission line upgrades, several transformer upgrades are also identified for the 2020 case development. A total of 40 transformers are added or improved, most of which are upgrades in higher voltage substations. An estimated cost for the transformer upgrades is $655 million.

7.1.5. Voltage Stability Concerns

Steady state voltage stability is a concern in the development of the study cases for the IAP analysis. Initially the WECC base case data sets show a small number of locations in the network with marginally low or high voltages. These voltages do not prevent base case load solution, but are noted. However, once load growth and renewable resource additions are added for the 2010 and 2020 scenarios, the steady state voltages demonstrate significant problems, resulting in solution failure/voltage collapse. A significant amount of VAR compensation (1,860 MVAR total) is required to provide for stable voltage solutions in the 2020 intermittency analysis scenarios. The locations for the added VAR support are approximated using PV/QV techniques on the 2020 model as renewable resources are gradually added to the system. Ultimately the need for VAR support may vary as the initial power flow data sets are analyzed for proper VAR flow and adequate compensation first (to correct marginal base case voltages) and then planning studies evaluate those base cases as load and generation growth are modeled out to future years.

7.1.6. Intermittency Analysis Results

Intermittent resources create a more complex analysis for transmission planning. The duration of the overloads created by intermittent resources requires transmission planners to consider line upgrades, RAS, re-dispatching, load and generator shedding, and other alternatives. A solution may not always be line upgrading since the overload duration from intermittent resources may be short. More complex alternatives may be required to minimize transmission expenditures.

With the addition of thousands of megawatts of wind at Tehachapi, the transmission lines north of Midway require extensive analysis. The results indicate that the fall period may have more transmission problems when load is low, wind generation is high and exports from the

southwest to the northwest over the California 500 kV network are high. The results also indicate that problems occur when southern California wind is high and northern California wind is low.

The intermittency simulations reveal that overall security of the California transmission system, as measured by the hourly System AMWCO, generally is more variable as the penetration and production from intermittent resources grows through 2020. The Summer 2020 simulation also reflects how extreme load levels amplify vulnerabilities as the system is operated near its capacity. This may require additional operational flexibility to support a wide range of generation production patterns. Upgrading the transmission system beyond the level assumed in this study may also be desirable to increase its inherent robustness in support of variable and intermittent regional wind production patterns.

The simulations reveal specific areas in which the California transmission system may be vulnerable to the effects of variable production from wind resources. Some vulnerability may be addressed through operational practices such as remedial action schemes, coordinated dispatch of wind following resources, or wind curtailment, especially those on low voltage lines. However, several transmission elements exhibit overloading across scenarios, spanning the range of simulated system conditions. Such transmission issues are described in Table 7.1.

Table 7-1: Frequently Congested Transmission Elements

Transmission Element(s)	Notes
Altamont 70 kV collector network	May require upgrades to support planned capacity in the Altamont region
Ramon – Mirage 230 kV	Vulnerable during light San Gorgonio production
Folsom 230/115 kV transformer	Critical to support planned natural gas-fired expansion, which may be needed to supplement wind and follow variation
Vaca Dixon – Peabody 230 kV	Susceptible to contingency overloading during heavy Altamont and Solano production
COI and downstream 500 kV	Vulnerable during periods of high Northwest imports
Tehachapi – Midway 500 kV series capacitor	Upgrade may be desirable to support high levels of Tehachapi production, unless it can be bypassed as needed

Overall the transmission expansion modeled in the study cases is sufficient to maintain system security in the fall off-peak and spring peak conditions, but is not sufficient for the summer peak, as evidenced by the increase in average AMWCO observed in the summer peak during the intermittency analysis. The intermittency analysis indicates that wind variability contributes to transmission congestion under certain renewable dispatch scenarios, and that transmission

congestion patterns are more difficult to predict as the penetration of intermittent resources increases.

7.2. Lessons Learned

Throughout the course of the IAP project, the IAP transmission team encountered various issues that presented technical and analytical difficulties. Many of these issues are addressed during the course of the IAP analysis process, which in turn helps address these same issues in future studies.

- Although the transmission power flow data sets are approved and solved data sets, the consistency of the data is a problem. Any future study needs to allocate sufficient time to work with the utilities to improve the consistency of the power flow data. Possibly the Energy Commission could take a more active role in working with the WECC to obtain consistent data sets for future analysis. It may be more beneficial to work with the California utilities that submit power flow data to the WECC to improve consistency in the data sets.
- The issue of transmission and generator upgrades used in a power flow study needs to be addressed early in the study. There are perceived differences in assumptions used by the utilities and the state agencies concerning the transmission elements to be included. This also applies to the development of transmission line characteristics for different design configurations for different voltages and also the cost assumptions for system expansion. There is also a need for consistent line costing assumptions to account for permitting, right of way acquisition and environmental issues.
- A closer working relationship between utility staff, California ISO, the California Public Utilities Commission (CPUC) and Energy Commission staff is needed, especially regarding the simulation models used to validate and verify power flow models. Most power simulation models do not model conditions far enough forward in time to be useful for a study like the IAP.
- A closer working relationship is needed between the CPUC, the Energy Commission and CAISO staff and the consultants to ensure that consistency of assumptions.
- Early in any project, the issues of the confidentially of power flow data and renewable resource locations must be addressed and resolved. The report reviewers commented on the need for confidentially so that resource locations can be shared. However, the methodology to secure such information is not yet developed.
- Any future studies should include time synchronous wind, solar, and load time series data and the inclusion of the optimal power flow in the transmission power flow analysis. In this IAP study, only wind data varies over time with load held constant. Solar data is not available for this evaluation. In reality, there are several steps in this process. First is the time series analysis without intermittent resources to determine the power flow impacts of load variation. The step is repeated with intermittent varying but load is held constant. The third is the combination of the two. The results can be used to complete probability analysis and variability impacts over a time series of events.
- Resource adequacy studies focus on the intermittent resource variability in providing a firm capacity resource to meet load and ancillary services. It becomes an analysis of how

much energy is available to support firm capacity. Transmission planning may also change and become more of an energy resource analysis rather than a capacity resource planning. The need for time series analysis of transmission power flows may drive future studies.

7.3. Future Analysis and Potential Projects

The transmission IAP study and the preliminary results indicate that additional work needs to be considered. The areas of interest include:

- Updating this study to include forecasted hourly wind data to expand the intermittency transmission impacts, to include evaluation of correlation between intermittent resources and load, and to include forecasts of CSP and PV renewable dispatch.
- Expanding the study to include combinations of in-state and out-of-state renewables.
- Incorporating the IAP transmission methodology into regional and sub-regional studies.
- Expanding the IAP analysis to include the use of optimal power flow modeling and to incorporate locational marginal pricing, congestion zones, the California ISO's Market Redesign, and Technology Update, and other California ISO operational considerations.
- Exploring the interplay of wind forecasting and transmission congestion management.
- Expanding the study to investigate alternative renewable resource locations. Scenario analysis of the impacts that different renewable mixes and locations have on transmission expansion
- Exploring the inclusion of probability and risk assessment analysis into the transmission penetration studies
- Expanding the power analysis to include N-2 contingency scenarios.

7.3.1. Improved Input Data

The IAP analysis performed by DPC is based on the best available data, given time and confidentiality constraints. The DPC study and findings can be improved if additional input data is made available. DPC looks forward to working with the Energy Commission and California utilities to acquire this data and perform improved studies. The data and the benefits that are provided to the study findings are discussed in the following details.

- Originally the intermittency analysis is performed using historical California ISO wind data to determine capacity factors for each study hour, which are applied to the future case conditions modeled in the IAP project. These hourly data are broken down into only five different wind regions within California. Obtaining and using the forecasted wind data for the California wind sites improves the results of the intermittency analysis study. The hourly forecasted wind data provide much more detailed data specific to each wind site, allowing for individual hourly variation of each wind site instead of a group of wind sites within a region all following the same wind variation pattern. The individual hourly capacity factors of each wind site illustrate the variable nature of each wind resource relative to other wind resources, and may result in different contingent overload findings in the DPC intermittency analysis.
- The contingency analysis in the intermittency study is generally constructed as n-1 contingencies within California. While we may not want to ignore the n-1 contingency

results already determined as they may identify new contingencies of concern that are not currently considered an issue, an improvement may be to model the California specific contingencies typically used for planning studies by the California ISO and California utilities. This includes single element contingencies, multiple element contingencies, and contingencies with remedial action schemes (i.e. special protection schemes) defined. This focuses the results on the critical contingencies already identified within California.

- The monitored elements in the intermittency analysis thus far are limited to individual branch (transmission line, transformer, series capacitor, etc.) elements. An improvement is to obtain and define the California transmission paths as well. The ratings defined for each path typically reflect the normal (non-contingent) operating limit. If the path rating is violated under normal system operation, the implication is that if a certain contingency or contingencies occur, system problems of some sort (thermal violation, voltage violation, etc.) occur. Repeating the intermittency analysis using the path definitions as the monitored elements provides insight into system security from the standpoint of California accepted path ratings. A comparison can be drawn to identify whether individual element monitoring or California defined path monitoring exhibit greater system security concerns.
- Another factor that can alter the findings of this analysis is a change in the locations of the renewable resources serving California, or the consideration of out-of-state renewable resources. Various additional studies using the same process developed in the IAP project can be performed to analyze the affects on the California transmission grid if varying percentages of renewable resources are assumed to be purchased from outside of California, or if renewable energy facilities are more geographically concentrated in California. In addition, more detailed information on planned renewable resource projects can help refine the capacity and grid penetration locations of in-state (and possibly out-of-state) renewables. This information allows for repeating the analysis and comparing the system security and congestion issues as more exact renewable locations are revealed.

7.3.2. Additional Analysis Possibilities

During the course of the IAP project, the DPC and Energy Commission team identified additional analyses originally outside the scope of the IAP project that may add value to the intermittency analysis or be of value on a stand-alone basis.

- During the intermittency analysis, a question is raised about ways to identify the level of renewable penetration that can be achieved for a given modeled year, without significant transmission upgrades. In theory, an analysis of this nature determines if expected penetration levels can be met with limited transmission investment, and if they are not met, where to look in the transmission system to perform upgrades to help achieve the desired penetration levels. The DPC team has two possible analyses to accomplish this identification.
    a. The first is the performance of an Available Transfer Capability (ATC) study on a system model, with the renewable resources in place and ready to be dispatched. The analysis is completed using the linear approximation ATC to estimate the shift of California generation from natural gas resources to renewable resources before a transmission element becomes limiting. The renewable resources are added to the system concurrently and in an amount proportional to the total MW capacity of each

renewable generation unit. Likewise, natural gas units in California decrease their output concurrently proportional to their maximum megawatt capability. The ATC analysis identifies several levels of MW shifted from the natural gas units to the renewable resource units, and which transmission elements are the limiting factors at each level. The downside to this type of transfer analysis study as described in this context is that the concurrent and proportional increase and decrease of generation resources is not typical of generation re-dispatch. Therefore the ATC method for this type of analysis potentially underestimates the amount of achievable renewable penetration before hitting transmission limitations.

b. A second method of identifying renewable penetration without significant transmission upgrades makes use of an *optimal power flow* (OPF) routine. In this method, the renewable resources are added and set at their maximum output capacity, offset by decreasing outputs of the natural gas units. This most likely will create overloads on transmission elements in the California system. The OPF can then be run, allowing for re-dispatch of natural gas and renewable generation, to alleviate the transmission overloads. The advantage of this method is twofold. First, the analysis optimizes the generation dispatch to alleviate the constraints, which results in a higher penetration level of renewables than the ATC method. Second, the OPF results identify the critical transmission constraints for that level of renewable penetration, which can be useful in locating transmission elements around which more detailed planning studies can be centered for possible expansion and/or mitigation techniques. Note that typically OPF analysis is performed using generation costs as the dispatch driver. However, if generation costs are not known, an alternative is to perform a "minimum control change" optimal dispatch. This type of OPF re-dispatches generation to alleviate overloads based on sensitivities of line flow to generation change, and changes the generation as little as possible to fix the overloads. The minimum control change OPF in this context can also be referred to as a "best case scenario" for renewable penetration, as it keeps the renewable resources dispatched at the highest level possible without any transmission violations.

- A second analysis that can be performed arises from the OPF scenario discussed previously concerning the identification of penetration levels. The strategy of this second analysis is to make use of the OPF algorithm as the basis for the hourly intermittency analysis. Each hour can be solved with the wind resource's maximum capability set to its hourly forecast capacity factor, the non-intermittent renewables set to their given maximum capacities, and the natural gas (or other non-RMR) units reduced to offset the renewables. The OPF then determines transmission violations and re-dispatches renewables and non-RMR units to alleviate the constraints. This process identifies the renewable dispatch needed for each scenario of different wind availability at each wind site for a constant modeled load period. Thus for each wind scenario the critical transmission elements are identified in the system and if the optimal renewable dispatch meets some minimum total renewable capacity for that hour. Given that the analysis focuses on holding load constant and varying the wind availability, one possibility for the minimum renewable penetration metric can be a capacity value of the total load, for example a target of 33% of the total load MW for each scenario. This type of analysis is in line with the intermittent analysis performed for the IAP study in that load is held

constant and focuses the affect on the transmission system to the variation of the wind resources only.

- A third analysis is a variant of the second analysis described above, in which the OPF is used for varying wind output for several forecasted wind scenarios, but includes load forecasts for each scenario as well and analyzes the transmission constraints identified in each scenario for both changing wind and load. This may be interesting from the point of view of the correlation of wind and load, and if any constraints appear affected by situations where wind and load are both increasing, both decreasing, or moving in opposite directions. This process can narrow the focus of specific transmission studies to the areas where the greatest wind/load diversity exists, thus providing a method of allocating limited financial resources toward the locations that exhibit the greatest impact on system operation and security.

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Glossary

AGC	automated generation control
AMWCO	aggregate megawatt contingency overload
AMWhCO	aggregate megawatt hour contingency overload
ATC	available transfer capability
California ISO	California Independent System Operator
COI	California Oregon Intertie
CPUC	California Public Utilities Commission
CSP	concentrated solar photovoltaic
DPC	Davis Power Consultants
DWR	Department of Water and Power
EAO	Electricity Analysis Office
GWh	Gigawatt-hour
IAP	Intermittency Analysis Project
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	investor owned utility
kV	kilovolt
LADWP	Los Angeles Department of Water and Power
MVA	megavolt-amperes
MVAR	megavolt-ampere reactive
MRTU	market redesign and technology upgrade
MW	megawatt
MWh	megawatt-hours
OPF	optimum power flow
PG & E	Pacific Gas and Electric
PV	photovoltaic

P-V	power voltage
QV	reactive power-voltage
RAS	remedial action schemes
RMR	reliability must run
RPS	Renewables Portfolio Standard
RTBR	renewable transmission benefit ratio
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SMUD	Sacramento Municipal Utility District
SVA	Strategic Value Analysis
VAR	voltage-ampere reactive
WECC	Western Electricity Coordinating Council