California ISO

DRAFT

Integration of Renewable Resources

Report

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Transmission and Operating issues and recommendations for integrating renewable resources on the CAISO Control Grid

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Executive Summary

California is a national leader in the development of renewable resources as it positions itself at the forefront of diversifying resources and reducing greenhouse gases. Currently, more than 6,000 megawatts (MWs) of installed renewable resources[1] including wind, solar, geothermal, biomass and small hydroelectric generation help to “green the grid”. These resources delivered 21 million megawatt hours of energy to California electric customers in 2006. This represents 9 percent of the total energy required to serve load in the California Independent System Operator Corporation (CAISO) Control Area. To further develop environmentally friendly power, the state of California enacted a Renewables Portfolio Standard (RPS), requiring each retail seller of energy to procure 20 percent of their energy load from renewable energy resources by December 31, 2010. As a national leader in developing new initiatives to facilitate renewable development, CAISO initiated this study to ensure that the operation and design of the transmission grid fully support this renewable standard.

The CAISO is implementing two significant initiatives to facilitate the development and integration of renewable resources. First, in 2002, CAISO put into place its Participating Intermittent Resource Program (PIRP) to better integrate wind generators. This program was a major breakthrough, providing better forecasting of intermittent generating resources and thereby enabling wind generators to participate in the California markets without being penalized for the inherent intermittency of wind generation. As a further boost to all renewables, CAISO led a new initiative with FERC in 2006 called the Remote Resource Interconnection Program to provide a mechanism for transmission upgrades that will support renewable resources and permit transmission of renewable power from remote locations to load centers.

This Report is another major initiative by CAISO that addresses the operational and transmission impacts of increased renewable capacity and how the system can successfully integrate these increased resources. The Report builds on other integration studies, especially CEC’s Intermittency Analysis Project Final Report published in July 2007, by adding significant new analysis and study to the area of operations on intermittent generating resources.

The CAISO is working collaboratively with load serving entities, state and federal regulators, industry experts, adjacent control areas and the owners/developers of renewable resources to identify integration challenges and solutions. Because California has large quantities of renewable resources already on line, a significant amount of historical data is available to accurately model and forecast future performance of the various types of renewable resources. Small hydroelectric, biomass and geothermal generation are more predictable resources and the integration of these resources into both the markets and operations do not present significant problems. Concentrated solar is an intermittent resource, but the amount of generation from this resource is still small so it does not result in significant integration issues.

As noted above, wind generation, with its enormous benefit of diversifying California’s power supply, is the focus of this report. It presents the most integration issues because its volume is expected to grow faster in the near term and because the inherent intermittency adds to the challenges of meeting electricity demand on an instantaneous basis. During certain times, wind produces its highest energy output when the demand for power is at a low point. During some periods of the

[1] This figure of 6,000 MW and the analysis that follows from this figure only includes energy production from renewable resources located in the California ISO control area and therefore does not reflect renewable energy imported from adjacent control areas. Figures provided by the CEC, CPUC and IOU’s may be higher than the amount stated above because such figure may additional include the above referenced imports.

year, wind generation is hard to forecast because it does not follow a predictable day-to-day production pattern. Much of the increased wind resource installations are expected in the Tehachapi region in Southern California. During the summer months, the Tehachapi area has a repeating pattern of maximum wind generation at night, a ramp down of energy production during the morning load pick up period, and a ramp up of generation in the evening. Integration of large amounts of wind generation is technically feasible, but there are transmission, operating and forecasting challenges. The focus of this report is to discuss these integration issues and, more importantly, the proposed solutions and recommendations to meet these challenges and facilitate renewables integration in California and the West.

This Renewables Integration Report focuses on two major areas:

1. The transmission plans for interconnecting renewable resources and

2. Operating issues involved in integrating large amounts of wind generation.

The results of these studies are described in detail in this report and in the attached appendices.

Transmission Plan for Renewable Resources

The largest increase in renewable energy resources between now and 2010 will be from wind generation, and the majority of this new wind generation will come from the Tehachapi Wind Resource area. Given these facts, we will use the results of our transmission system analysis of the Tehachapi area and the unique characteristics of renewable resources, to model and forecast our transmission plans for renewable resources. The Tehachapi Transmission project was reviewed in detail to reassess the adequacy of the voltage controls, transient stability and post transient voltage performance of the system. Standard power flow, transient stability, and voltage stability analysis tools were used to assess the transient stability and voltage stability of the system with the addition of various levels of wind generation planned for the Tehachapi area. The objective of the study was to assess the overall performance of the interconnected transmission system over a broad range of load, wind generation levels and wind turbine assumptions. The CAISO Regional Transmission Department and GE Energy Consulting performed a joint transmission analysis of the Tehachapi Transmission Project.

The primary objectives of the transmission system analysis were as follows:

1. Evaluate transient stability and post transient voltage performance of the CAISO Controlled Grid with increased levels of wind generation in the Tehachapi area.

2. Evaluate the post-transient voltage stability performance of the CAISO Controlled Grid with increased levels of wind generation in the Tehachapi area.

3. Evaluate wind plant functional characteristics that are necessary to achieve acceptable static and dynamic performance of the CAISO Controlled Grid.

4. Determine any needed improvements to the Grid to achieve acceptable performance with increased levels of wind generation and other renewable energy resources.

The system analysis focused on a 20 percent renewable energy requirement with 4,146 MW of wind generation in the Tehachapi area. The proposed new 500 kilovolt (kV) transmission facilities for the area and the static and dynamic reactive compensation devices were included in the modeling of the transmission system.

The Western Electric Coordinating Council (WECC) 2010 Heavy Summer peak load and 2012 Light Spring load system conditions with 4,146 MW of total wind generation were modeled in the Tehachapi area.

For each seasonal condition, three wind generation scenarios were analyzed:

1. Full Wind, where all Tehachapi area Wind Turbine Generators are on line operating at rated MW;

2. Low Wind, where all Tehachapi area Wind Turbine Generators are on line operating at 25 percent of rated MW; and

3. No Wind, where all Tehachapi area Wind Turbine Generators are off line.

For each scenario, the baseline analysis was performed assuming that all new wind plants would be Type 3[2] doubly fed wind turbine generators. The existing wind plants in the Tehachapi area were modeled as Type 1 conventional induction generators. A total of 23 contingencies (11 categories B and 14 categories C)[3] were simulated for each of the seasonal wind generation scenarios. Finally, several sensitivity studies were performed by varying the mix of Wind Turbine Generator types based on the actual installations of new wind plants in the U.S. in 2006 (i.e., 10 percent Type 1 induction generator, 20 percent Type 3 doubly fed with power factor control, 50 percent Type 3 doubly fed with fast voltage regulation and 20 percent Type 4 full converter induction generators).

Conclusions from the Transmission Planning Study

The study concluded that the Tehachapi transmission plan is sound and there are no serious transient stability or post-transient voltage stability problems. It does however point out the need to address some very important issues:

1. All new wind generation units must have the capability to meet the WECC requirements of ± 0.95 power factor. This reactive capability is essential for adequate voltage control.

2. The proposed Tehachapi Transmission Project can support up to 4,200 MW of wind generation in the Tehachapi area, providing that the new wind plants adhere to the WECC Low Voltage Ride Through (LVRT) criteria.

    - The existing Type 1 wind generators in Tehachapi do not meet this standard and the studies show these units will trip off-line following a short circuit problem in the area. Type 3 and 4 wind generators meet the LVRT standard and they will survive a short circuit event.

[2] The four types of wind generators are described in detail in Appendix F. Briefly Type 1 is a conventional fixed speed induction generator that operates synchronized to the power grid. It typically consumes VARS and does not meet Low Voltage Ride Through standards. Type 2 is similar to a Type 1 unit but it uses a wound rotor induction generator with variable rotor resistance. Type 3 is a doubly-fed induction generator that is synchronized to the power grid but uses a feedback loop that enables it to produces VARS and meets Low Voltage Ride Through standards. Type 4 is similar to Type 3 and it has a full converter interface.

[3] Category B is the loss of a single element while Category C refers to events resulting in the loss of two or more (multiple) elements.

3. Dynamic reactive capability for all new wind generation facilities is essential. CAISO should consider requiring that a minimum portion of the required power factor range be dynamic for each new wind park. Additional analyses will need to be performed to determine the minimum requirements for the dynamic range.

4. The bulk power system performed satisfactorily in both the transient and post transient states with 4,146 MW total wind generating capacity in the Tehachapi area.

5. The frequency response of the Western Interconnection is not affected by the addition of over 3,500 MW of new wind generation within the CAISO Control Area.

6. A sensitivity analysis study shows that system performance is acceptable with either all Type 3 doubly fed wind turbine generators or with a mix of wind turbine generator technologies for the new wind plants. The pessimistic test scenario with 100 percent Type 1 wind plants with no dynamic reactive capability shows an unacceptable response. This suggests that wind plants with some dynamic reactive capability are necessary to ensure system stability. Therefore, if the dynamic reactive capability is not inherent in the wind turbine generator, it may need to be added to the wind plant.

7. Based on the transient stability study results, the bulk system (500 and 230 kV) shunt capacitors and Static VAR Compensation (SVC) for dynamic voltage support proposed in the Tehachapi Transmission Project appear to be conservative for the level of wind generation and the system conditions/outages considered in this study. The SVC sensitivity analysis shows that the proposed SVCs were not necessary to achieve acceptable transient stability performance with a likely mix of wind turbine generator technologies.

8. The sensitivity analysis shows that the proposed SVCs were not sufficient to achieve acceptable dynamic performance if all of the new wind plants were modeled with 100 percent Type 1 wind turbine generators and had no dynamic reactive capability. This is a pessimistic assumption since the majority of the new wind plants that were installed in the U.S. in 2006 were of Types 3 and 4, which are capable of providing dynamic reactive support.

9. With adequate dynamic reactive capability and reasonable assumptions of wind plant operation, system transient stability performance is acceptable with fewer capacitors (and possibly smaller/fewer SVCs). This suggests that wind plants with some dynamic reactive capability may reduce or eliminate the need for dynamic reactive devices on the transmission system. Dynamic reactive power supplied close to where it is needed (e.g., at the Type 1 wind turbine generator terminals) will be more effective than the dynamic reactive power at a remote location for the potential problems identified in this transient stability analysis. This will require further analysis to determine the optimal size and location for the dynamic reactive support.

10. The post-transient analysis indicated that the grid performance met applicable WECC planning standards, specifically the post-transient voltage deviation and voltage stability reactive margins. Adequate reactive margins at critical 500 and 230 kV buses were observed for critical contingencies, varying between 950 MVAR and 3400 MVAR for 500 kV buses and between 600 MVAR and 1300 MVAR for 230 kV buses.

11. The post-transient analysis also indicated that the proposed transmission system to accommodate the additional new wind generation in the Tehachapi area may be highly compensated with the addition of mechanically switched shunt capacitors. The nose point in

the resulting Q-V curves for critical 500 kV buses under critical contingencies was observed to be high in the 0.95 – 1.0 per unit voltage range. Further analysis will be needed to optimize the proposed reactive supports and to evaluate if series compensation would be required to help lower the nose point in the Q-V analysis for critical buses under critical contingencies.

Recommendations Based on the Transmission Planning Study Results

1. All new wind generation plants must meet WECC LVRT requirements.

2. The majority of additional new wind plants must be Type 3 or Type 4 generators that are capable of providing dynamic reactive support to help the transmission grid meet applicable WECC transient stability performance standards and to prevent potential tripping due to low voltages. In the event that some of the new wind plants are of Type 1 or 2 with no dynamic reactive capability, additional studies will be required to determine the appropriate additional external dynamic reactive support that will be required.

3. Re-evaluate the optimal location and size for the dynamic reactive support (i.e., SVCs) that were proposed in the Tehachapi Transmission Project plan.

4. Analyze the best solution for improving the nose point of the Q-V analysis for critical 500 kV buses under critical contingency conditions. Potential solutions include the use of series compensation and reduction of proposed shunt compensation.

Analysis of Operating Issues

The primary objectives of the Operating Issues study were to determine:

- The magnitude of hourly overall ramping requirements

- Load following capacity and ramping requirements

- Regulation capacity and ramping requirements

- Over generation issues and potential solutions

The wind generation impact analysis methodology is based on a model of the actual CAISO's scheduling, real-time dispatch, and regulation processes and their timelines. Minute-to-minute variations and statistical interactions of the system parameters involved in these processes are depicted with sufficient details to provide a robust and accurate assessment of the additional capacity, ramping and ramp duration requirements that the CAISO Automatic Regulation Control (AGC) and load following Automated Dispatch System (ADS) systems will be facing in the year 2010.

Conclusions from the Operating Issues Study

1. Integrating 20 percent renewables in the California electric power system is operationally feasible, however changes to operating practices will be required (see Recommendations).

2. The 20 percent renewables is expected to increase the three-hour morning ramp by 926 MW to 1529 MW and the three-hour evening ramp by 427 MW to 984 MW depending on the season.

3. The CAISO regulation capacity requirements will increase by 170 MW to 250 MW for "Up Regulation" and 100 MW to 500 MW for "Down Regulation". The amount of increase varies

with the season and hour of the day. The fact that this increase in regulation requirements is ten times larger than in pervious studies is due to a new and improved model that more accurately represents the time lags in the Automated Dispatch System and in generator response to dispatch commands.

4. The CAISO regulation ramping requirements in 2010 is expected to increase by about ±15 to ±25 MW/min. These increases will affect AGC ramps up to 5-minutes long.

5. The CAISO will also require a significant increase in the supplemental energy stack to meet intra-hour load following needs. The increase is explained by the fact that the Hour-Ahead wind generation forecast error (standard deviation is evaluated as 7-9 percent of the total installed wind generation capacity) becomes comparable with the Hour-Ahead load forecast error (standard deviation is 600-900 MW). The increase in the use of supplemental energy could potentially increase the 10 minute real-time market clearing prices.

6. The CAISO maximum load following ramping requirements in 2010 is expected to increase by about ±30 to ±40 MW/min. These increases will affect ADS ramps up to 20-30 minutes long.

7. The CAISO current generating resources seem adequate to meet the anticipated ramping requirements for load following and regulation. However, during drought conditions or low hydro years, regulating response could be slow due to the reliance of thermal units with slower ramp rates. Depending on system load, additional units may have to be committed on-line to meet regulation needs, especially during the summer months.

Recommendations from the Operating Issues Study

1. Implement a state-of-the-art wind forecasting service for all wind generator energy production within the CAISO Control Area. This includes Day-Ahead, Hour-Ahead, and Real Time wind generation forecasts. These forecasts will be crucial for the unit commitment, scheduling, and dispatch processes in the Day-Ahead, Hour-Ahead and Real Time timeframes.

2. Incorporate the Day and Hour-Ahead wind generation forecasts (block energy schedules) into the CAISO's and SC's scheduling processes. The Day and Hour-Ahead schedules must be based on the forecasted wind generation values.

3. Integrate the Real Time wind generation forecast (average wind generation for 5-minute dispatch intervals) with the Real Time unit commitment and MRTU dispatching applications.

4. Develop a new ramp forecasting tool to help system operators anticipate large energy ramps, both up and down, on the system. The longer the lead time for forecasting a large ramp, the more options the operators have to mitigate the impact of the ramp.

5. Change the CAISO generator interconnection standards to require compliance of all intermittent resources with the interconnection rules established for the Participating Intermittent Resources program. These rules include real-time meteorological data and DPG telemetry systems to communicate the 4-second data meteorological and production data from wind parks to the CAISO. This data needs to be integrated into the CAISO's forecasting software.

6. Implement a procedure where the CAISO Dispatcher can send dispatch notices to wind generation operators and require them to implement pro-rata cuts in their energy production. During over generation periods, when dispatchable generation plants are already operating

at their minimum levels, the CAISO needs to have an ability to curtail wind generation on an as needed basis.

7. Analyze the impact of solar power intermittency with load and wind generation intermittency.

8. Evaluate technological changes that can facilitate the integration of large amounts of intermittent resources. For example, evaluate the benefits of participating in a wider-area arrangement like ACE sharing or Wide Area Energy Management system[4].

9. Study the impact that additional cycling (additional start ups) and associated wearing-and-tearing issues, dispatches below the maximum unit capacity and associated additional costs and environmental impacts will have on conventional generation due to the integration of large amounts of intermittent resources. We will consider if improvements can be made to the CAISO's Scheduling, Real Time Dispatch, and Regulation systems that will minimize the impacts on conventional units.

10. Encourage the development of new energy storage technology that facilitates the storage of off peak wind generation energy for delivery during on-peak periods.

11. Include changes in Resource Adequacy standard to require more generation with faster and more durable ramping capabilities that will be required to meet future ramp requirements[5].

12. Include changes in Resource Adequacy standard to require additional quick start units that will be required to accommodate Hour-Ahead forecasting errors and intra-hour wind variations.

Analysis of Forecasting Issues

The Market Redesign and Technology Upgrade (MRTU)[6] is expected to help in mitigating ramping problems associated with large amounts of wind generation provided that Day-Ahead and Hour-Ahead wind forecast are integrated into MRTU. There are occasional problems of too much generation on-line on light load days when wind and hydro generation are at maximum production levels. These high levels of production combined with other generation that must also be on-line results in an over generation problem. One of the important results from the MRTU Day-Ahead Integrated Forward Market (IFM) will be the creation of feasible generation schedules for the next operating day. IFM requires accurate Day-Ahead wind generation forecasts as a key input to the RUC process. The goal is to make sure that the right amount of generation is committed to be on-line for the next day operation. Good Day-Ahead market decisions will minimize the start up of fossil fueled generation that is not going to be needed when large amounts of wind generation shows up. Better Day-Ahead schedules will decrease the over generation problems as load and generation will be more closely matched.

[4] Principles of the Wide Area Energy Management system are currently under design at PNNL. The project is sponsored by BPA. The CAISO is a participant in this project.

[5] The CAISO is currently participating in a CEC-sponsored project with PNNL and ORNL on the value of fast regulation resources.

[6] MRTU is a comprehensive program that enhances grid reliability and fixes flaws in the CAISO markets. It keeps California compatible with market designs that are working throughout North America and replaces aging technology with modern computer systems that keep pace with the dynamic needs of California's energy industry. The program is scheduled for implementation March 31, 2008.

The second market issue is the procurement of optimum quantities of Ancillary Services in the Day-Ahead market. The amount of regulation services needed is going to increase by 200 to 500 MW, especially for some specific hours and for some seasons. Wind variability and unpredictability is much larger in January through April so we will need to procure more regulation in these months.

The amount of energy and number of bids in the Supplemental energy market will need to increase with the additional amounts of wind generation. The additional energy required will be as much as +800 MW (INC Bids) and -1,000 MW (DEC bids). This may result in more price volatility in the Real Time energy market due to the large variability of wind generation in certain hours and seasons.

Use of Storage Technology with Wind Generation

Additional storage capability would be of considerable benefit with the integration of large amounts of renewables, especially intermittent resources. Storage systems shift some of the off-peak energy production to deliver at peak periods. Some storage such as high-speed flywheel systems can provide regulation services and frequency control. Storage can also help with ramping issues by quickly absorbing excess energy when wind generation ramps up and it can deliver energy when wind ramps down.

At this point, the only proven and deployed storage technology is hydro pump storage. The 1,200 MW Helms pump storage facility***** that is owned and operated by PG&E is the largest storage facility on the system. This plant could be used in combination with Tehachapi wind generation, if the transmission facilities to the Gregg substation are upgraded. This would facilitate the transmission of the Tehachapi energy to the Helms Pump Storage plant and it would enable the use of the third pump at the plant to store more energy from renewables for more hours per year.

Major R&D projects are underway to develop new storage technology such as hydrogen production with use of carbon nanotube technology for storage of the hydrogen gas. Other projects include the testing of the VRB flow battery and the potential use of compressed air storage. The high-speed flywheel test was successfully concluded earlier this year and could be commercially deployed in a year. All of the other storage technologies appear to be a number of years in the future before they are commercially available.

Summary

1. The planned $1.8 billion of transmission upgrades for the Tehachapi area are sufficient to support up to 5,000 MW of new renewable resources.

2. New wind generation resources should be Type 3 or Type 4 units as the installation of more Type 1 units in Tehachapi has a negative impact on the reliability of the system.

3. All new generating facilities including new wind generation facilities must meet the CAISO Interconnection standards, provide 4 second operating data, and be prepared to act on dispatch notices from the CAISO Operations.

4. Integrating 20 percent renewables in the current generation mix is achievable; however several market integration and operational changes are required.

***** The Helms pump storage facility is rated for 1200MW in the generating mode and 900 MW in the pump mode.

5. Transient stability studies indicated that the new Tehachapi wind generation with Type 3 model, meet WECC LVRT as well as the WECC transient stability standard.

6. Some of the existing Tehachapi wind generation (Type 1 model) trips off-line for three phase 500kV faults in the local area under the full wind scenario.

7. Post transient governor power flow analysis results indicate that the WECC standards are met.

8. A state-of-the-art wind forecasting service is necessary in the Day-Ahead timeframe to minimize errors in the unit commitment process. The accuracy of Day-Ahead load and wind generation forecasts will affect the market clearing prices and unit commitment costs.

9. Additional generating capacity and ramping capability will be required to meet multi-hour ramps during the morning load increase coupled with declining wind generation. Operations will need to be able to quickly ramp down dispatchable resources during the evening load drop-off and accommodate increases in wind generation.

10. The amount of regulation required will significantly increase with large amount of new wind generation.

11. The size of the supplemental energy stack must significantly increase to meet intra-hour load following needs.

12. The CAISO must have the ability to curtail wind generation during over-generation conditions.

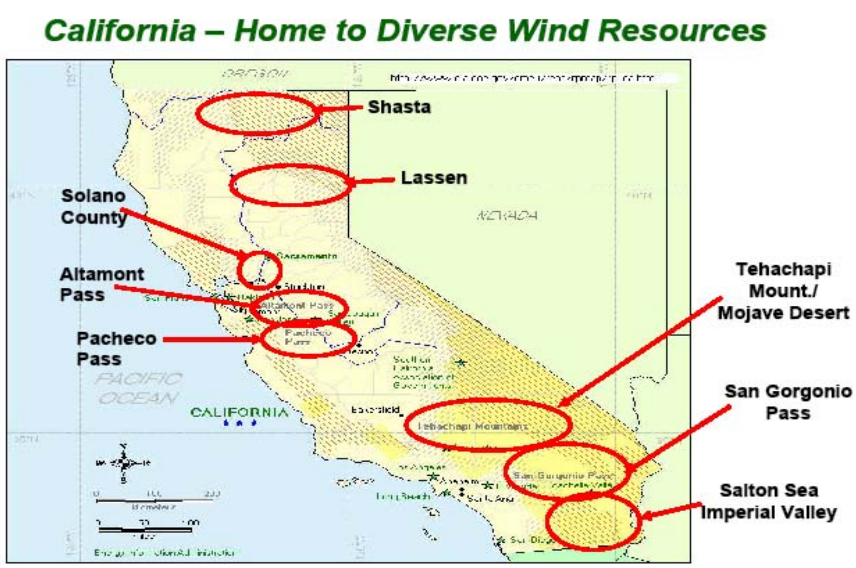
13. Short start units must be available to accommodate Hour-Ahead forecasting errors and intra-hour wind variations.

Chapter 1 - Background

The purpose of this Draft CAISO Integration of Renewable Resources Report (Report) is to ensure the successful integration of wind generation and other renewable resources with the planning, and operation of the power grid. The required Renewables Workgroup combines the talents and resources within Planning and Infrastructure Development (P&ID), Grid Operations, Market Operations, Information Technology and External Affairs and further representatives from General Electric, Battle Labs – Pacific Northwest Division and AWS Truewind. It also involves coordination and collaboration with IOU's, wind generator owner/operators, Scheduling Coordinators, the CEC, industry experts and adjacent control area operators.

The scope of this Report is a detailed focus on Transmission Planning and Operating Issues and secondarily, a focus on Market Issues and Use of Storage Technology. Our goal was to identify any voltage control problems, transient stability issues and transmission loading issues. The primary driver behind this Report is to ensure that any transmission control devices (SVC's, reactors, capacitors, etc.) needed by 2010 are ordered as soon as possible.

Chapter 10 of this Report addresses conclusions and implementation tasks going forward. These tasks will focus on the remaining Operational Issues and Market Issues. This includes the need for better Day-Ahead forecasting and use of this information for Day-Ahead Unit Commitment decisions. It also covers technical and market issues on the import of renewables.



1.1. Wind Generation Fundamentals

To address wind generation and integration issues, it is useful to have a common understanding of some fundamental facts:

1.1.1. Wind generation is an energy resource and not a peaking capacity resource

Because wind is an intermittent resource, it can not be counted upon in California to meet the peak loads on the hottest days of the year. Criticism that wind generation taken alone in California cannot be counted upon to help the CAISO meet the summer peak load is true. The wind typically does not blow on the hottest days of the year so the wind generation production is usually less than 10% of its nameplate capacity at the time of the summer peak load. Wind generation's role is to displace fossil fuel generation resources, to help the state meet greenhouse gas initiatives and carbon reductions, and to reduce the exposure to volatile natural gas prices. Utilities purchase the power output from wind generators to meet their RPS requirements, and to back down the power required from the more expensive gas fired power plants.

1.1.2. Wind Generation, solar generation and system load are all quite variable

The variability of any one of these items may be offset by the other or they can be additive and increase the total variability on the system. To accommodate this increase in variability, we need increase flexibility from other resources such as hydro generation, dispatchable pump loads, energy storage systems, and fast ramping and fast starting fossil fuel generation resources. The portfolio of future California resources must reflect this need for very flexible generation resources to assist with the integration of large amounts of intermittent resources. This required increased flexibility will be one of the cost drivers for integration for renewables.

1.1.3. The size of the control area matters

The larger the control area, the more diversified the resource areas, and the larger the benefits of aggregation. Production from geographically dispersed resources typically have much different meteorological conditions so they do not all move up and down together. The larger the amount of aggregation, the greater the reduction in variability and the easier it is to forecast the total renewables energy production.

1.1.4. The cost and complexity of wind integration starts low

The variability of wind generation energy production from a small number of units is usually much less than the variability of system load changes. The system operator is accustomed to dealing with daily load forecast errors, changes in hourly load forecasts, and the unpredictability of loads. As the amount of wind generation in an area increases, it will reach a point where its variability is greater than the variability of load. As wind generation further increases, the amount of variability will increase non-linearly. RPS goals to move from 20% to 33% energy from renewables could potentially more than double the integration problems and costs.

1.1.5. Forecasting of wind generation energy production, both Day-Ahead and Hour-Ahead is an essential integration strategy

Wind generation energy production is not typically scheduled in the Day-Ahead market. The forecast for wind generation energy production is a very important component in deciding what other generation should be scheduled for the next day. If 3,000 MW of wind is forecasted for the next day, it is inefficient and costly to start up fossil fuel generation that will not be needed. The CEC IAP study and other wind integration studies have pointed out the critical importance of Day-Ahead wind generation forecasts. The Day-Ahead forecast does not have to be 100% accurate to achieve substantial benefits.

1.2. Other Key Factors

1.2.1. Large ramps will be an issue

There will be periods where wind energy product rapidly declines while simultaneously the load is rapidly increasing. Energy ramps as high as 3,000 MW per hour or larger may occur between 0700 and 1000 hours. Fast ramping generation, such as hydro units, will be essential for the CAISO to keep up with the fast energy changes. There will be other periods, particularly in the winter months, where large pacific storms will impact the wind parks and their energy production will rapidly ramp up to full output. The solution is going to be the development of new ramp forecasting tools to help the grid operators.

1.2.2. Planning and managing transmission for renewable is a key strategy

Renewable resources can be built much faster than the required transmission upgrades can be designed, approved and built. New transmission and transmission upgrades are essential to link these locational constrained renewable facilities to the backbone power grid. New strategies are needed to manage the congestion on the transmission network to facilitate the maximum delivery of renewable energy to customer loads.

1.2.3. Coordination with neighboring control areas will be a key to success

For California to meet the 20% RPS goal, the CAISO will have to import some of the renewable energy from adjacent control areas. New rules and procedures will be needed to lower the barriers for import and export of intermittent resources between control areas. Coordinated transmission plans as well as coordinated energy scheduling and operating practices will be a key to success.

1.3. Renewables Portfolio Standard Goals

1.3.1. Twenty Percent (20%) Additional Renewable Resources - 2007 to 2013

Energy from renewable resources is expected to increase by 130% in the next five years. This large increase is driven by the State's Policy on Renewables Portfolio Standard, which requires the IOU's to serve 20% of their customers load from renewable resources by the year 2010. The CEC's forecast of the renewable mix by 2010 is shown in Figure 1 below:

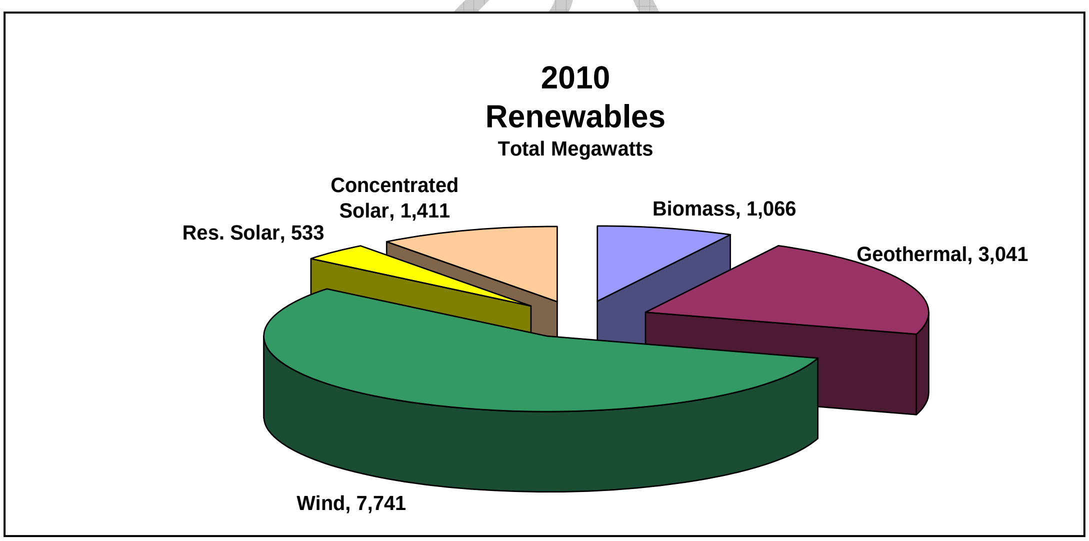


Figure 1: CEC Renewables Forecast Breakdown for 2010

The expected increase in energy renewable resources is as follows:

Table 1: California Energy Commission Renewables Forecast

Resource	Existing MW	Forecasted Additions MW	20% Renewables Total MW
	2006	**2010**	**2010**
Biomass	845	221	1,066
Geothermal	1977	1,064	3,041
Wind	2706	5,035	7,741
Res. Solar	Unknown	533	533
Concentrated Solar Power	465	946	1,411
Total	**5977**	**7,799**	**13,792**

The CAISO interconnection queue for renewable resources through the year 2013 contains 14,116 MW of wind generation and 11,264 MW of solar generation. It is not anticipated that all the generation in the interconnection queue will be built by 2013 so our studies and the CEC studies have scaled back the amount of new renewables generation to the numbers shown in the table above. The transmission and operating plans and recommendations contained in this report are based on the scaled back amount of renewables that's forecasted to be installed by 2010.

1.3.2. Thirty-Three Percent (33%) Additional Renewable Resources – 2020[7]

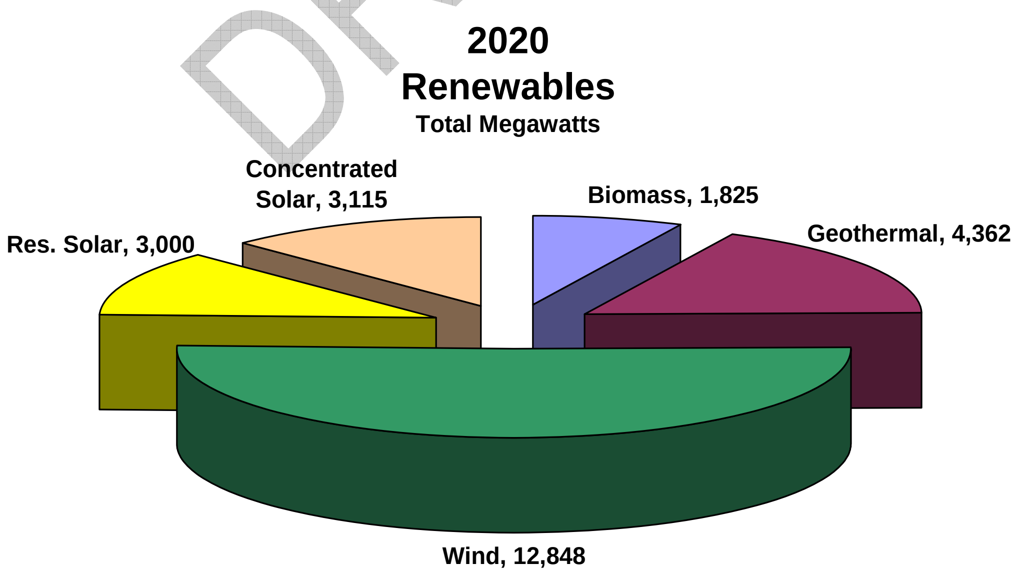


Figure 2: CEC Renewables Forecast for 2020

[7] CEC PIER August 15, 2006 Workshop on Intermittency Analysis Project

Table 1: CEC Renewables Forecast for 2020

Resource	Existing MW	Forecasted Additions MW	Total MW
	2006	**2020**	**2020**
Biomass	845	980	1,825
Geothermal	1,977	2,385	4,362
High Wind	2,706	9,961	12,667
Low Wind	0	181	181
Res. Solar	Unknown	3,000	3,000
CSP	465	2,650	3,115
Total	**5977**	**19,157**	**25,150**

The CEC IAP study for 2020 used 12,700 MW of wind and 6,000 MW of solar generation which is consistent with the numbers in the table above from their August 15, 2006 IAP workshop. The 33% RPS goal requires dramatic increase in solar generation as well as wind generation. Many of the most productive wind generation sites will be developed by 2020 or earlier so solar generation will have to play an increasing role to achieve the 33% RPS goal. The capacity value of the renewable resources typically is 20% to 37% of the name plate rating of the facility. The capacity value[8] of 30% means that for every 100 MW of installed nameplate capacity, the facility is only capable of delivering 30% to the total energy potential of the resource on an annual basis. The exceptions are biomass and geothermal resources which have capacity values of 89% and 90% respectively. Therefore, to increase the amount of energy from renewable resources from 20% to 33% requires approximately a doubling of the installed capacity of the renewable resources.

Note: This CAISO report on the integration of renewables covers only the 20% RPS requirement and does not include an analysis of the 33% goal. We will address our approach on the 33% target in Chapter 10 after we have a clearer idea on the integration of 20%..

[8] (Capacity Factor = actual energy production per year / Nameplate MW * 8765 hours per year).

Chapter 2 – Assessment of the California Energy Commission Intermittency Analysis Project Final Report

The California Energy Commission sponsored the Intermittency Analysis Project (IAP) in 2006 to study the integration of all renewable resources to meet the state's requirement of 20% of energy from renewables by 2010 and the target of 33% by 2020. A public workshop was held on February 13, 2007 where the results of this project were presented. The CAISO met with the consulting team after the workshop to discuss their findings. This included a discussion of the study methodology, the assumptions used in the study, and the results and conclusions in the DRAFT report. The CAISO provided detailed technical comments on the results presented at the workshop and recommended additional study work be done.

The Final IAP Report was released in late July 2007. This report is an excellent document with contributions from many experts and technical consultants. It provides a thorough analysis of many of the integration issues. The report concludes the 20% renewables requirement can be achieved but there are numerous things that must be done to insure success. It would be erroneous to conclude that there are no serious integration problems. In fact today's operating data with less than 3,000 MW of wind generation have already revealed some operating issues. The addition of 4,500 MW to 6,000 MW of new wind generation will only exacerbate these issues. The CAISO has worked with the CEC consulting team to correct some of the modeling assumptions to ensure the results produced are useful to the CAISO and all the participants in the renewables program.

One issue identified in the Draft Version of the IAP report that was released in May, 2007 was potential transmission and operating problems under light load conditions. If both hydro generation and wind generation are at maximum energy production and the system load is very low (less that 20,000 MW), there is a good chance the CAISO will have an over generation condition. There were also unanswered questions about the stability of the system and the potential for serious transmission voltage control problems during these conditions. To address these issues, CAISO and GE Energy, under CAISO's direction, jointly performed transient and post transient system analysis to determine the ability of the system to withstand disturbances and faults during off-peak periods. In addition, contractual and regulatory constraints on the operation of the system were considered in order to address additional mitigation measures. These studies were conducted during the summer 2007 and are the basis for a substantial portion of this CAISO report on the integration of renewables.

The Final IAP Report that the CEC released in July 2007 brings together many different pieces of work that have been done over the past several years. Its emphasis is on ALL forms of renewables resources, not just wind generation. It looked at various scenarios for the increase in the amount of renewable generation resources to uncover potential system problems. It examines transmission issues, operating issues, wind generation forecasting strategies, wind turbine technologies and modeling of wind generation, and a review of the international experience with the integration of renewable resources. This comprehensive PIER Project Report on the Integration of Renewable Resources will be nationally and internationally recognized as the standard of excellence for renewables integration studies.

The IAP report concludes that the electric system can successfully integrate the amount of renewable resources required to meet the 20% RPS target and even the 33% target if the many recommendations described in the report are adopted. Three things are key:

1. Major new transmission facilities and upgrades of existing transmission will be required, for the 20% RPS target and especially to accommodate the 33% RPS target;

2. Extensive changes will be required in the type of new generation built in the state as new units must have greater operating flexibility to start up and shut down without long delays, they must be able to operate at lower minimum loading levels, and they must have faster ramping capability and regulation capability;

3. Curtailment of some wind generation may sometimes be required, particularly during periods of minimum system load, high wind generation production, low conventional hydro generation flexibility and a lack of ability to export to excess wind generation to other areas.

2.1. Generation Resources Adequacy

The report has a series of important conclusions about future generation procurements and power exchange agreements. It emphasizes the critical importance of much greater flexibility in generator schedules and operational characteristics such as fast ramping, both up and down, and the ability to operate over a wide range of production levels.

It also concludes that the current practice of block hourly import and export schedules between balancing authorities may have to change to more frequent changes in schedules to accommodate the variability of renewable resources. This change may take some time to implement on a WECC wide basis but it could be tested and implemented between any areas that wanted to make the change.

The report also concludes that increase in the amount of regulation capability required "is relatively modest (20MW)." The CAISO disagrees with this conclusion and a major portion of our report describes a new methodology for calculating the amount of regulation required. This new methodology more accurately reflects the operation characteristics of the Automatic Generation Control (AGC) and the automatic Supplemental Energy dispatches required to rebalance the system every 5 to 10 minutes.

2.2. Transmission Infrastructure

The report correctly concludes that "Significant transmission investments are necessary to meet the 2010 and 2020 renewable targets." The 2020 case requires "128 new or upgraded transmission line segments" to meet load growth requirements as well as upgrades required to accommodate the new generation resources. The estimated transmission and substation costs are $6.4 billion plus land and right of way costs. All of these transmission expansion estimates are based on scenarios of where new renewable resources might be built and how many megawatts of capacity would be located at each site. The CAISO and the Transmission Utilities will have to develop detailed transmission plans to accommodate the proposed generation resources that have submitted interconnection applications.

2.3. Renewable Generation Technology, Policy, and Practice

The CAISO agrees with the conclusion that wind and solar energy forecasting will be very important to the success of the renewables program. If the energy production from renewables can not be forecasted and scheduled, then the value of renewables to displace fossil fueled generation is greatly diminished. The CAISO is looking forward to working with the CEC to develop the best possible forecasting tools to facilitate the integration of the renewable resources into the market schedules and operations.

The new wind turbine technology and solar technology overcome many of the operating limitations of the older technology. New storage technology and transmission congestion monitoring technology may significantly increase the amount of renewable resources that can be accommodated on the system. The increased availability of pump storage facilities (3 pump operation) can provide needed night time load to accommodate the increased amount of off-peak wind generation. New storage technologies should also be encouraged and tested within the state.

Regulatory policies that present barriers to the successful development of renewable resources must be identified and eliminated wherever possible. The report also correctly identifies that while operational flexibility of both loads and generation resources is highly desirable from a grid operations perspective, it may not be at all attractive to generation resources and schedulers. Market incentives may be required to secure the flexibility needed to operate the system with large amounts of intermittent resources.

2.4. New Wind Resource Areas

One of the key roles for the CEC is the identification of geographic areas within the state that have high potential value for location of renewable resources. The CAISO's strategy for transmission development to locational constrained resources is dependent on the CEC's identification of potential areas with significant wind, solar, and geothermal energy resources. The February 2007 IAP report "Characterizing New Wind Resources in California" is a good example of the research work that should be done to identify energy resource areas.

2.5. Operation Analysis of Intermittent Generation

The Operations Analysis report by the GE Energy Consulting team provides a very extensive analysis of the operational challenges from large amounts of intermittent resources. They have shown the combed effects of load variability, wind variability and solar variability. It is very encouraging to see how the combination of wind and solar together can reduce the variability of the entire fleet of intermittent resources. The results should be to encourage the continued R&D efforts on solar technology to drive down the cost of this technology and increase the opportunities for its deployment. The CAISO "Integration of Renewable Resources Report" uses the GE Energy Consulting team's report as the basis for the more detailed analysis performed. The CEC IAP report on the operational issues has been extensively reviewed at the CAISO as it reveals the operational challenges we will have to mitigate for the reliable operation of the grid with large amounts on intermittent resources.

2.6. Conclusion

The CAISO applauds the leadership of the CEC in undertaking the IAP study to assess the transmission infrastructure and services needed to accommodate the levels of renewable resources required by the state's policy goals.

Chapter 3 - Transmission Plans for interconnection of Renewables

This chapter of the report focuses on the addition of 3,540 MW of wind generation in the Tehachapi area. The Tehachapi area is located at the southern end of the San Joaquin Valley in the mountainous region between Bakersfield and Mohave and has the largest potential for the development of wind generation in California. As wind generation matured over the recent years, so to have requirements for specific performance characteristics of wind plants. The grid performance of individual wind turbine generators and wind plants has changed, and is substantially affected by the wind turbine technology. With large MW and penetration levels, wind generation performance is expected to be similar to that of other generating resources. Consequently, the past history of relatively poor grid behavior due to old wind generation is not representative of new wind generation.

Interconnection requirements are still evolving, and new WECC and FERC requirements for wind plant performance have been created. These requirements, which must be satisfied by new wind plants in the California grid, are expected to relieve some of the problematic behavior of older wind plants. Throughout the work presented in this report, analysis is based on the addition of wind generation that is, at least, compliant with the minimum performance standards currently in effect.

The analysis were conducted jointly between the CAISO and General Electric and entailed traditional power flow, transient stability and post-transient voltage stability analysis to assess the overall impact of renewables integration on the performance of the interconnected transmission grid over a broad range of load and wind turbine technology assumptions. The primary objectives of the studies were to determine compliance with the WECC reliability standards for transient and post-transient conditions. In addition, the studies also evaluated whether the new and existing wind plants meet the Low Voltage Ride Through (LVRT) standards and remain on-line during fault conditions.

Assumptions and Study Methodology

All studies were performed using the WECC 2010 Heavy Summer peak load and the WECC 2012 Light Spring load system conditions with 4, 200 MW of total wind generation modeled in the Tehachapi area. Appendix G covers the transmission planning process and studies performed to determine the transmission infrastructure and reactive requirements required to accommodate up to 4,372 MW of overall generation in Tehachapi.

Assumptions

- Existing Tehachapi wind generation: 722 MW (mostly connected to Tehachapi 66 kV system) modeled with WECC Type 1 fixed speed conventional induction generator
- Total new generation for the Tehachapi Transmission Project is 4,372 MW, of which 3,540 MW is new wind generation and 832 MW is comprised of combine cycle and gas turbine.
- No dynamic switching of any shunt capacitors was included in the transient stability analysis.
- Reactive support modeled in the studies:
  - The Existing Tehachapi wind generation area was modeled with 317 MVAR voltage-controlled shunt capacitors and 500 MVAR fixed shunt capacitors.

- The proposed new reactive supports for the new generation were 700 MVARs of voltage-controlled shunt capacitors, 917 MVAR of fixed shunt capacitors and two Static VAR Compensators totaling 800 MVAR (one at Antelope and the other at Vincent 500 kV Substations).

- 1,300 MVAR fixed shunt capacitors were modeled at wind plants.

2010 Summer Peak Load conditions – 2010 Summer Peak Load with 1-in-10 year heat wave demand for Southern California and corresponding peak load in Northern California. Three variations of the Tehachapi wind generation level were studied (1) wind generation energy production at nameplate capacity, 474 MVARs of 230 kV shunt capacitors in the Tehachapi area were turned off due to bus voltage greater than 1.05 leaving 869 MVAR in service (2) wind generation at 25% of rated nameplate capacity, with all 230 kV shunt capacitors in the Tehachapi area turned off and (3) wind generation plants off-line, with all 230 kV shunt capacitors in the Tehachapi area turned off. For the studies all new WTGs were set to regulate terminal voltage to 1.03 per unit. The studies were conducted using the following assumptions:

Table 1: Study Assumptions for 2010 Heavy Summer

	Summer 2010 Peak Base case MW
COI (Path 66) (N to S)	4,284
Path 15 (N to S)	617
Path 26 (N to S)	4,000
PDCI (N to S)	2,000
West of Borah (E to W)	912
Bridger West (E to W)	1,951

2010 Light Spring Load Conditions – Light Spring Load conditions with heavy South to North flows on Path 15. Similar to the summer studies, three variations of the Tehachapi wind generation level were studied as follows:

1. wind generation energy production at nameplate capacity;

2. wind generation at 25% of rated nameplate capacity with all 230 kV shunt capacitors in the Tehachapi area turned off, and

3. wind generation plants off-line with all 230 kV shunt capacitors in the Tehachapi area turned off. The studies were conducted using the following assumptions:

Table 2: Study Assumptions for 2012 Light Spring

	Spring Off-Peak MW
COI (Path 66) S to N	3,542
Path 15 (S to N)	5,400
Path 26 (S to N)	1,583
PDCI (S to N)	2,200
West of Borah (E to W)	1,256
Bridger West (E to W)	2,000

The baseline analysis for all studies was performed assuming that all new wind plants would be equipped with the WECC Type 3 doubly fed wind turbine generators. The existing wind plants in the Tehachapi area were modeled as WECC Type 1 conventional induction generators. A total of twenty three contingencies (11 Category B[9] and 12 Category C[10]) were simulated for each of the seasonal wind generation scenarios. The simulation consists of time-domain simulation following the disturbances to evaluate the system transient stability performance and governor power flow to evaluate the post-transient steady state performance.

Finally, several sensitivity studies were performed with varying the mix of the WTG technologies of the new plants based on the actual installations of new wind plants in 2006 (i.e., 10% Type 1 induction generator, 20% Type 3 doubly fed with power factor control, 50% Type 3 doubly fed with fast voltage regulation and 20% Type 4 full converter induction generators.

Conclusions

1. With the support of the proposed Tehachapi Transmission Project, 4,200 MW of wind generation in the Tehachapi area can be integrated to the system without causing any transient stability concerns, providing that the wind plants adhere to the WECC LVRT criteria and have some dynamic reactive capability.

2. The dynamics of the bulk power system are not significantly affected by high levels of wind generation (4,200 MW total) in the Tehachapi area. Both transient stability and system damping are satisfactory.

3. The addition of over 3,500 MW of new wind generation, on a system with over 100 GW of total generation at light load, has little impact on the frequency response following loss of major generation units (i.e., two Palo Verde nuclear generating units).

4. Adherence to the present WECC LVRT requirements for new wind plants is essential for helping to maintain the wind generators on-line under severe fault conditions.

5. Dynamic reactive capability at wind plants is required to meet the WECC transient dip performance criteria. Some types of wind turbine technologies include dynamic reactive capability while other types do not (i.e., WECC Types 3 and 4 do have capability to provide dynamic reactive capability while Type 1 does not). Without adequate dynamic reactive capability, wind plants can be expected to trip following major system faults. Voltage dips and spikes, in violation of the WECC criteria, can be expected if a significant number of wind plants connect to the grid without dynamic reactive capabilities.

6. Dynamic reactive capability at wind plants is necessary to ensure system stability. Technology sensitivity analysis shows that system performance is acceptable with either all Type 3 doubly fed WTGs or with a mix of WTG technologies for the new wind plants. The pessimistic test scenario with 100% Type 1 wind plants with no dynamic reactive capability shows an unacceptable response. Therefore, if the dynamic reactive capability is not inherent in the WTG, it may need to be added to the wind plant.

[9] Category B is the loss of a single element.
[10] Category C is event(s) resulting in the loss of two or more (multiple) elements.

7. The CAISO may consider requiring that a minimum portion of the required power factor range be dynamic for each new plant. Additional analyses will need to be performed to determine the minimum requirements for the dynamic range.

8. Based on the transient stability and post-transient study results, the bulk system (500 and 230 kV) shunt capacitors and SVCs proposed in the Tehachapi Transmission Project appear to be conservative for the level of wind generation and the system conditions/outages considered in this study. The SVC sensitivity analysis shows that the proposed SVCs were not necessary to achieve acceptable transient stability performance with a likely mix of WTG technologies. With adequate dynamic reactive capability and reasonable assumptions of wind plant operation, system transient stability and post-transient performance is acceptable with fewer capacitors (and possibly smaller/fewer SVCs). This suggests that wind plants with some dynamic reactive capability may reduce or eliminate the need for dynamic reactive devices on the transmission system. Dynamic reactive power supplied close to where it is needed (e.g., at the Type 1 WTG terminals) will be more effective than the dynamic reactive power at a remote location for the potential problems identified in this transient stability analysis. This will require further analysis to determine the optimal size and location for the dynamic reactive support.

9. The sensitivity analysis shows that the proposed SVCs were not sufficient to achieve acceptable dynamic performance if all of the new wind plants were modeled with 100% Type 1 WTGs and had no dynamic reactive capability. This is a pessimistic assumption since the majority of the new wind plants that were installed in the U.S. in 2006 were of Types 3 and 4 which provide dynamic reactive support.

10. The post-transient analysis indicated that the grid performance met applicable WECC planning standards, specifically the post-transient voltage deviation and voltage stability reactive margins. Adequate reactive margins at critical 500 and 230 kV buses were observed for critical contingencies, varying between 950 MVAR and 3400 MVAR for 500 kV buses and between 600 MVAR and 1300 MVAR for 230 kV buses.

11. The post-transient analysis also indicated that the proposed transmission system to accommodate the additional new wind generation in the Tehachapi area may be highly compensated with the addition of new shunt capacitors. The voltage nose point in the resulting Q-V curves for critical 500 kV buses under critical contingencies is high in the 0.95 – 1.0 p.u. voltage range. Further studies will be required to optimize the coordination between dynamic and static shunt reactive supports and also to evaluate if series compensation would be required to help lower the nose point in the Q-V analysis for critical buses under critical contingencies (i.e., tripping of one SONGS unit while the other unit was already out of service in the power flow case).

Recommendations

1. The new wind plants need to comply with WECC LVRT requirements.

2. The majority of additional new wind plants need to be of WECC Types 3 or 4 for producing dynamic reactive support to help the transmission grid meet applicable WECC transient stability performance standards and to avoid wind generators tripping due to low voltage conditions. In the event that the new wind plants are of Type 1 or 2 with no dynamic reactive capability, additional studies will be required to determine the appropriate amount of external dynamic reactive support at these wind plants.

3. The proposed reactive support that was proposed as part of the Tehachapi Transmission Project may need to be re-evaluated to determine the optimal location and size for the dynamic reactive support (i.e., SVCs).

4. Additional analysis will be needed to determine potential solution for improving the nose point for critical 500 kV buses under critical contingency conditions. Potential solution for improving the voltage nose point includes the use of series compensation and reduction of proposed shunt compensation.

Wind Plant Representation in the Power Flow

Since wind plants normally consist of a large number of individual WTGs, the modeling of the plant for load flow analysis could be simple or could consist of a detailed representation of each WTG and the collector system. The simpler model shown in Figure 1 is adequate for most bulk transmission system studies. This model consists of a single WTG and unit transformer with MVA ratings equal to **N** times the individual device ratings, where **N** is the number of WTGs in the wind plant (or those considered to be on-line for study purposes). An equivalent impedance to reflect the aggregate impact of the collector system can be included together with the substation step-up transformer(s). The total charging capacitance of the collector system can also be included. The charging capacitance can be significant since underground cables are often used for the collector system. A third alternative is to model several groups of WTGs, each represented by a single model, with a simplified representation of the collector system. The wind plants included in this study use both of these equivalent modeling approaches.

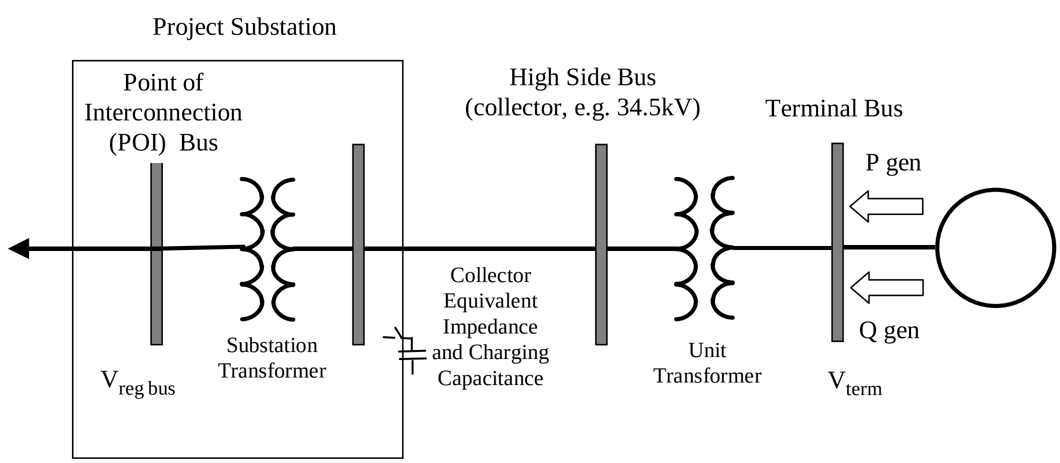


Figure 1: Wind Plant Equivalent Model

From an analysis perspective, it is important to understand that the aggregate WTG behaves like a conventional generator connected to a voltage control (PV) bus in the power flow analysis. The generator real power (Pgen) and reactive capability (Qmax and Qmin) are input to reflect the aggregate WTG capability. Typical collector system voltages are at distribution levels (typically 12.5 kV or 34.5 kV) from where a suitable sized substation transformer is used to connect to the grid. Some of the wind plant models in this study include shunt capacitors on the collector side of the substation transformer, as illustrated in Figure 1 above. These capacitors replace or augment reactive capability from the WTGs, so that the power factor requirement of the grid code is met.

Dynamic Modeling Discussion

As noted above, wind generation technology has evolved rapidly in recent years. Dynamic modeling of wind generation, particularly newer technology WTGs, is a challenge for the industry. The Western Electricity Coordinating Council (WECC) Modeling & Validation Work Group (MVWG) convened a Wind Generator Modeling Group (WGMG) in 2005 to address the challenge. The charter of that group was to “develop a small set of generic (non-vendor specific), non-proprietary, positive-sequence power flow and dynamic models suitable for representation of all commercial, utility-scale WTG technologies in large scale simulations.” The models are suitable for typical transmission planning and system impact studies. All of the current commercially available utility scale wind turbines can be grouped into four basic topologies based on how they interface with the grid. The notation that the workgroup adopted, and which is gaining industry acceptance, is:

Type 1 – conventional induction generator

Type 2 – wound rotor induction generator with variable rotor resistance

Type 3 – doubly-fed induction generator

Type 4 – full converter interface

Simple schematics of these four topologies are shown in Appendix F (again, courtesy of the WECC WGMG). Dynamic simulations performed have been based on available industry data and current state-of-the-art models of these different generators.

Transient Stability Characteristics of Wind Turbine Technologies

The transient stability behavior of the various WTG technologies can be substantially different. Outages that cause deep voltages dip can be problematic for Type 1 plants. A severe voltage dip may cause the induction generators to speed up and eventually pull out of their torque-speed characteristics. This causes them to trip. This response is similar to an induction motor stalling and tripping following a system fault. The risk of tripping is a function of machine characteristic, initial wind power, grid stiffness and dynamic reactive power supply. This type of trip is not a violation of LVRT requirements, as the unit tripping occurs after the fault is cleared. It should be noted that the existing Type 1 plants may or may not have LVRT capability. Therefore, it is possible that the existing plants would trip sooner than these simulations indicate. In cases with new Type 1 plants, they must be LVRT compliant, but they may still trip due to this overspeed behavior.

Since Type 3 and Type 4 machines are variable speed, these machines are not constrained by conventional transient stability angular constraints. These machines can not lose local angular stability like a synchronous machine, although it is possible for grid separation to occur. The variable speed controls tend to make this type of wind generator largely unsusceptible to low frequency grid oscillations as well.

Transient Stability Performance

Transient stability simulations were performed on the heavy summer and light spring cases for all three wind generation scenarios. Baseline simulations modeled all new wind projects with WECC Type 3 WTGs (doubly-fed induction generator). Existing wind farms in the Tehachapi area were all modeled with WECC Type 1 WTGs (induction generators).

Twenty-three single line, double line, generation trip and HVDC outages were studied for the two system conditions (heavy summer and light spring) and three wind conditions (full, low and no wind). System performance was evaluated based on "WECC Planning Standards, WECC Disturbance-Performance Allowable Effects on Other Systems". In particular, voltage and frequency dips violating the WECC criteria at load buses in California were identified. Tripped wind turbine generators were also identified.

A discussion of system performance with high concentrations of new wind generation follows.

Voltage Dip and WTG Tripping

None of the contingencies tested caused violations of the WECC voltage dip criteria.

All faults at the Vincent 500 kV and 230 kV buses caused existing Type 1 induction generator wind turbines to trip. In addition, faults at Lugo, Midway, Mira Loma and Sub 5 involving loss of lines to Vincent caused existing Type 1 wind turbines to trip. The amount of tripped generation ranged from 36 MW (3-phase, 4-cycle fault at Mira Loma 500 kV, loss of Vincent-Mira Loma 500 kV Line) to 270 MW (faults at Vincent 500 kV or 230 kV). The Type 1 generators only tripped when operating at full output. Trips occurred for both heavy summer and light spring conditions.

Figure 2 shows the response to the Vincent-Antelope fault and double line outage for the 2010 heavy summer base case. The full wind (black), low wind (red) and no wind (green) conditions are all shown on the plots. The figure shows the Antelope 500 kV bus voltage, Antelope SVC output, Antelope frequency, Plant 161 230 kV voltage, Path 26 power flow and San Onofre Unit 2 power output.

The voltage recovery seen at Antelope 500 kV and Wind Plant 161 230 kV following fault clearing is slower under full wind conditions than with low or no Wind. This is primarily due to the response of the existing Type 1 induction generator wind turbines. This outage results in 270 MW of tripped wind turbines, all existing Type 1 units.

There is a slight difference in the Path 26 power flow and the San Onofre power output, but overall the addition of 3,540 MW of new Type 3 wind turbines has little impact on the system response to a major three phase fault with a double circuit outage.

None of the stability cases resulted in new Type 3 doubly-fed induction generator wind turbine trips.

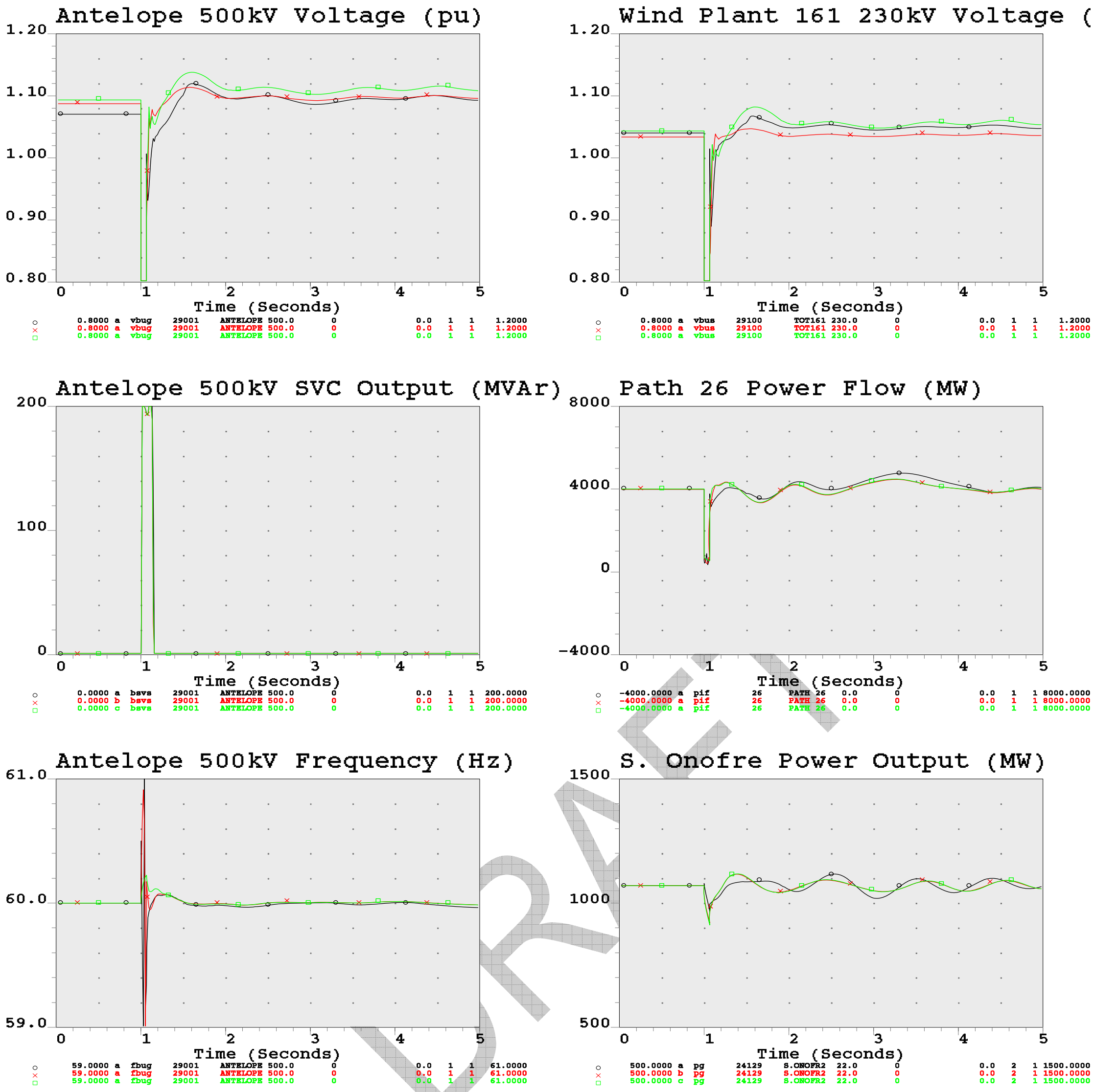


Figure 2: System Performance Overview, Vincent-Antelope 500 kV Double Line Outage, 2010 Heavy Summer Load, (Black=Full Wind, Red=Low Wind, Green=No Wind)

Frequency Response

None of the contingencies resulted in WECC frequency dip violations. Furthermore, there was no measurable difference in the system frequency between the full wind, low wind and no wind cases for the generation trip contingencies. A comparison of the three wind conditions is shown in Figure 3 for the loss of two Palo Verde generators. The Antelope frequency, Path 26 power flow, and San Onofre power output are all nearly identical for the three wind conditions.

The frequency at Antelope dips down to about 59.7 Hz and begins to recover within about 8 seconds of the generation trip. The addition of 3,540 MW of new wind generation, on a light spring system with over 100 GW of total generation, has little impact on the frequency response following loss of 2,820 MW of generation.

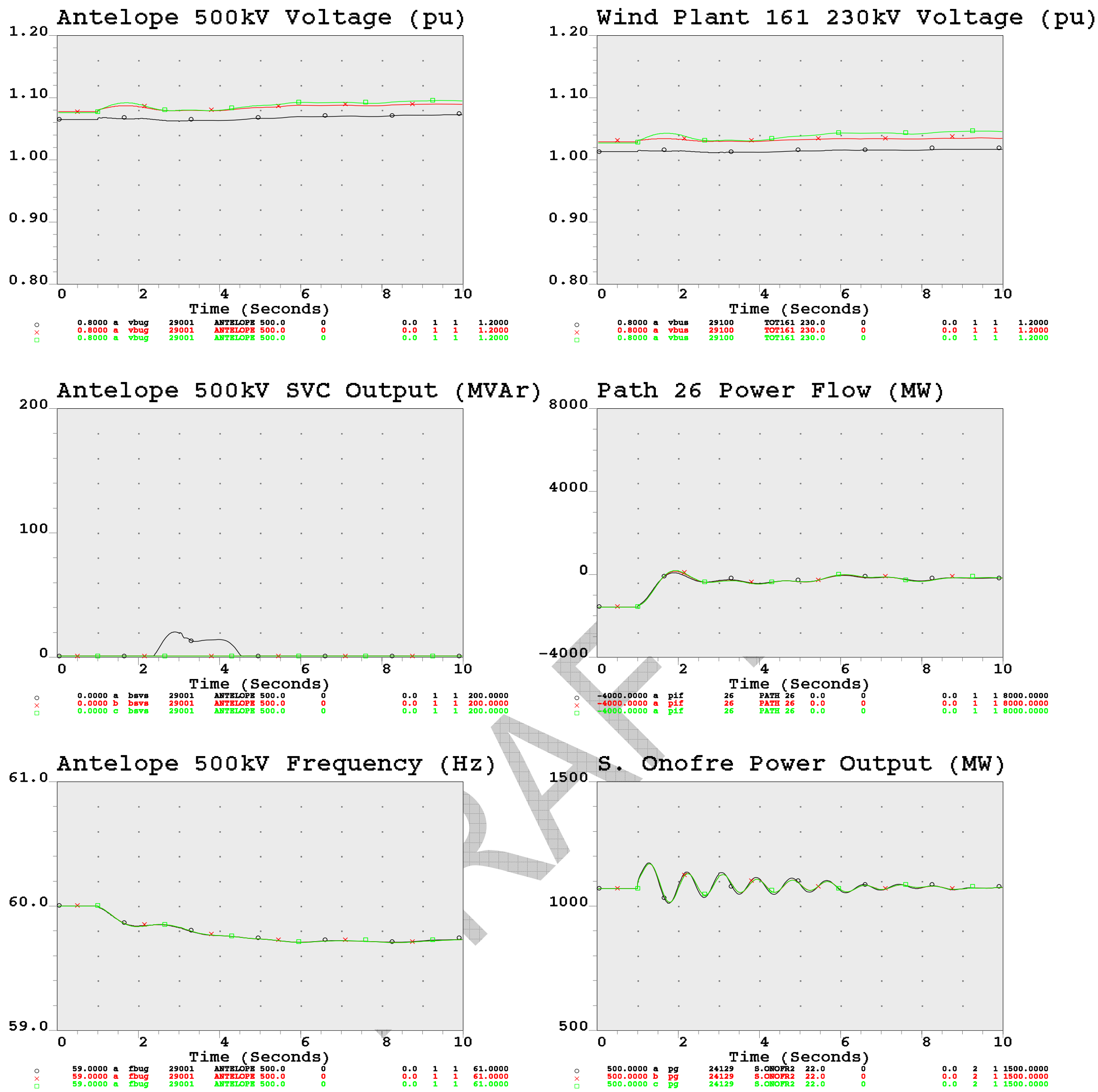


Figure 3: System Performance Overview, Loss of Two Palo Verde Generators, 2012 Light Spring Load, (Black=Full Wind, Red=Low Wind, Green=No Wind).

Power Swings

The plots in Figure *4* and Figure *5* show very little difference in power swings on Path 26 or San Onofre power output for the different wind scenarios. Thus, the addition of over 3,500 MW of wind generation at Tehachapi and the associated redispatch of existing generation does not affect power swings on the California system.

WTG Technology Sensitivity Cases

The sensitivity of power system performance to WTG technology was tested for the most severe faults identified in the baseline analysis. As noted above, the baseline analysis was performed assuming all new wind plants would use Type 3 doubly fed WTGs. Two additional scenarios were evaluated. The first assumed a mix of WTG technologies in the new plants, as follows:

- 10% Type 1 induction generator
- 20% Type 3 doubly fed with power factor control
- 50% Type 3 doubly fed with fast voltage regulation
- 20% Type 4 full converter

This mix was based on the technology distribution of the wind plants or individual WTGs installed in 2006.

The second scenario assumed all new wind plants would use Type 1 induction generator WTGs. Given the 2006 technology distribution, this is a pessimistic scenario.

A comparison of system performance for the three WTG technology scenarios is shown in Figure ***4*** . The Vincent-Antelope 500 kV double line outage was applied to the light load system with full wind plant output. The black line represents the baseline performance with 100% Type 3 doubly fed wind plants, the red line represents the mixed WTG technology scenario, and the green line represents the 100% Type 1 induction generator scenario.

System response with all new wind plants using Type 3 doubly fed WTGs meets WECC voltage and frequency criteria, and results in the loss of 270 MW of existing Type 1 induction generator wind plants. System response with the mix of WTG technologies in the new wind plants also meets WECC voltage and frequency criteria, and results in the loss of 270 of existing Type 1 wind plants. System response with all new wind plants using Type 1 WTGs was unacceptable. Approximately 4,200 MW of Type 1 wind plants, both old and new, tripped during the simulation.

System performance is acceptable with all Type 3 doubly fed WTGs in the new wind plants. System performance is also acceptable with the mix of WTG technologies in the new wind plants, but the fault recovery is slightly slower. Thus, the wind plants with dynamic VAR capability (i.e., Type 3 doubly fed and Type 4 full converter) support those without such capability. As noted above, the new Type 1 induction generator wind plants in this analysis are WECC LVRT criteria compliant but do not have any dynamic VAR range. Thus, the pessimistic test scenario with 100% Type 1 wind plants with no dynamic VAR capability showed an unacceptable response. This sensitivity analysis suggests that wind plants with some dynamic VAR capability may be necessary to ensure system stability. Therefore, if the dynamic VAR capability is not inherent in the WTG, it may need to be added to the wind plant.

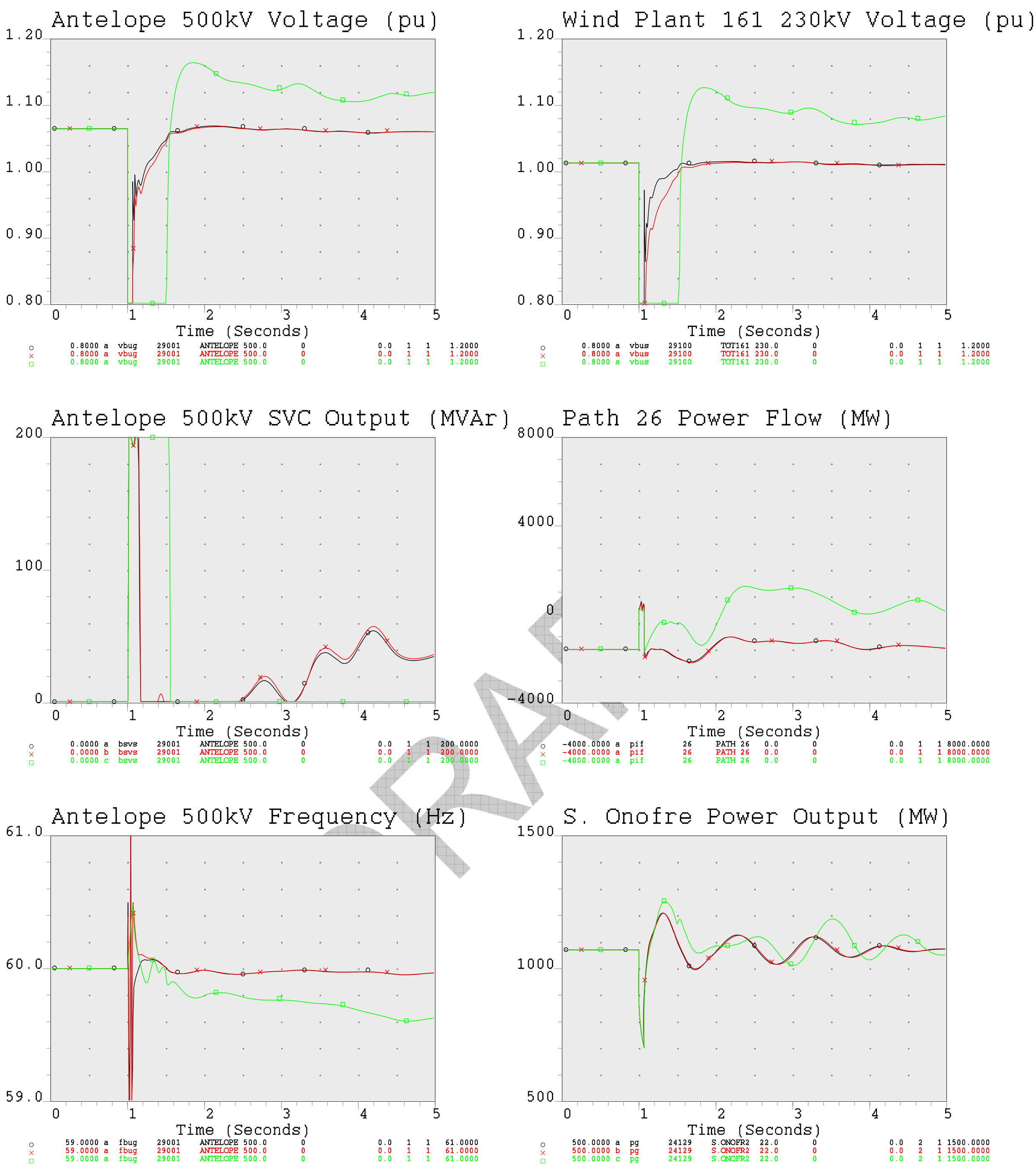


Figure 4: System Performance Overview, Vincent-Antelope 500 kV Double Line Outage, 2012 Light Spring Load, Full Wind Plant Output, (Black=100% Type 3 Doubly Fed, Red=Mixed Technology, Green=100% Type 1 Induction Generator).

Dynamic Reactive Compensation Sensitivity Cases

While analyzing the baseline simulation results, it was observed that the Antelope and Vincent SVCs were not providing much reactive power to the system after fault clearing. Rather, the SVCs were providing reactive power during the fault and then again several seconds after the fault. Therefore, an evaluation of SVC response was also performed. The Vincent-Antelope 500 kV double line outage was applied to the light load system for this test. All wind plants were at full power output, with mixed WTG technologies in the new wind plants and Type 1 induction generator WTGs in the existing wind plants.

A comparison of system performance for three SVC scenarios is shown in Figure 5. The black line represents the baseline performance with the 200 MVAR Antelope and 600 MVAR Vincent 500 kV SVC model as provided, the red line represents performance with a modified dynamic SVC models at both locations, and the green line represents performance with neither SVC in service.

The modified dynamic model of the Antelope SVC provides more reactive power post-fault than the original model. As a result, the immediate post-fault voltage on the Antelope 500 kV bus is increased by about 2%. System response with both SVCs out of service is nearly identical to that with the original SVC model. The WECC voltage and frequency criteria were met, and the total loss of existing Type 1 induction generator wind plants was unchanged.

This analysis shows that the SVCs were not necessary to achieve acceptable performance with a likely mix of WTG technologies. If the SVCs are needed for other reasons, the dynamic models should be tuned to achieve better SVC response.

This analysis also shows that the SVCs were not sufficient to achieve acceptable performance with 100% Type 1 WTGs and no dynamic reactive capability in the new wind plants. This suggests that wind plants with some dynamic VAR capability will reduce or eliminate the need for dynamic reactive devices on the transmission system. Reactive power supplied close (e.g., at a wind plant substation) to where it is needed (e.g., at the Type 1 WTG terminals) will be more effective than reactive power at a remote location for the potential problems identified in this transient stability analysis.

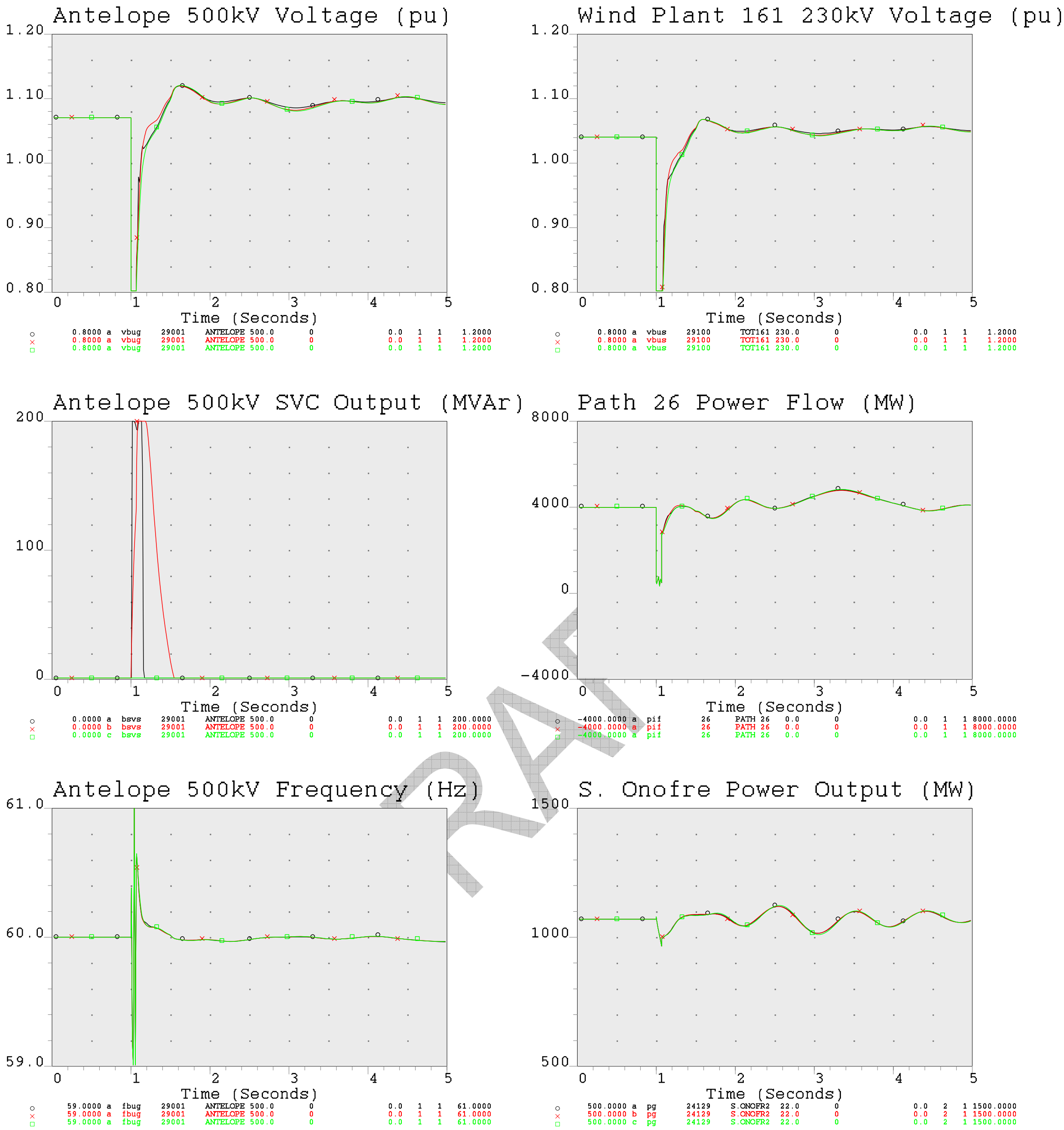


Figure 5. System Performance Overview, Vincent-Antelope 500 kV Double Line Outage, 2010 Heavy Summer Load, Full Wind Plant Output, Mixed Technology (Black=Nominal SVCs, Red=Modified SVCs, Green=No SVCs).

Post Transient Studies

Post-transient governor power flow studies were performed to evaluate the following:

- Post-transient voltage deviation analysis under three Tehachapi wind generation levels (i.e., full wind, low wind with 25% of name plate capacity, and no wind) for both the 2010 Heavy Summer load and the 2012 Light Spring load conditions;

- Voltage stability assessment through Q-V analysis to determine reactive margin at key bus voltages under various critical contingencies.

Post-Transient Voltage Deviation Analysis

Post transient governor power flow analyses were performed for the following 23 contingencies:

1. Palo Verde – Devers 500 kV single line outage;
2. Vincent – Rio Hondo 230 kV single line outage;
3. Sub. 5 (aka WhirlWind) – Midway 500 kV single line outage;
4. Vincent – Antelope 500 kV double line outage;
5. Lugo – Mira Loma 500 kV double line outage;
6. Vincent – Rio Hondo 230 kV double line outage;
7. Vincent – Mira Loma 500 kV single line outage;
8. Sub. 1 (aka Wind Hub) – Antelope 500 kV single line outage;
9. Vincent – Antelope 500 kV single line outage;
10. Vincent – Mesa 230 kV single line outage;
11. Diablo G-2 (two nuclear units) outage;
12. Vincent – North 500 kV double line outage (i.e., Vincent – Antelope & Vincent – Sub. 5 500 kV lines);
13. Vincent – Mesa 230 kV double line outage;
14. Lugo – Vincent 500 kV double line outage;
15. Sub. 1 – Sub. 5 500 kV single line outage;
16. Lugo – Vincent 500 kV single line outage;
17. Sub. 5 – South 500 kV double line outage (i.e., Sub. 5 – Antelope & Sub. 5 – Vincent 500 kV lines);
18. Midway – Vincent 500 kV double line outage (#1 & 2-500 kV lines);
19. Imperial Valley – Miguel 500 kV single line outage;
20. Intermountain Power Project DC (IPPDC) bi-polar outage;
21. Palo Verde G-2 (two nuclear units) outage;
22. Pacific DC Intertie (PDCI) bi-polar outage;

23. SONGS G -1-1 (one SONGS out of service initially, system readjusted, followed by the second unit outage);

Voltage Stability (Q-V) Analysis

Q-V analysis was performed for all critical twenty three contingencies to determine the following:

1. Whether the integration of 4200 MW wind generation meet applicable WECC planning standards by having positive reactive margin at key monitored buses under critical contingencies;

2. Whether the proposed reactive support provide satisfactory voltage performance (i.e., nose point voltage) under critical contingencies;

3. Whether additional analyses will be required to determine the optimal reactive support to meet the WECC voltage stability planning standards and to achieve better voltage performance (i.e., nose point) under Q-V analysis.

The buses monitored are located within PG&E and SCE systems near the Tehachapi wind farms: Midway 500 kV, Vincent 500 kV, Sub. 1 500 kV, Antelope 230 kV and Highwind 230 kV. In addition, major load bus such as Mira Loma 500 kV and major switching station such as Lugo 500 kV were also evaluated. To determine the available reactive margin at a specific bus, a fictitious synchronous condenser with a reactive range of ±3,000 MVAR[11] was modeled, with scheduled voltage reduced automatically, by using a program, in small increment until voltage collapse is expected. A system voltage is unstable if the bus voltage magnitude decreases as the reactive power injection is increased.

Following is the summary of the Q-V study results[12]:

1. The post-transient analysis study results indicate that the grid performance meet applicable WECC planning standards on voltage stability. Positive margin with adequate reactive margins at critical 500 and 230 kV buses were observed for critical contingencies, varying between 950 MVAR and more than 3000 MVAR for 500 kV buses and between 600 MVAR and 1,300 MVAR for 230 kV buses.

2. The Q-V plots from the heavy summer load scenario (below) indicate that the full-wind generation level corresponds to the least amount of available reactive margin. This condition is likely caused by high level of power transfer (approximately 6,300 MW) between the Tehachapi wind farms and imports from PG&E (via Path 26, which is the Midway-Vincent 500 kV intertie between PG&E and SCE systems), and the load centers in the L.A. Basin. On the other hand, with partial wind generation output (i.e., 25% of name plate capacity), the resultant reactive margin is better than the scenario where there is no wind generation. This indicates that better reactive margin performance, under the partial wind generation scenario, is contributed by the new wind turbines providing reactive support to the system under critical contingencies.

3. The Q-V analysis for the Heavy Summer load conditions indicate that the proposed transmission system to accommodate the additional new wind generation in the Tehachapi area may be highly compensated with the addition of new shunt capacitors. This is shown on the Q-V plots with high voltage nose point for various 500 kV buses under critical

[11] This range can be changed for higher value for the Q-V analysis. The higher range requires more computation time.

[12] The results shown for the SONGS G-1-1 as the critical contingency for the Heavy Summer load and Midway – Vincent 500kV double line outage for the Light Spring load conditions

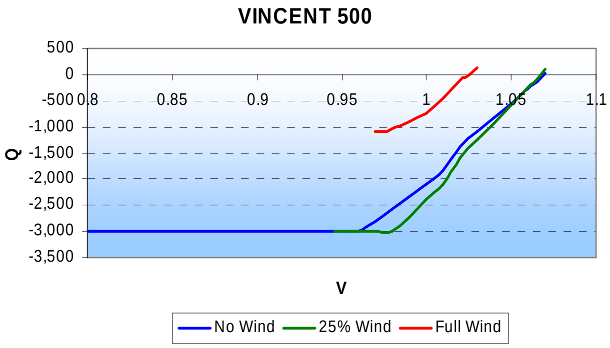
contingencies in the range of 0.95 – 1.0 p.u. voltage. Further analysis will be needed to optimize the additional reactive supports and to evaluate if series compensation would be required to help lower the voltage nose point in the Q-V analysis.

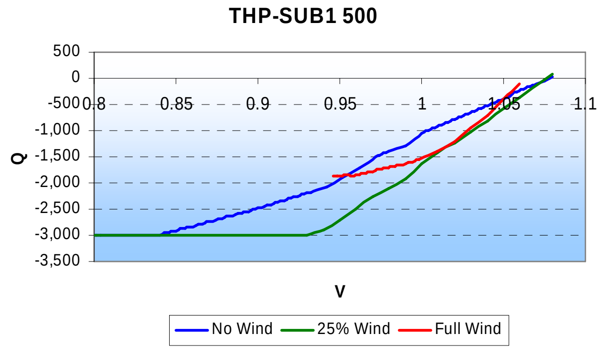
4. For the analysis of the Heavy Summer load conditions, the new wind farms in the Tehachapi area were studied with the assumptions that there would be no reactive consumptions at the wind plants. To accomplish this, the terminal voltage at the wind farms were scheduled higher (i.e., typical set point was 1.03 p.u. for many of these wind plants) to provide reactive support and to maintain power factor close to unity at its terminal voltage. If the plant's terminal voltage was inadvertently scheduled lower then it may trigger the plant to absorb reactive power. Consequently this will affect the Q-V analysis results as this may show higher voltage nose point due to the utilization of additional shunt capacitors at the point of interconnection to maintain at a minimum 0.95 power factor.

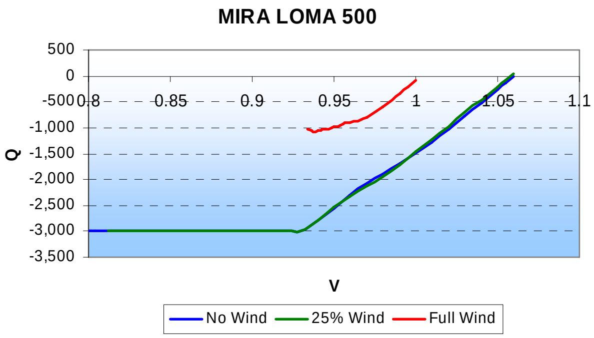
5. The study results for the Light Spring load scenario for three generation levels from the Tehachapi wind farms indicate that WECC voltage stability standards are met. The voltage performance is also satisfactory, with nose point below operating voltage. On some of the Q-V plots where the lines are flat out at -3,000 MVAR, the cause is due to the maximum set point at -3,000 MVAR for the fictitious synchronous condensers.

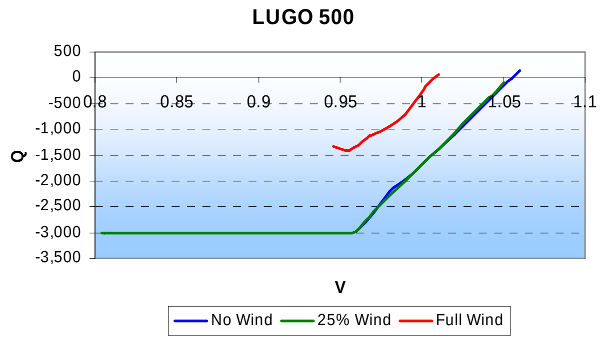
Post-Transient Voltage Stability Analysis

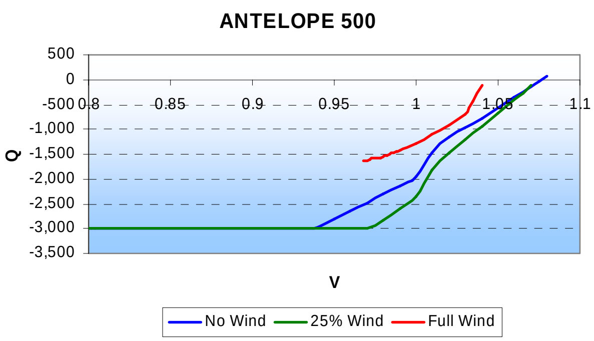
2010 Heavy Summer (G-2 -- Loss of Two Songs Units)

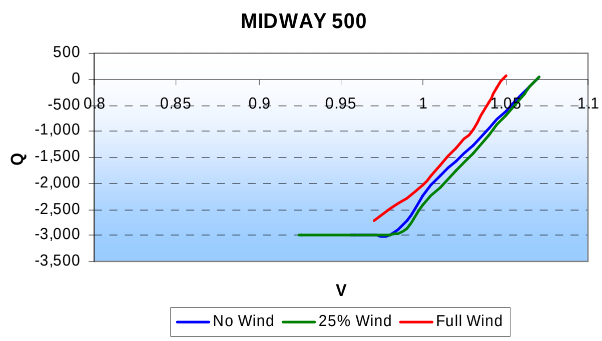


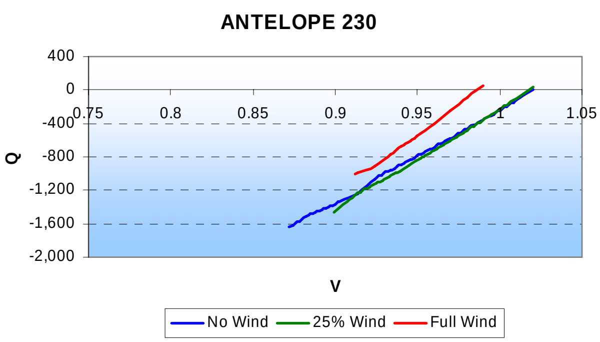


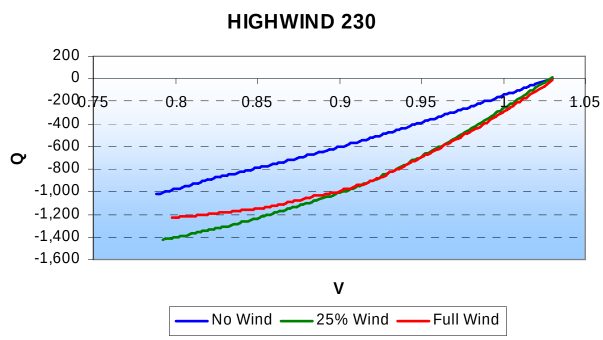






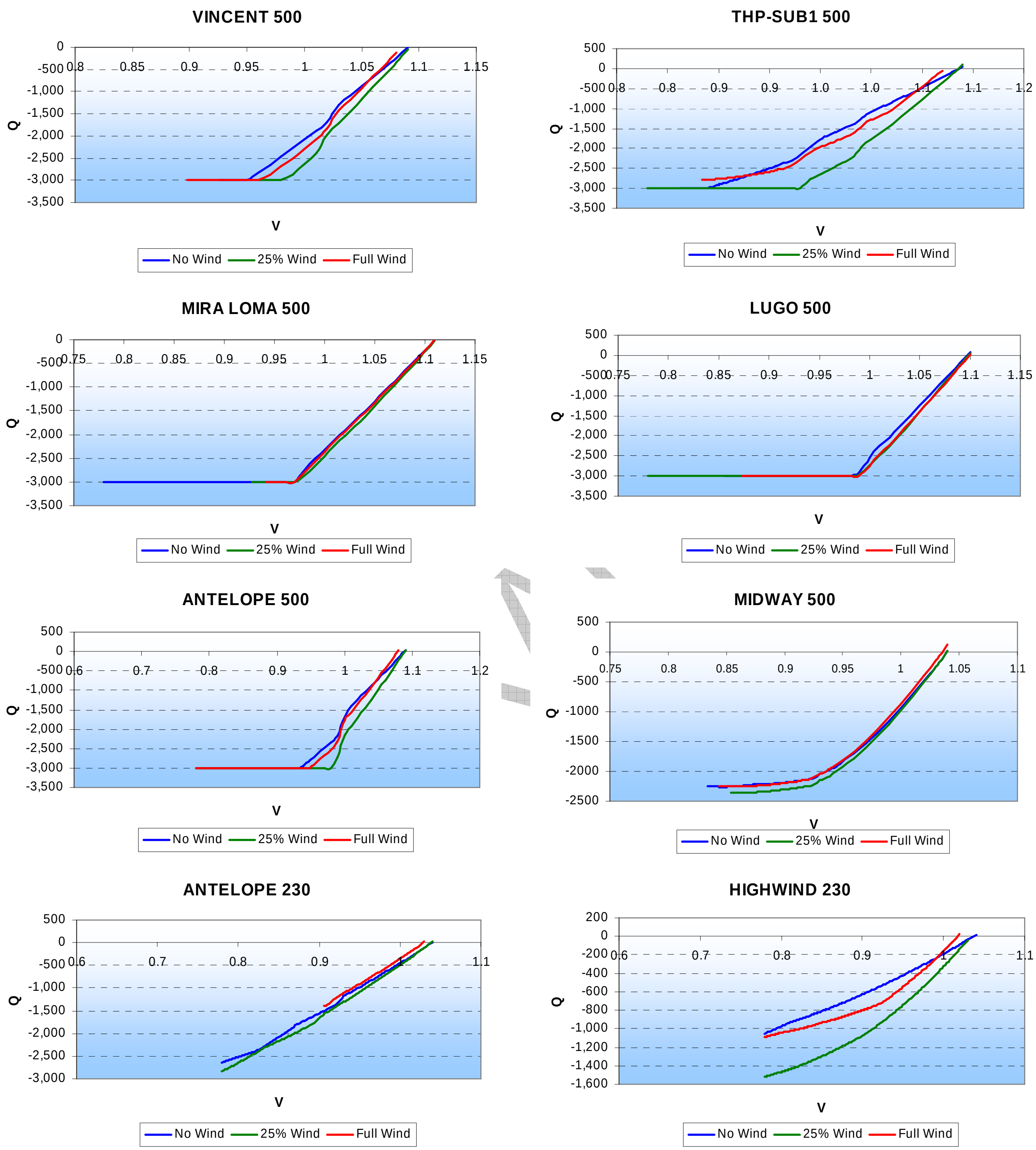






Note: The maximum set-point for the Q-V plots where set at -3000 MVAR.

Post-Transient Voltage Stability Analysis 2012 Light Spring (Midway-Vincent DLO)



Note: The maximum set-point for the Q-V plots where set at -3000 MVAR.

Generator Interconnection Standards

In the last two years, there has been a substantial increase of proposed renewable projects in the CAISO generator interconnection queue, mostly due to the RPS goals of California. The total renewable capacity in the queue almost doubled from 5,717 MW in January 2006 to 10,994 MW in January of 2007, and tripled in the first half of 2007 to 32,719 MW. History indicates that less than half of this capacity will actually come on line. Projects included in the queue represent both real projects with financing, site control, and purchase power agreements as well as speculative projects that many never come to fruition. Under FERC rules, these extreme differences in projects must be treated entirely the same. Moreover, if a project leaves the queue at any point in time, every project behind it requires complete restudy, which adds further complication and delays of interconnection.

To improve the legitimacy of the queue and increase the success rate, some changes to the FERC-mandated Large Generator Interconnection Process that should be considered, including:

- Require all applicants to prove absolute site control prior to being assigned a queue position.
- Only allow projects with commercial on line dates within 5 years (or other time frame) be allowed in the queue.
- Require higher deposits with LGIP applications and at each study phase.
- Force grouping/clustering of projects in same localized areas.
- Require strict valid technical data requirements with interconnection request.
- Require a third party to perform economic reality checks.
- Allow the ability to move projects forward in the LGIP study process that are proposed in known transmission rich areas and have no system impacts.
- Allow the CAISO tighter control of study timelines with possible penalties for PTOs/CAISO/Generators for missing deadlines.
- Remove the three year commercial online date (COD) extension option from the LGIP process or require system upgrade payments in accordance with original COD.
- Require wind developers to submit technical data per the LGIP, same as other developers. Currently FERC Order 661 allows wind developers to have 6 months to submit technical data. This impedes study progress on projects behind the wind project(s) in the queue.

It is understood that these proposed changes to LGIP would have to be developed through a formal stakeholder process and ultimately filed with FERC for approval, and this could prove to be a lengthy process. The length of this process will likely be less if the CPUC and other state agencies participate in this process and support these reforms.

WECC Low Voltage Ride Through Standard (LVRT)

The WECC Wind Generation Task Force (WTF) published a White Paper on May 22, 2007 the proposed WECC LVRT Standard. The paper, “The Technical Basis for the New WECC Voltage Ride-Through (VRT) Standard”, proposes to bring the WECC LVRT standard in-line with FERC

Order No. 661-A which specifies the unit must be able to handle zero volts for 9 cycles. The goal is to modify the existing WECC LVRT Standard that was approved by the WECC Board in April 2006. The paper presents arguments for numerous requirements that should be improved in the new proposed standard.

Chapter 4 – Forecasting Issues

4.1. Market Operations – Day-Ahead Timeframe

The CAISO Day-Ahead load forecast is calculated by utilizing neural-network forecasting software. Multiple weather forecasting data sources are used to determine the weather forecast. To ensure the average load forecasting error is minimized, the CAISO continuously monitors and revise its weather forecast and subsequently it's Load Forecast. Load Serving Entities (LSEs) also forecast their hourly load demand, which they use to schedule energy demand in the CAISO's DA market. Like all forecast, there are scheduling errors associated with the LSEs DA scheduled Load and the actual load. In addition to the CAISO Load forecasting errors and LSEs scheduling errors, uncertainties are also introduced in the DA scheduling process because intermittent resources are not required to submit DA schedules.

Currently, uncertainty associated with forecasting the output levels of intermittent resources in the DA timeframe do not pose any reliability concerns because the actual wind generation output is typically less than 1,100 MW. As shown in Figure 1, by 2010 wind generation may peak as high as 6,000 MW and production levels could exceed 2,000 MW for approximately 50% of the year. A lack of Day-Ahead forecast for amount of wind generation could result in significant reliability issue. (?? There are a series of Figures references and Figures without numbers in this chapter.)

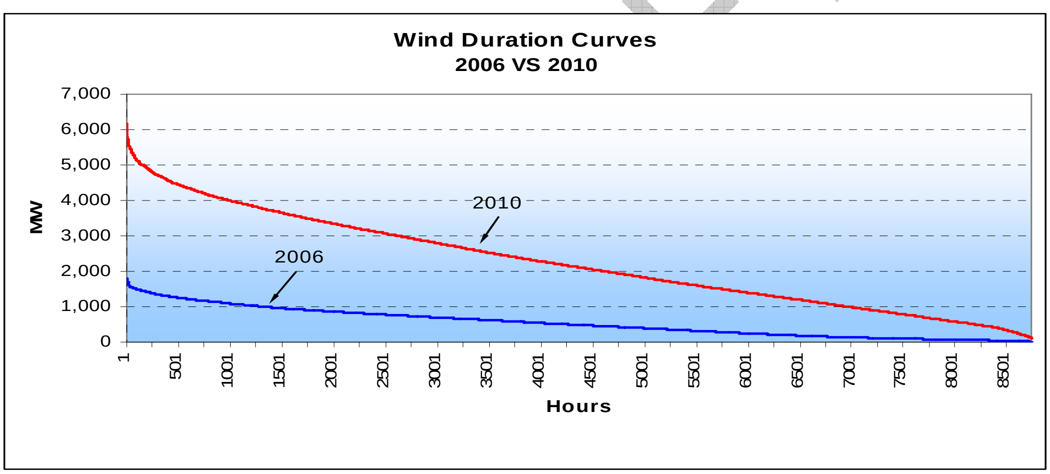


Figure 1: Actual Wind Generation for 2006 vs. Expected Wind Generation for 2010

As more and more intermittent resources become operational, the existing uncertainties and operational challenges in the DA timeframe are expected to get worst. The risk associated with the expected uncertainties in the DA timeframe could result in insufficient resources committed through the Residual Unit Commitment (RUC) Process to meet next day hourly demand.

These challenges are expected to get worst with a total of 6,688 MW of intermittent resources to meet the 20% RPS requirement.

4.2. CAISO Day-Ahead Load Forecast

The CAISO utilizes an Automated Load Forecasting System (ALFS) to calculate its Day-Ahead (DA) Hourly Forecasted Demand approximately 14 hours prior to the next operating day. As shown in

Figure 2 for 2006 approximately 10% of the DA hourly forecasting error was greater than 1,000 MW and similarly, approximately 10 % of the time the forecasting error was less than 1,000 MW. For the hours when the Load Forecast is deficient, the CAISO makes up this difference by committing resources through its Real Time Unit Commitment process.

If the scheduled CAISO Demand exceeds the CAISO Forecast, the RUC process may identify the need to de-commit resources but the RUC process does not automatically de-commit a resource scheduled in the Integrated Forward Market. The CAISO Operator may communicate the need for de-commitment of resources with affected Market Participants if the scheduled CAISO Demand exceeds the CAISO Forecast during the Hour Ahead Scheduling Process (HASP).

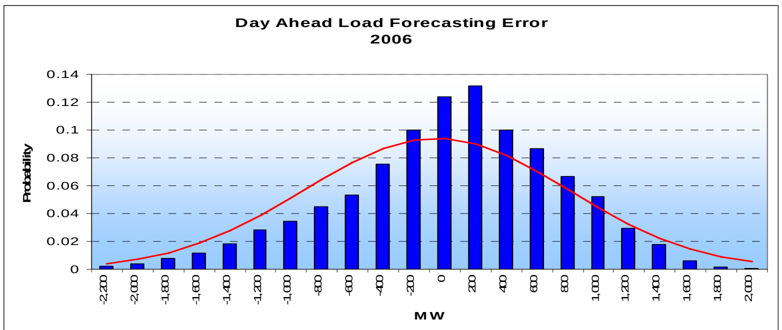


Figure 2: CAISO DA Load Forecasting Error

4.3. Day-Ahead Scheduling Process

Load Serving Entities (LSEs) schedule energy (including the 20-minute ramps between hours) in the DA timeframe to meet their forecasted load as block energy schedules. The Day-Ahead market closes at 1000 hours and results published by 1300 hours the day preceding the operating day. The DA scheduling errors based on the 2006 summer months averages approximately 355 MW higher than the actual load. As shown in Figure 3, the hourly scheduling error mimics a normal truncated distribution curve with a standard deviation of approximately 1,700 MW. In the DA timeframe, for summer 2006 there was a probability of 8% that the scheduling errors were less than 2,000 MW and a probability of19% that it was greater than 2,000 MW. This scheduling error is assumed to be about the same for the 2010 timeframe. The under-scheduling difference is procured through the CAISO's Residual Unit Commitment (RUC) process and takes into consideration Load forecasting errors and estimated generation output from Wind Resources. As stated above, forecasting the wind generation in the DA does not pose a reliability concern today, however forecasting wind generation in the 2010 timeframe is crucial in committing non-wind resources in the DA timeframe.

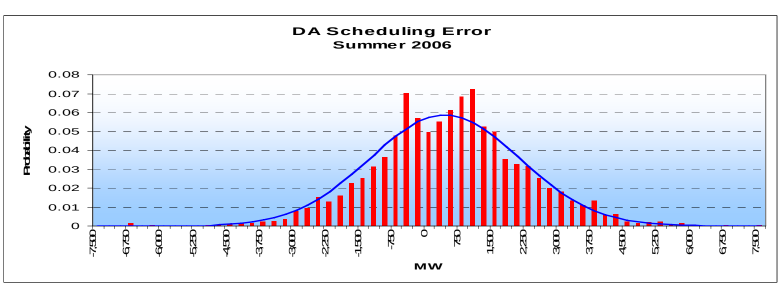


Figure 3: Day-Ahead Load Scheduling Error

4.4. Wind Resource Forecasting

Wind Resources are not required to bid or schedule in the CAISO Day-Ahead Market. However, when bids are scheduled in the DA Market, the ultimate quantity scheduled from the Wind Resource differ from the CAISO forecasted deliveries from the Wind Resource. The CAISO uses a neural-network forecasting service/software to forecast deliveries from Wind Resources based on the relevant forecasted weather parameters that affect the output of the Wind Resource. The CAISO monitors and tunes forecasting parameters on an ongoing basis to reduce intermittent forecasting error.

4.5. Residual Unit Commitment (RUC)

The CAISO adjust the hourly generation forecast either up or down for the expected wind generation. To the extent the scheduled quantity for a Wind Resource in the DA is less then the quantity forecasted by the CAISO, the CAISO makes a Supply side adjustment in RUC by using the CAISO forecasted quantity for the Wind Resource as the expected delivered quantity. To the extent the scheduled quantity for a Wind Resource is greater than the quantity forecasted by the CAISO, the CAISO makes a Demand side adjustment equal to the difference between the Day-Ahead Schedule and the CAISO forecasted quantity.

As more and more wind resources are installed, estimating the total wind output in the Day-Ahead timeframe creates a challenge. One of the tasks addressed in Chapter 10 of this Report under implementation is the competitive procurement of a Day-Ahead Wind Generation Forecasting Service that can provide the CAISO with an accurate DA wind generation forecast.

4.6. Hour-Ahead Energy Forecast for Wind Generators

The CAISO currently uses an outside service to forecast the Hour-Ahead energy production from wind generation facilities that are in the Participating Intermittent Resources Program (PIRP). The amount of wind generation in PIRP is 685 MW which is about 25% of the total wind generation installed on the system. The CAISO contract with the Forecasting Service Provider is to provide hourly wind generation energy forecast that have a monthly deviation of less than 12%. The hourly forecast are actually created nearly 3 hours before the actual operating hour so the forecast data can be used to schedule the energy in the existing Hour-Ahead market.

MRTU will shorten the PIRP scheduling process to 75 minutes before the operating hour. This should result in greater accuracy for the hour-ahead forecasts and schedules. Changes in the forecast methodology and the structure of the PIRP program are being considered as a task to be implemented under Chapter 10 of this Report.

An issue paper is also being developed to integrate solar (PV and Concentrated) into PIRP. The goal is to have the solar integration policy completed by January 2008.

Chapter 5 - Operations Issues

5.1. Impacts of Wind Generation on CAISO's Ramping, Regulation and Load Following Requirements Under MRTU

This chapter of the report primarily focuses on wind resources to meet California RPS goal of 20% renewable in its generation mix by 2010. Small hydro, biomass, and geothermal generation are very predictable resources and their integration into the CAISO market and production levels are not anticipated to cause any operational problems. Also, it is not anticipated that any significant solar resource additions would be completed by the 2010 timeframe, thus no integration issues are envisioned. However, the integration of large amounts of wind resources into the CAISO generation mix is expected to create operating challenges because wind production is a function of wind speed and it is not dispatchable.

Wind generation output varies significantly during the course of any given day and there is no predictable day-to-day generation pattern. One major challenge to system operators is the availability and accuracy of Day-Ahead and Hour-Ahead wind generation forecast to ensure sufficient units are committed in the Day-Ahead and Real Time markets for the next operating day. The CAISO also anticipates facing daily challenges to ensure adequate non-intermittent resources are available to meet multi-hour ramps, to accommodate changes in system load and wind generation. These challenges are compounded when combined with large hourly ramp changes on the interties and hourly generation scheduling changes. The following analysis investigates the overall system performance under the CAISO Market Redesign Technology Upgrade (MRTU) design and operating timelines.

The installed wind capacity in the five existing wind parks located within the CAISO operational jurisdiction is approximately 2,648 MW (Solano - 327 MW, Altamont - 954 MW, Pecheco - 21 MW, Tehachapi - 722 MW, and San Gorgonio - 624 MW). Although the CAISO interconnection queue for renewable resources through the year 2013 contains in excess of 14,000 MW of wind resources, this study only assumes an additional 3,540 MW would be installed in the Tehachapi area and an additional 500 MW would be installed in the Solano wind park for an overall total of 6,688 MW of wind generation. Major transmission upgrades must be built to accommodate these generation additions. These required transmission upgrades have already been approved by the CAISO Board of Governors and the respective Participating Transmission Owners.

Assumptions

Determining the expected ramping, load following and regulation requirement for the 2010 timeframe is a function of statistical minute-to-minute actual wind generation and the determination of statistical errors associated with the CAISO load and wind forecasting methodologies in the Day-Ahead, Hour-Ahead and Real Time timeframes. The major data sources and study assumptions are as follows:

1. The 2010 hourly wind production data was developed by AWS Truewind. The minute-to-minute variability was developed by the CAISO and AWS Truewind. The methodology used is outlined in Appendix D.

2. The overall load increase is consistent with the CEC's forecasted energy growth for the state and is assumed to be 1.5% per year from 2007 through 2010 for the CAISO operational jurisdiction.

3. The energy produced by wind resources varies as a function of wind speed.

4. Impacts of wind generation on the interconnection frequency are neglected.

5. All new wind generation additions within the CAISO operating jurisdiction will participate in the PIRP program, and therefore they will be provided with a centralized Day-Ahead and Hour-Ahead forecast service.

6. The Hour-Ahead load and wind generation energy forecasts are provided at latest 120 minutes before the beginning of the next operating hour.

7. The Real Time five-minute load forecasts are provided 7.5 minutes before the actual beginning of a five-minute dispatch interval (or 10 minutes before the middle point of this interval).

8. Real Time telemetry from the wind resources are sent to the CAISO on a four-second basis similar to non-intermittent resources.

9. Pump storage **is not** considered as a part of the actual load and the load forecast. It is considered as a scheduled resource. The impact of small pumps is included in system load so they are not scheduled.

Study Methodology

The methodology developed to analyze the wind generation impact is based on a mathematical model of the actual CAISO's scheduling, Real Time dispatch, and regulation processes and their timelines. Minute-to-minute variations and statistical interactions of the system parameters involved in these processes are depicted with sufficient details to provide a robust and accurate assessment of the additional capacity, ramping and ramp duration requirements that the CAISO regulation (AGC) and load following (ADS) systems will be facing in the year 2010.

In order to represent the CAISO's Hour-Ahead scheduling process, the probability distributions of the total CAISO load forecast and total CAISO wind generation forecast errors[13] were studied for the year 2006. Refer to Appendices C & E. It has been found that these errors have a close normal probability distribution with negligible average forecast error and significant autocorrelation between the subsequent forecasts. The wind generation forecast statistical parameters were discussed with and approved by AWS Truewind Company for each season of a year. A special truncated normal distribution random generator with controllable standard deviation and autocorrelation was designed to simulate the sequences of random forecast errors for each study season. The Hour-Ahead schedules for the system load and wind generation were created for each operating hour based on the actual predicted load and wind generation curves as well as the simulated Hour-Ahead forecast errors. Twenty-minute ramps were added between the subsequent operating hours.

[13] An assumption was that a comprehensive Hour-Ahead wind generation forecast would be available for the CAISO, Scheduling Coordinators and IOUs and that it would be incorporated in the Hour-Ahead scheduling processes. It is expected that the new wind generation projects in California will participate in the CAISO PIRP program where the Hour-Ahead forecast would be available as a PIRP requirement.

In order to simulate the Real Time dispatch process, the Real Time load forecast error was also analyzed and simulated similarly to the Hour-Ahead load forecast. The randomly generated error was subtracted from the actual five-minute averages of the system load to simulate the Real Time load schedules. Five-minute ramps were added to the simulated load schedule curves. The Real Time wind generation curves were modeled by applying the persistence model. This model assumed that the wind generation within each five-minute dispatch interval would be the same as it was eight minutes before the beginning of this interval[14].

The load-only impact on regulation was considered as the minute-to-minute difference between the simulated Real Time load schedule and the actual load.

The wind generation impact on regulation was simulated in three steps. First, the difference between the actual wind generation and the simulated wind generation schedule was evaluated for every minute. Second, the combine impact of the system load and wind generation on regulation was simulated as the difference between the load-only impact curve and wind generation impact curve. This approach fully depicts the statistical interactions between the load and wind generation unscheduled changes. Third, the additional impact of wind was calculated as the difference between the combine impact and load-only impact.

The load-only and combined load and wind generation impact curves were analyzed using the swinging door algorithm[15] to calculate the ramp and ramp duration requirements for each minute in the study season. Please refer to Appendix A for a detail description of the algorithm.

Conclusions

1. Integrating 20% renewables in the CAISO Control Area is operationally feasible, however several additions to the operational practice will be required – see Recommendations. Without these recommended changes, there may be significant impacts on the market clearing prices and unit commitment costs.

2. The 20% renewables requirement is expected to increase the three-hour morning ramp by 926 MW to 1529 MW and the three-hour evening ramp by 427 MW to 984 MW depending on the season.

Seasons	*2006 Morning Ramps MW*	*Expected 2010 Morning Ramps MW*	*Expected Change due to Intermittency MW*	*2006 Evening Ramps MW*	*Expected 2010 Evening Ramps MW*	*Expected Change due to Intermittency MW*
Spring	6,860	8,494	955	7,962	9,788	984
Summer	10,090	12,664	1,529	10,589	12,135	427
Fall	7,229	8,995	1,023	11,511	13,483	740
Winter	6,979	8,631	926	7,856	9,293	603

Table 1: Summary of Multi-Hour Ramps

3. The CAISO regulation capacity requirements will increase noticeably during certain hour ranges. The increase is explained by increasing inaccuracy of the persistence model used in this study for the Real Time wind generation forecast, which reflects the current approach

[14] This means that the real time wind generation forecast is not available.

[15] The swinging door algorithm helped to build a meaningful sequence of ramps needed to provide an adequate regulation service. The algorithm is based on a user-specified tolerance of following the ramps.

used by the CAISO's Real Time Dispatch. The following table summarizes the study results (maximum expected values) based on Hour-Ahead wind generation forecasting error of 7% to 9% depending on the season. Regulation capacity requirements decrease with better wind forecast.

Season	Max Regulation Up, MW	Max Regulation Down, MW	Max Hourly Increase (Up), MW	Max Hourly Increase (Down), MW
Spring	+510	-550	+240 (HE18)	-300 (HE18)
Summer	+480	-750	+230 (HE09)	-500 (HE18)
Fall	+400	-525	+170 (HE06, HE18)	-275 (HE18)
Winter	+475	-370	+250 (HE18)	-100 (HE10)

4. The CAISO regulation ramping requirements in 2010 is expected to increase by about ±10 to ±25 MW/min. These increases will affect AGC ramps up to five-minutes long.

Seasons	***Max Increase Regulation Ramp Up, MW/min***	***Max Increase Regulation Ramp Down, MW/min***
Spring	+20	-25
Summer	+10	-18
Fall	+25	-20
Winter	+15	-15

5. The CAISO would also require a significant increase in the supplemental energy stack to meet intra-hour load following needs. The increase is explained by the fact that the Hour-Ahead wind generation forecast error (standard deviation is evaluated as 7-9% of the total installed wind generation capacity) becomes comparable with the Hour-Ahead load forecast error (standard deviation is 600-900 MW). These load following capacity requirements decrease with better wind forecast. Please refer to Table 5 for a comparison of load following capacity requirements when a 5% wind forecasting error is used.

Season	Max Load Following Inc, MW	Max Load Following Dec, MW	Max Hourly Increase (Inc), MW	Max Hourly Increase (Dec), MW
Spring	+2,850	-3,000	+800	-500
Summer	+3,470	-3,430	+800	-600
Fall	+3,080	-3,200	+750	-900
Winter	+2,550	-3,050	+700	-750

6. The CAISO maximum load following ramping requirements in 2010 is expected to increase by about ±30 to ±40 MW/min. These increases will affect ADS ramps up to 20-30 minutes long.

Season	Max Load Following Ramp Up, MW/min	Max Load Following Ramp Down, MW/min
Spring	+35	-30
Summer	+40	-40
Fall	+40	-30
Winter	+30	-40

Recommendations

1. Implement a state-of-the-art wind forecasting service for all wind generator energy production within the CAISO operational jurisdiction. This includes Day-Ahead, Hour-Ahead, and Real Time wind generation forecasts. These forecasts will be crucial for the unit commitment, scheduling, and dispatch processes in the Day-Ahead, Hour-Ahead and Real Time timeframes.

2. Incorporate the Day and Hour-Ahead wind generation forecasts (block energy schedules) into the CAISO's and SC's scheduling processes. The Day and Hour-Ahead schedules must be based on the forecasted wind generation values.

3. Integrate the Real Time wind generation forecast (average wind generation for 5-minute dispatch intervals) with the Real Time unit commitment and MRTU dispatching applications.

4. Develop a new ramp forecasting tool to help system operators anticipate large energy ramps, both up and down, on the system. The longer the lead time for forecasting a large ramp, the more options the operators have to mitigate the impact of the ramp. One of the proposed tasks under Chapter 10 of this Report will address the creation of the ramp forecasting tool.

5. Change the ISO generator interconnection standards to require compliance of all intermittent resources with the interconnection rules established for the Participating Intermittent Resources program. These rules include installing meteorological towers and DPG telemetry systems to communicate the 4-second data meteorological and production data from wind parks to the CAISO. This data needs to be integrated into the CAISO's forecasting software.

6. Implement a procedure where the CAISO Dispatcher can send dispatch notices to wind generation operators and require them to implement pro-rata cuts in their energy production. During over generation periods, when dispatchable generation plants are already operating at their minimum levels, the CAISO needs to have an ability to curtail wind generation on an as needed basis.

7. Analyze the impact of solar power intermittency with load and wind generation intermittency.

8. Evaluate technological changes that can facilitate the integration of large amounts of intermittent resources. For example, evaluate the benefits of participating in a wider-area arrangement like ACE sharing or Wide Area Energy Management system[16].

9. Study the impact that additional cycling (additional start ups) and associated wearing-and-tearing issues, dispatches below the maximum unit capacity and associated additional costs and environmental impacts on conventional generation due to the integration of large amounts of intermittent resources. Address if improvements can be made to the CAISO's Scheduling, Real Time Dispatch, and Regulation systems that will minimize the impacts on conventional units?

10. Encourage the development of new energy storage technology that facilitates the storage of off peak wind generation energy for delivery during on-peak periods.

11. Include changes in Resource Adequacy standard to require more generation with faster and more durable ramping capabilities that will be required to meet future ramp requirements[17].

12. Include changes in Resource Adequacy standard to require additional quick start units that will be required to accommodate Hour-Ahead forecasting errors and intra-hour wind variations.

[16] Principles of the Wide Area Energy Management system are currently under design at PNNL. The project is sponsored by BPA. The CAISO is a participant in this project.

[17] The CAISO is currently participating in a CEC-sponsored project with PNNL and ORNL on the value of fast regulation resources.

Day-Ahead Forecasting and Scheduling Process

Day-Ahead (DA) load forecast errors coupled with DA wind generation forecast errors can have a significant impact on the Residual Unit Commitment process. This problem could get worst due to the fact that wind resources are not required to bid in the DA market.

Day-Ahead Load Forecast

The Day-Ahead hourly load forecast is calculated approximately 14 hours before the start of the operating day. Based on 2006 data, the Day-Ahead forecasting errors can vary from ± 3,000 MW with a standard deviation of 858 MW.

With the exception of pump loads which are scheduled, the CAISO peak load demand is proportional to temperature. Historical load and temperature data for several weather stations within the CAISO operational jurisdiction is shown in Figure 1. As the CAISO average temperature exceeds 100 ^oF, the load forecast varies significantly for each degree change in average temperature. When the average temperature is above 100 ^oF, a forecasting error of one degree could result in the CAISO load forecast potentially being understated or overstated by approximately 980 MW (Southern California Edison 490 MW/^oF; Pacific Gas & Electric 399 MW/^oF and San Diego Gas & Electric 91 MW/^oF.)

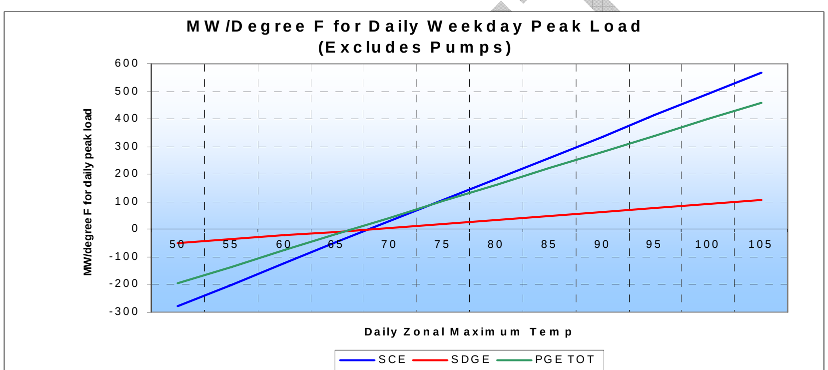


Figure 1: Temperature vs. Peak Load Variation

Wind Generation Day-Ahead Forecast and Schedules

Wind Resources are not required to bid or schedule in the CAISO Day-Ahead Market (DAM). However, when bids are scheduled in the DAM, the quantity scheduled typically differs from the CAISO forecasted deliveries. In the 2010 timeframe, with the installed capacity of wind generation at about 6,688 MW, the DAM could clear at significantly lower levels for next day operation based on self schedules and economic bids from Scheduling Coordinators, which may or may not include wind generation forecast.

To minimize DA forecasting errors, the CAISO is preparing a bid specification for procurement of a Day-Ahead wind generation forecasting service. An RFP is slated to be released this fall of 2007 and a service provider chosen by the end of the year.

Day-Ahead Market

Bidding into the Day-Ahead Market (DAM) is closed at 1000 hours and results are published by 1300 hours on the day preceding the operating day. Scheduling Coordinators (SCs) submit Bids (for

Supply and Demand) for each resource to be used in the DAM. Ancillary Service (AS) Bids are also submitted in the DAM, which is optimized in conjunction with Energy Bids to minimize the total Bid Cost of clearing Congestion, balancing Energy Supply and Demand, and reserving AS. Also, in the DAM, the CAISO runs a Residual Unit Commitment Program (RUC) to ensure that sufficient capacity is committed, on-line and available for dispatch in Real Time to meet the CAISO forecast of CAISO demand for each Trading Hour of the operating day.

While RUC commits resource capacity from Long Start and Short Start Units to meet CAISO forecast of demand, RUC does not automatically de-commit resources in cases where the DA Schedules exceed the load forecast. When more generation is anticipated than load, exceptional dispatches may be necessary to resolve over generation conditions. Such actions may require de-committing resource. Should over-generation conditions propagate into Real Time and dispatchable generators are already operating at their minimum levels, the CAISO needs to have the ability to curtail wind generation, as necessary, to maintain reliability.

Wind vs. Actual Load on a Typical Hot Day

Typically during the summer, wind generation peaks when the total system load is low and is at its lowest production levels when the total system load is high. Figure 2, shows the variation of average hourly wind generation and the actual wind generation (red dots) at the time of the daily system peak load during the week with the hottest average temperatures within the CAISO operational jurisdiction in 2006.

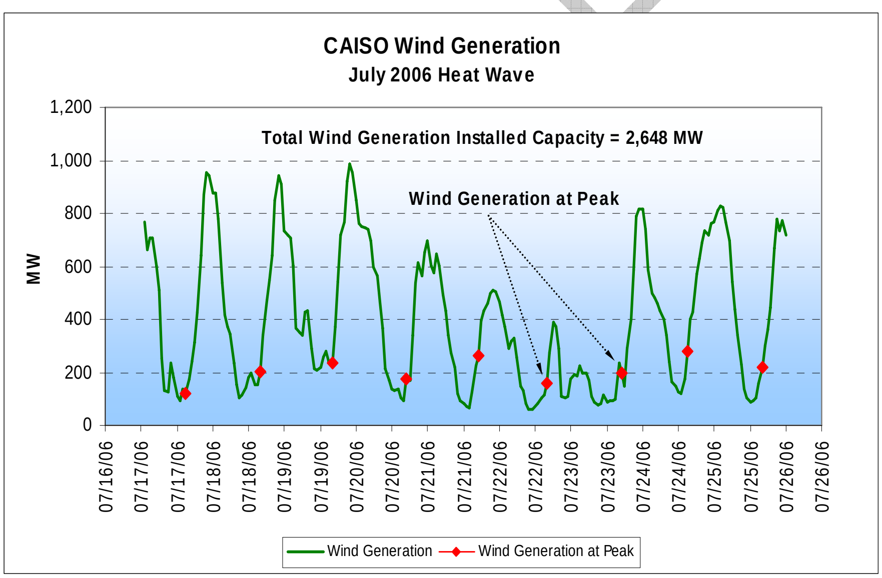


Figure 2: CAISO Wind Generation during the 2006 Heat Wave

Although the daily summer pattern "high load and low wind" is predictable, the actual hourly wind generation output can vary significantly from one day to the next. Figure 3 shows the actual wind generation for May 2006 compared to the expected wind generation in 2010. As shown, the hourly generation varied significantly in 2006 and without dependable wind generation forecast, it's difficult to predict the expected wind generation in any given hour. For example, in 2010 for HE19, the wind generation is expected to vary between 1,400 MW and 6,000 MW.

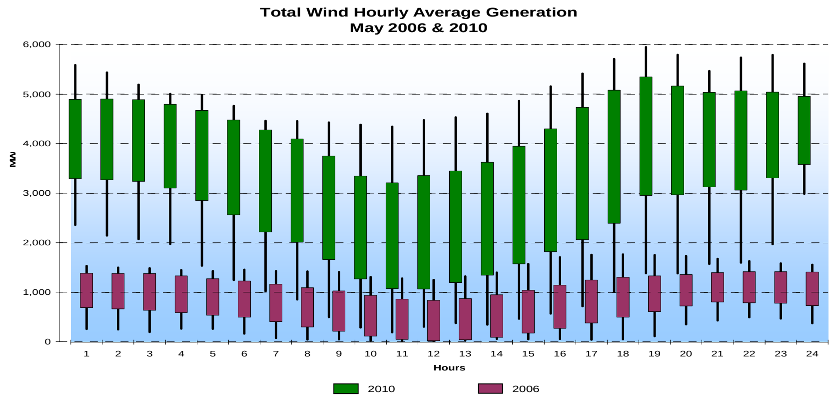


Figure 3: Actual 2006 Hourly Wind Generation vs. Expected 2010 Hourly Wind Generation

Note: The colored bars represent one standard deviation from the mean. The top of each vertical line shows the hourly maximum and the bottom shows the minimum expected generation for that hour.

Multi-Hour Seasonal Ramping Requirement

With an expected installed wind generating capacity of 6,688 MW, the minute-to-minute and hourly variability on the system is expected to increase. Both the CAISO load demand and wind generation characteristics vary by season. In 2005 and 2006, the maximum wind production occurred in late spring (May) followed by the first month of the summer (June). In 2010, a combination of load increase in the morning hours and a decrease in wind production during Hour Ending (HE) 8 through HE10 in the summer months could result in the need to commit about 12,664 MW of capacity in the Day-Ahead Market or have adequate Short Start and Fast Start resourced available to commit in Real Time. Similarly, a combination of load drop-off in the evening hours and an increase in wind production during HE22 through HE24 could result in the need to curtail about 13,500 MW of generation over a three-hour period.

Spring Months

During the spring months (March, April and May), the CAISO load characteristic has a unique shape that shows two daily peaks, one occurring around HE13 and the second around HE21. Figure 4 shows the average hourly system load, average wind generation and solar generation during the course of a typical day. As shown, the total wind generation starts decreasing after midnight and reaches its minimum production level around midday, just as the system experiences the first peak of the day. Beginning around HE13, the wind generation starts ramping up while system load typically drops off.

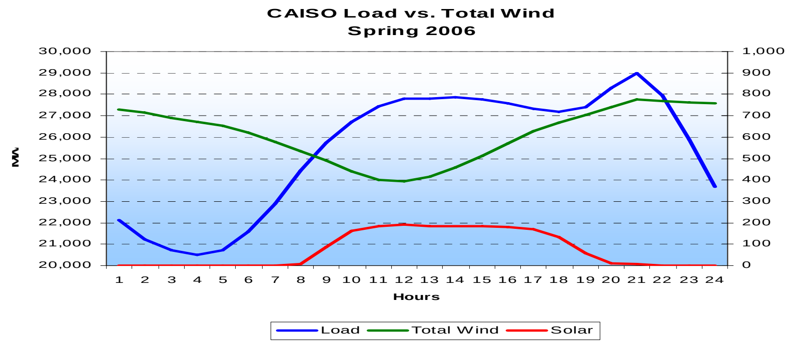


Figure 4: Actual System Load, Wind Generation and Solar Generation for Spring 2006)

As system load increases towards the second peak of the day, wind generation helps in offsetting some of the energy required to meet the increase in load. As system load begins dropping after the peak of the day, wind generation is typically at its highest generation level. During the 2006 spring months, the average hourly wind generation peaked at about 775 MW. In 2010, the wind generation is expected to peak around 5,950 MW.

As shown in Figure 5 below, the maximum hourly deviations occurred during HE19 and varied from -225 MW to 340 MW. In 2010, the actual generation level is expected to vary between 125 MW and 5,950 MW. The largest hourly deviation is still expected to occur during HE19 and can vary from -1,150 MW to 1,480 MW, which coincides with the system load increase and the increase in wind generation.

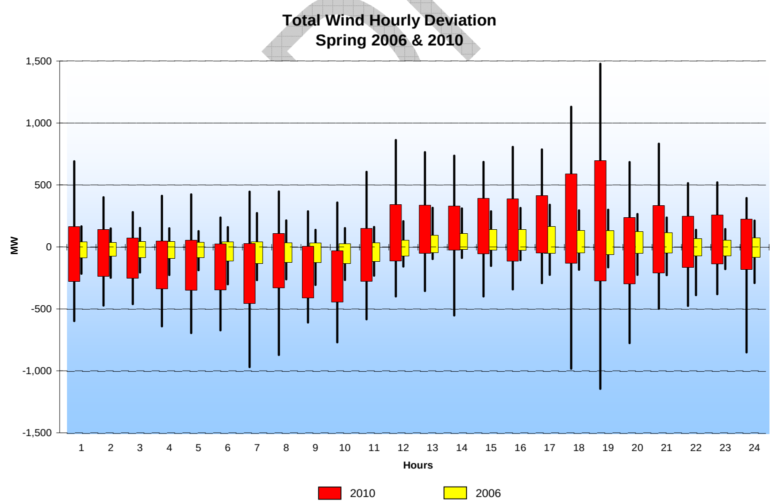


Figure 5: Spring 2006 Actual Hourly Variations vs. Expected 2010 Hourly Deviation

Note: The colored bars represent one standard deviation from the mean. The top of each vertical line shows the hourly maximum and the bottom shows the minimum generation for that hour.

Spring - Morning and Evening Multi-Hour Ramps

During the 2006 spring months, the maximum morning load buildup from HE7 through HE9 was approximately 6,170 MW while the maximum wind generation decreased by approximately 690 MW. Figure 6, shows the maximum increase/decrease for each of the hours in the three-hour ramps. It is expected that by the 2010 timeframe, the morning load buildup would increase to approximately 6,847 MW. During this same three-hour window, wind generation is expected to decrease by about 1,646 MW, which would result in the need to increase generation by approximately 8,493 MW. This additional increase in resources would have to be committed in either the Day-Ahead Unit Commitment process or through the Real Time Unit Commitment process. Any deficiency would have to be met through Load Following and Regulation.

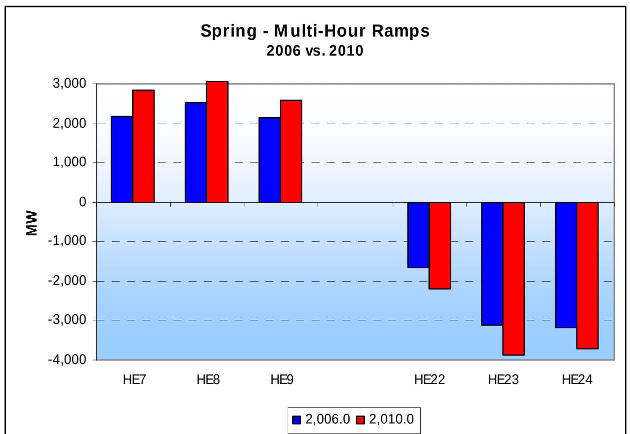


Figure 6: Actual Net Hourly Ramps

During the evening hours (HE22 through HE24), the system load typically decreases while wind generation is at its highest of the day. In 2006, the maximum reduction in load was about 7,660 MW while the maximum increase in wind generation was about 301 MW. It is expected that by the 2010 timeframe, the total system load would decrease by about 8,502 MW during these three hours and wind generation could increase by about 1,286 MW. These changes in load and wind generation could require decreasing non-wind resources by about 9,788 MW.

Summer Months

The CAISO load typically peaks during the summer months (June, July and August). Likewise, the highest production level from wind generation is also at the highest during the summer months. Unfortunately, the highest load demand periods coincide with low levels of wind production and low levels of load demand coincides with maximum levels of wind production.

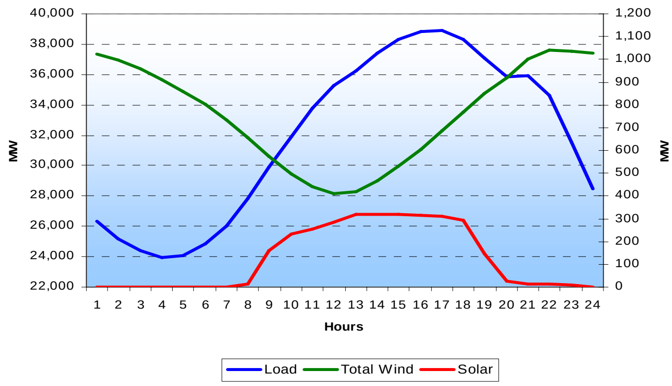


Figure 7: Actual System Load, Wind Generation & Solar Generation for Summer 2006

As shown in Figure 7, the maximum load variations are more noticeable during the summer months. The daily load cycle reaches a minimum around HE4 and peaks around HE17. After the peak demand of the day is realized, load gradually decreases while wind production continues to increase up to about HE22 and remains more or less constant through midnight. After midnight wind production gradually decreases and reaches its lowest level of production around midday. Although small in capacity, solar generation profile coincided with that of load and could be beneficial in alleviating some of the expected ramping concerns as more of California's RPS goals are met with the integration of solar resources.

During the 2006 summer months, maximum wind generation occurred between HE20 through HE24 and averaged about 1,100 MW while the minimum levels occurred around midday and averaged approximately 400 MW. This pattern is expected to continue in the 2010 timeframe. In 2010, it is expected that the hourly variations would be between -1,140 MW and 1,820 MW with a standard deviation of approximately 390 MW.

Summer - Morning and Evening Multi-Hour Ramps

During the 2006 summer months, the maximum morning load buildup (HE8 through HE10) increased by approximately 9,509 MW while the maximum reduction in wind production was approximately 582 MW, an overall increase of about 10,091 MW. Figure 8 below, shows the net average increase for each operating hour within the three hour ramps. It is expected that by the 2010 timeframe, the maximum morning load buildup could increase to approximately 10,553 MW while wind generation is expected to decrease by about 2,111 MW for a net increase of approximately 12,664 MW.

During HE22 through HE24, the system load typically decreases. In 2006, the maximum load reduction was 10,179 MW, while the maximum increase in wind generation was about 411. It is expected that by the 2010 timeframe, the maximum system load could decrease by about 11,297 MW during these three-hours and wind generation could increase by about 838 MW. Overall, it is expected that the CAISO needs to be able to run back generation to the extent of 12,135 MW during these three-hours.

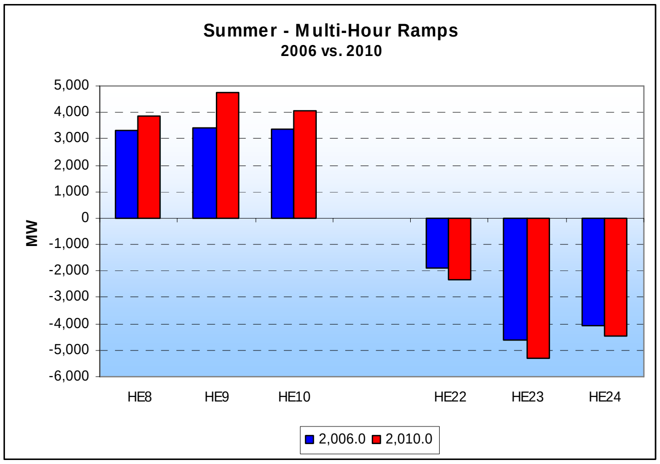


Figure 8: Actual Net Hourly Ramps

Fall Months

During the fall months (September, October & November), the load profile looks similar to the summer profile in that it has one distinct peak, which occurs around HE 20. The peak load demand in the fall months averaged about 65% of the summer peak. In the fall, wind production level shows a significant decrease from the levels observed during summer. As shown in Figure 9 below, the daily load cycle reaches a minimum around HE4 and peaks around HE20. The daily peaks typically coincide with the increase in wind production. However, as load drop off after the daily peak, the wind generation level continues to increase through midnight. During the 2006 fall, the maximum wind generation occurred between HE20 through HE24 and averaged about 575 MW or 22% of

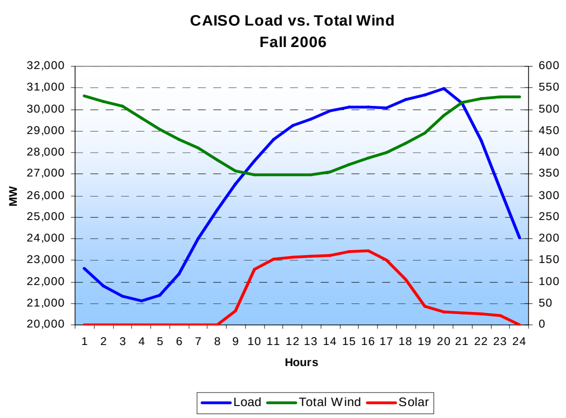


Figure 9: Actual System Load, Wind Generation and Solar Generation for Fall 2006

installed wind capacity. This pattern is expected to continue in the 2010 timeframe except the peak levels of production could be as high as 5,100 MW. In 2006, actual wind production varied from almost zero to about 1,500 MW. It is expected that the hourly variations would be between -860 MW and 1,290 MW with a standard deviation of approximately 400 MW in the 2010 timeframe.

Fall - Morning and Evening Multi-Hour Ramps

During the 2006 fall months, the largest morning load buildup typically occurs between HE7 and HE9 and the maximum increase was approximately 6,759 MW. The maximum decrease in wind generation was about 471 MWl during this time. Figure 10, shows the net average increase for each operating hour within the three-hour ramps. It is expected that by the 2010 timeframe, the maximum morning load buildup could increase to approximately 7,501 MW. Wind generation is expected to decrease by about 1,494 MW for a net increase of approximately 8,995 MW. During the 2006 evening hours (HE22 through HE24), the maximum decrease in system load was 11,213 MW, while the maximum increase in wind generation was about 298 MW. It is expected that by the 2010 timeframe, the maximum reduction in load could be about 12,445 MW, while the maximum increase in wind production could be about 1,038 MW during the evening hours. It is expected that the CAISO needs to be able to run back generation to the extent of 13,483 MW during these three-hours.

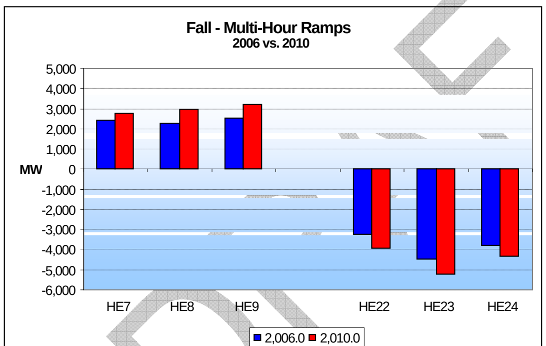


Figure 10: Actual Net Hourly Ramps.

Winter Months

During the winter months (December, January & February), the load profile looks similar to the spring in that it has two distinct peaks, one occurring around midday and the second occurring around HE19. Like the spring and fall months, the peak load demand in winter typically averages about 60% to 70% of the summer peak demand. As shown in Figure 11 on the next page, the wind production level is the lowest during the winter months but also follows the typical pattern whereby the peak generation occurs around midnight and the minimum generation occurs around HE10. During the 2006 winter months, the maximum wind generation occurred between HE20 through HE24 and averaged about 325 MW or 12.5% of installed capacity. This pattern is expected to continue in the 2010 timeframe except the peak levels of production could be as high as 4,460 MW. It is expected that the hourly variations would be between -1,425 MW and 790 MW with a standard deviation of approximately 340 MW in the 2010 timeframe.

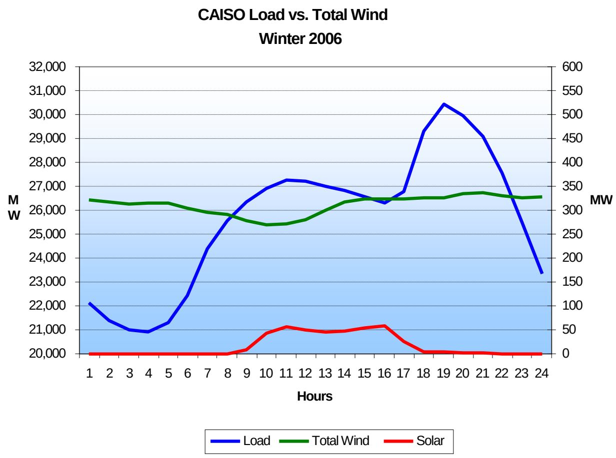


Figure 11: Actual System Load, Wind Generation and Solar Generation for Winter 2006

Winter - Morning and Evening Multi-Hour Ramps

During the 2006 winter months, the maximum morning load buildup (HE6 through HE8) was approximately 6,609 MW, while the maximum wind reduction was about 370 MW. Figure 12 below, shows the net average increase/decrease for each operating hour. In 2010, this morning load built-up is expected to increase to about 7,335 MW while the maximum wind reduction could be about 1,296 MW. During the 2006 evening hours (HE22 through HE24), the maximum system load reduction was about 7,589 MW. The increase in wind generation during this time was about 267 MW. It is expected that by the 2010 timeframe, the total system load could decreased by about 8,423 MW and the wind production could increase by about 870 MW during these three-hours. Overall, it is expected that the CAISO needs to be able to curtail generation to the extent of 9,293 MW between HE22 through HE24.

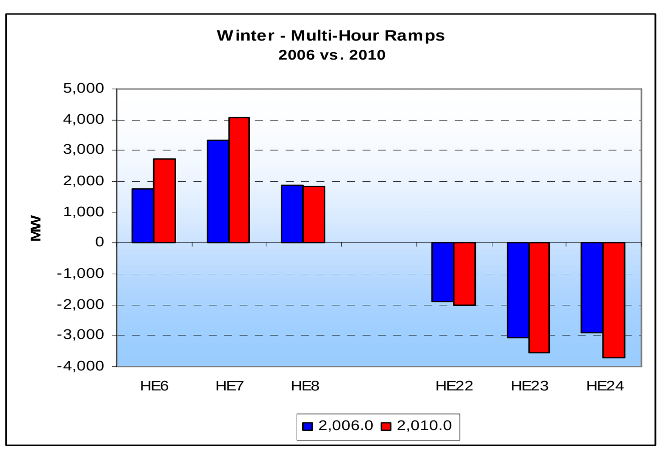


Figure 12: Actual Net Hourly Ramps

Summary of Multiple Hour Ramp Requirements

Table 2 below shows the increase in the three-hour morning and three-hour evening ramps between 2006 and 2010. The change due to intermittency column only shows the increase due to wind variability between 2006 and 2010.

Table 2: Summary of Multi-Hour Ramps

Seasons	*2006 Morning Ramps MW*	*Expected 2010 Morning Ramps MW*	*Change due to Intermittency (MW)*	*2006 Evening Ramps MW*	*Expected 2010 Evening Ramps MW*	*Change due to Intermittency (MW)*
Spring	6,860	8,494	955	7,962	9,788	984
Summer	10,090	12,664	1,529	10,589	12,135	427
Fall	7,229	8,995	1,023	11,511	13,483	740
Winter	6,979	8,631	926	7,856	9,293	603

Note: Morning Ramps – Spring & Fall: HE7 through HE9; Summer: HE8 through HE10; and Winter: HE6 through HE8.
Evening Ramps – All seasons: HE22 through HE24

As stated above, the wind generation impact analysis methodology is based on a mathematical model of the actual CAISO's scheduling, Real Time dispatch, and regulation processes and their timelines. In order to model the scheduling process, the probability distributions of the total CAISO load forecast errors and total CAISO wind generation forecast errors are necessary inputs to the model.

Hour-Ahead Load Forecasting Error

The CAISO Forecasted Load is calculated by the Automated Demand Forecasting System (ALFS). ALFS calculates the CAISO Forecasted Demand for several different timeframes. The Hour-Ahead forecast is calculated about two-hours prior to the operating hour and subsequent half-hour forecast are calculated for the remainder of the operating day. This process is repeated before each operating hour and each subsequent half-hour forecast is modified.

The Hour-Ahead Forecast Error is simply the difference between the Hour-Ahead forecast and the average hourly actual demand (excluding pump loads) for a particular operating hour. The Hour-Ahead Forecast Error is typically higher at higher load levels and is therefore more pronounced during the summer months. As shown in Table 2, during summer the Hour-Ahead load forecast error for 2006 was anywhere between -2,657 MW and 2,103 MW with a standard deviation of approximately 900 MW. Overall, for 2006 the Hour-Ahead load forecast error was found to have a mean absolute percent error (MAPE) of 2% of actual load. See Appendix C for more details.

For this study, it was assumed that the statistical characteristics of the Hour-Ahead Forecasting Error observed in 2006 would be the same in the 2010 timeframe although loads would be higher and errors tend to be higher at higher load levels. It was assumed that forecasting techniques would improve over the years to compensate for errors at higher load levels.

Season	Average (MW)	Min (MW)	Max (MW)	Standard Deviation (MW)	Autocorrelation[18]
Winter	-35	-3,849	1,519	652	0.69
Spring	-24	-2,101	1,931	601	0.73
Summer	-130	-3,771	2,446	900	0.89
Fall	-69	-2,628	2,081	687	0.83

Table 3: Summary of Hour-Ahead Forecast Demand Error (Actual Load – Forecast Load)

Figure 13 below shows the actual forecasted distribution errors (blue bars) to the theoretical error normal distribution (red line) for the summer months. Typically, during the summer months, load forecasting errors tend to be the highest and were greater than 800 MW for approximately 23% of the time. Forecasting errors for the other seasons can also be represented by truncated normal distribution functions.

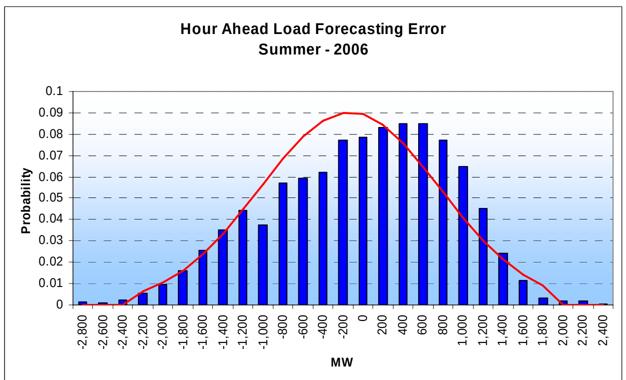


Figure 13: Summer load error distributions vs. Theoretical load error distributions

Hour-Ahead Energy Scheduling Process

With the implementation of MRTU, the CAISO will run the Hour-Ahead Scheduling Process (HASP) to lock in changes to schedules 75-minutes before the actual operating hour starts. In the actual operating day, the schedules for the wind generators in the PIRP program will also be locked in at the 75-minute point. HASP will provide 15-minute advisory schedules for internal resources and gives the CAISO the opportunity to deal with potential over generation or under-generation conditions.

As shown in Figure 14 below, the one-hour (1*hr*) block energy schedule includes 20-minute ramps between the hours. Since the actual load varies moment to moment during the hour, the average load could be greater than or less than the hourly schedules. Under generation would be handled through Real Time Unit Commitment (RTUC) or Short Term Unit Commitment (STUC[19]) by committing Short Start [20]and Fast Start[21] units if it's anticipated that resources would be deficient.

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[18] Autocorrelation values lie between ±1 and depends on the number of observations, the standard deviation of the observations, the sample mean and the current and next observation. A value of 1 indicates that the next value has a very strong positive dependence on the previous value, while a value of -1 indicates that the next value has a strong negative dependence on the previous value. An autocorrelation value of zero indicates that the current value gives no indication of what the next value will be.

[19] STUC is a reliability function for committing Short and Medium Start Units to meet the CAISO Forecast of CAISO Demand. The STUC function is performed hourly, in conjunction with RTUC and looks ahead three hours beyond the Trading Hour, at 15-minute intervals.
[20] Short Start: Generating Units that have a cycle time less than 5 hours (start up time plus Minimum Run time is less than five hours) have a start up time less than two hours and that can be fully optimized with respect to this cycle time)..

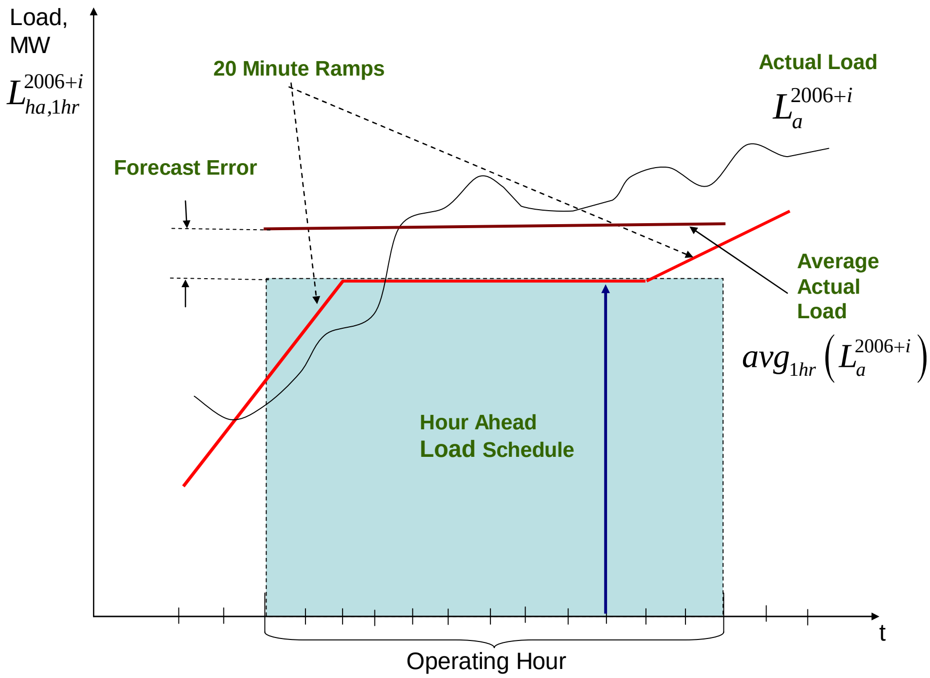


Figure 14: CAISO Simulated Hour-Ahead Load Schedule (Red Line) with Ramps

RTUC is a market process for committing resources and awarding additional Ancillary Services from internal resources at 15-minute intervals. The RTUC function runs every 15 minutes and looks ahead up to seven 15-minute intervals to ensure there is sufficient capacity to meet demand.

Should an over-generation condition continue in Real Time, the Real Time Market (RTM) will dispatch resources down using economic Bids to the extent it is possible to relieve the over generation condition. If use of economic Bids is insufficient, then supply curtailment will be performed in the order established in accordance with Section 34.10.2 of the CAISO Tariff.

Five-Minute Load Forecasting Error

In the CAISO's Real Time Market Systems, another forecasting tool called the Very Short Term Load Predictor (VSTLP) utilizes the latest ALFS Half Hour forecast and the most recent generation output from the State Estimator to forecast a 15-minute Demand Forecast and a five-minute forecast. The 15-minute forecast is used by the Real Time Unit Commitment (RTUC) and the five-minute forecast is used by Real Time Economic Dispatch. Under MRTU, all Forecasted Demand would include transmission losses but pump loads would be excluded because they are scheduled.

This five-minute forecast is run about 10-minutes before the operating interval and consists of a block of power for that time. As shown in Figure 15 below, the five-minute load forecasting error ranged from ± 349 MW. The Mean Absolute Error over the month was 0.29% and the average error over a one month interval was 1.2 MW. One Standard Deviation of five-minute load forecasting error is 98 MW.

[21] Fast Start: Start-Up Time is within the Time Horizon for any given RTUC (from 60 to 105 minutes)

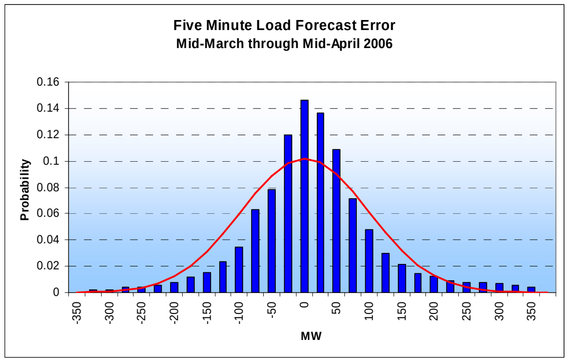


Figure 15: Comparison of five-minute load forecast error and theoretical error distribution

The autocorrelation from mid-March through mid-April was 0.61 indicating that the next five-minute interval has a positive dependence on the previous five-minute error. The Real Time load forecast is the average five-minute load forecast that includes five-minute ramps between the dispatch intervals.

Load Following

Load following is not a FERC defined Ancillary Service. Generally, the objective of a Real Time Market (RTM) is system balancing and load following on a forward-looking basis above and beyond the normal function of the Automatic Generation Control (AGC). Since the RTM is forward-looking, AGC is mainly a control rather than an Energy service. As AGC units depart from their Dispatch Operating Point (DOP) responding to frequency and net interchange deviations, they temporarily supply or consume balancing Energy. The Real Time Economic Dispatch function dispatches ahead of AGC, while AGC resolves shorter-term imbalances. The CAISO buys or sells balancing Energy at regular intervals from or to resources that participate in the RTM, allowing AGC units to move closer to their DOPs.

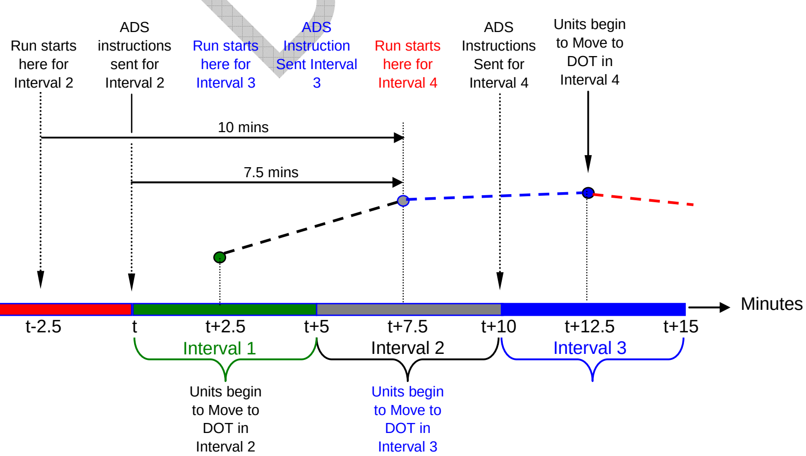


Figure 16: MRTU Timeline for five-Minute Dispatch

As shown in Figure 16 above, the Real Time Economic Dispatch software normally runs every five-minutes starting at approximately 7.5 minutes prior to the mid point of the next Dispatch Interval and produces a Dispatch Instruction for Energy for the next Dispatch Interval and advisory Dispatch

Instructions for as many as 13 future Dispatch Intervals over the RTD optimization Time-Horizon of 65 minutes. The generation dispatch for the next operating Interval is referred to as instructed deviation from schedules caused by Real Time energy dispatch. Generation and load information used for this dispatch interval is at least 10-minutes old. Generating units start to move 2.5-minutes before the interval begins and are expected to reach their dispatch operating point in five-minutes. During this five-minute interval, all deviations are met by regulation.

Load Following Requirements

Although the morning load build-up is steadily increasing during the morning hours, the actual ramping requirement for Real Time operation varies in both the positive and negative directions for any given hour. This is due to many factors including the hourly block generation and load schedules submitted in the CAISO market systems. The forecasted load for any hour is actually the forecast for mid-hour while most generators are expected to be at their scheduled operating points 10-minutes into the operating hour.

Generating units are typically moved over a 20-minute ramping period between hours to meet their next hourly schedules. Economics, ramp rates and actual operating conditions dictate which units are moved to meet their next hour schedules. While some generators are dispatched to meet their next hour schedules, other generators may have to be curtailed on a five-minute basis through the CAISO's Real Time Economic Dispatch system to maintain a balance between generation and five-minute load forecast. The blue shaded area in Figure 17 below shows the load following requirements based on 5-minutes Real Time Economic Dispatch.

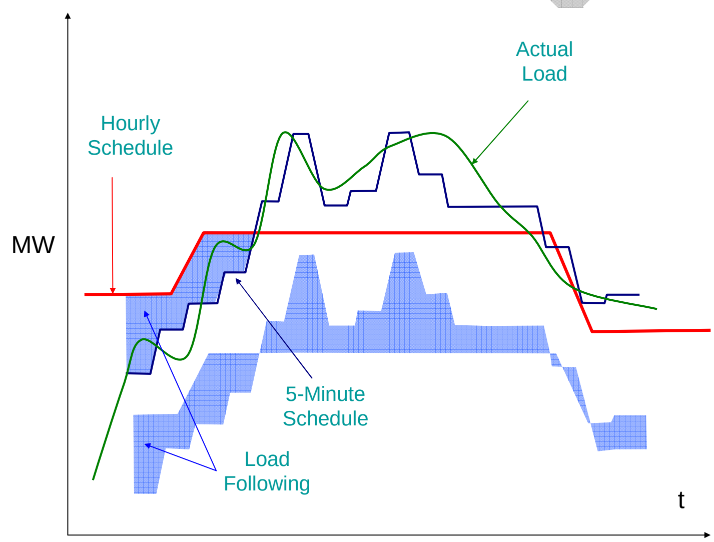


Figure 17: Load Following Requirement shown as blue shaded area

Load Following Capacity Requirements

Seasonal simulation results for Load Following capacity requirements, ramping requirements and ramp duration are shown in Figures 18, 19 and 20 respectively. As shown in Figure 18, the CAISO would require a significant increase in the supplemental energy stack to meet intra-hour load following needs. The increase is explained by the fact that the Hour-Ahead wind generation forecast error (standard deviation is evaluated as 7-9% of the total installed wind generation capacity) becomes comparable with the Hour-Ahead load forecast error (standard deviation is 600-900 MW). Figure 18 also shows the Load Following capacity requirements for all hours of a typical summer day.

The green line represents the minimum and maximum load following capacity requirements due to only wind for 2006. The red line shows the requirement for 2010 solely due to wind. As shown, the maximum upward capacity requirement of 3,500 MW occurs during HE3 and HE11. Also, the maximum downward capacity requirement of 3,450 MW occurs during HE24. The hourly upward increase is simply the difference between the top of the red arrow and the top of the green arrow for each hour. The maximum upward increase of 800 MW occurs during HE3 (3,500 – 2,700). The maximum downward capacity increase of 500 MW (3,050 -2,450) occurred in HE22.

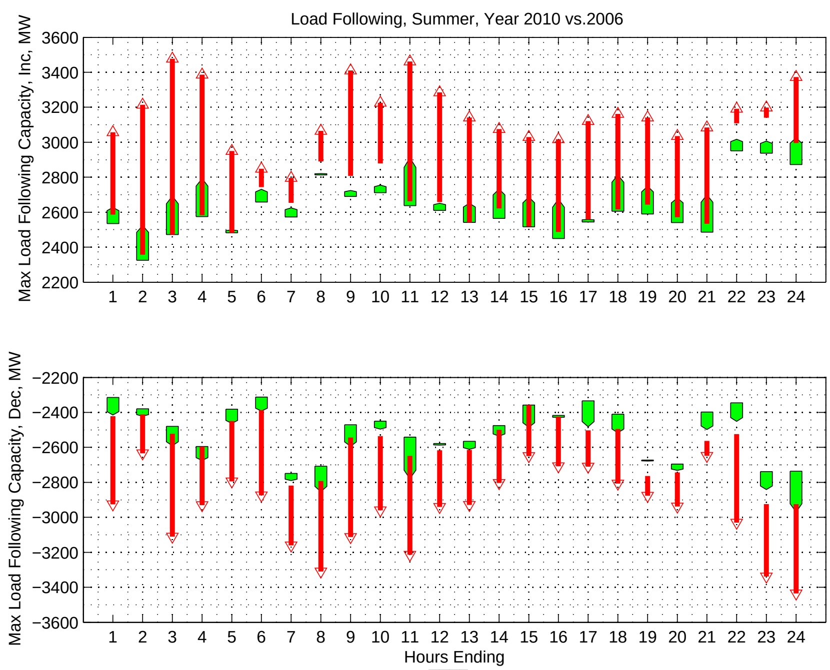


Figure 18: Load Following Capacity Requirement

Load Following Ramping Requirement

Figure 19 shows the hourly Load Following ramping requirements due to wind only for 2010 (red arrow) compared to wind only for 2006 (green arrow). It is expected that the maximum upward load following ramping requirements in 2010 will increase by 40 MW/min (HE23: 210 – 170). Similarly, the maximum downward load following ramping requirements will increase by 40 MW/min (HE9:180 – 140).

Existing Ramping Capability

There is currently about 12,651 MW of capacity certified for Ancillary Services (AS) within the CAISO. The ramp rates of these resources range between 2.25 MW/min to 187.7 MW/min. Only 7,521 MW of this capacity have ramp rates of 10 MW/min or greater. Hydro units account for 4,700 MW of the AS capacity with ramp rates of 10 MW/min or greater, while thermal resources account for the remaining 2,821 MW.

Currently, there is about 7,141 MW of capacity certified to provide regulation with ramp rates greater than 10 MW/min. Hydro facilities account for 4,700 MW of this capacity, however only five of these hydro facilities (2,788 MW) have ramp rates greater than 100 MW/min. The remaining 2,441 MW of regulating capacity are from thermal capacity, which has ramp rates between 10 and 31 MW/min.

Based on the regulation requirements shown in Table 7, the current generation mix seems adequate to meet the anticipated regulation needs. However, during droughts or low hydro years, regulation response could be slow due to the reliance of thermal units with slower ramp rates. Depending on system load, additional units may have to be committed on-line to meet regulation needs, especially during the summer months. With the current advancements in storage technology, faster ramping devices such as flywheels may be an alternative to committing additional resources to meet regulation requirements in drought years.

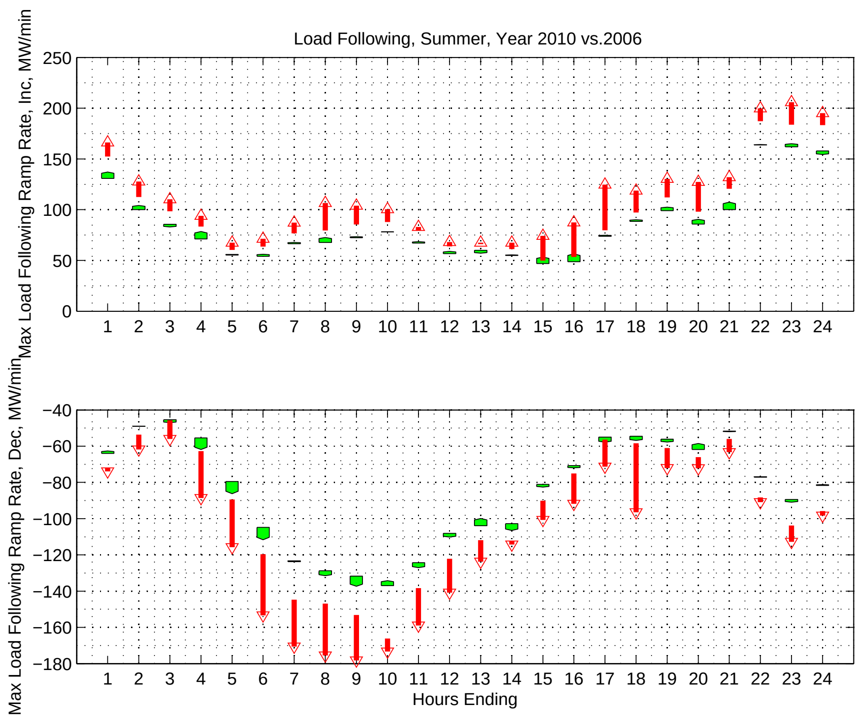


Figure 19: Load Following Ramping Requirement

Load Following Ramp Duration

As shown in Figure 20, the upward ramp duration is required for approximately 30 minutes while the downward ramp duration will be required for approximately 20 minutes. Overall, the upward load following capacity needs to be about 3,500 MW and resources within the supplemental stack should be able to ramp up at a rate of about 80 MW/min for at least 30 minutes. Similarly, in the downward direction, the resources should be able to ramp down at a rate of approximately 175 MW/min for at least 20 minutes. Refer to Appendix A for graphs showing the capacity, ramps and ramp duration for all seasons.

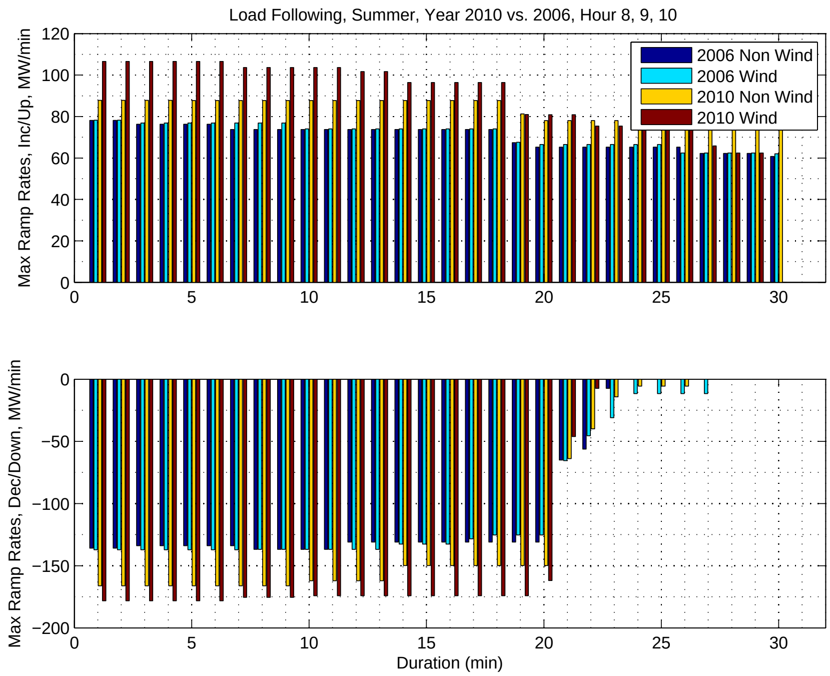


Figure 20: Load Following Ramp Duration

Study Result Summary

As shown in Table 4 below, the CAISO will require a significant increase in the supplemental energy stack to meet intra-hour load following needs. The increase is explained by the fact that the Hour-Ahead wind generation forecast error (with a standard deviation of 7-9% of the total installed wind generation capacity) becomes comparable with the Hour-Ahead load forecast error (whose standard deviation is 600-900 MW).

Table 4: *Summary of Load Following Capacity*

Season	Max Load Following Inc, MW	Max Load Following Dec, MW	Max Hourly Increase (Inc), MW	Max Hourly Increase (Dec), MW
Spring	2,850	-3,000	+800	-500
Summer	3, 470	-3,430	+800	-600
Fall	3,080	-3,200	+750	-900
Winter	2,850	-3,050	+700	-750

The CAISO maximum load following ramping requirements in 2010 is expected to increase by about ±30 to ±40 MW/min. These increases will affect ADS ramps up to 20-30 minutes long.

Table 5: *Summary of Load Following Ramps*

Season	Max Load Following Ramp Up, MW/min	Max Load Following Ramp Down, MW/min
Spring	+35	-30
Summer	+40	-40
Fall	+40	-30
Winter	+30	-40

Sensitivity with 5% Wind Forecasting Error

Holding all other assumptions constant, a sensitivity with the Hour-Ahead wind generation forecast error standard deviation of 5% of the total installed wind generation capacity was evaluated as opposed to 7% to 9%. A summary of the load following sensitivity is set forth in Table 6 below.

Table 6 Summary of Load Following Capacity (5% Error)

Season	INC 7%-9%	INC 5%	Reduction MW	Reduction %	DEC 7%-9%	DEC 5%	Reduction MW	Reduction %
Spring	2,850	2,450	400	14%	-3,000	-2,550	-450	-15%
Summer	3, 470	3,320	150	4.3%	-3,430	-3,280	-150	-4.4%
Fall	3,080	2,550	530	17.2%	-3,200	-2,600	-600	-18.8%
Winter	2,850	2,660	190	6.7%	-3,050	-2,700	-350	-11.5%

Regulation Requirements

The CAISO maintains sufficient generating capacity under automatic generation control (AGC[22]) to continuously balance its generation and interchange schedules to its Real Time Load. This generating capacity under AGC is referred to as Regulating Reserve[23]. The WECC does not specify a regulating margin based on load levels but requires adherence to the NERC's Control Performance Criteria.

The CAISO does not dispatch Regulation Reserve based on its Energy Bid Curve price but automatically dispatches regulation through AGC every four-seconds to meet moment-to-moment fluctuations in customer load demand and to correct for the unintended fluctuations in generation. Regulation is wholly based on the resource's effectiveness to maintain system-scheduled frequency and maintain scheduled flows between control areas taking into consideration resource's operating constraints. To the extent a resource is moved away from its Dispatch Operating Point (DOP) by AGC (i.e., it is not awarded Imbalance Energy); the Market Clearing software assumes that the resource is brought back to its DOP in the next market interval. In doing so, the net Energy delivery from the unit, both above and below its DOP, averaged over time, to zero.

To meet the NERC's Control Performance Criteria, the CAISO typically procures ± 350 MW of regulating reserve (approximately 1 to 1.5% of load) on a given day. On days with high load demand additional regulation is procured. Although the regulation dispatch is done every four seconds, the regulation margin has to be adequate to meet deviations within a five-minute dispatch interval.

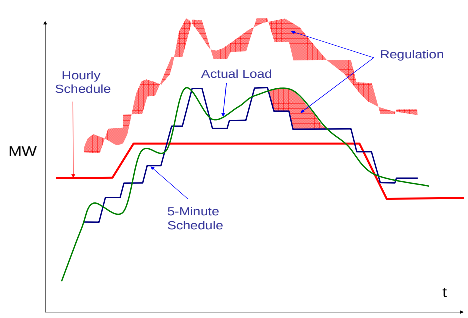


Figure 21: Regulation Requirement shown as the red shaded area

[22] The WECC defines AGC as equipment that automatically adjusts a control area's generation from a central location to maintain its interchange schedule plus frequency bias.

[23] The WECC defines Regulating Reserve as sufficient spinning reserve, immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the control area to meet NERC's *Control Performance Criteria.*

As stated above, ADS instructions are issued approximately 7.5 minutes in advance of the desired operating interval leaving approximately 5 minutes for units to move to their desired operating point. As shown in Figure 21 above, during this five-minute timeframe, deviation from generation schedules is compensated with regulation, which is dispatch through Automatic Generation Control (AGC) within the CAISO's Energy Management System (EMS). Regulation is not dispatched by the CAISO's Real Time Market System.

Regulation Capacity Requirements

The CAISO regulation capacity requirements would increase noticeably during certain hour ranges. The increase is explained by increasing inaccuracy of the persistence model used in this study for the Real Time wind generation forecast (this model reflects the current approach implicitly used by the CAISO's Real Time Dispatch). The following table summarizes the maximum expected values.

As shown in Figure 22 below, the maximum upward regulation capacity requirement of 480 MW occurs during HE9, while the maximum downward capacity requirement of -750 MW occurs during HE18. The hourly upward increase is simply the difference between the top of the red arrow and the top of the green arrow for each hour. The hourly upward increase is simply the difference between the top of the red arrow and the top of the green arrow for each hour. The maximum increase of 230 MW occurs during HE9 (480 MW – 250 MW). The maximum downward increase of 500 MW (750 MW -250 MW) occurred in HE18.

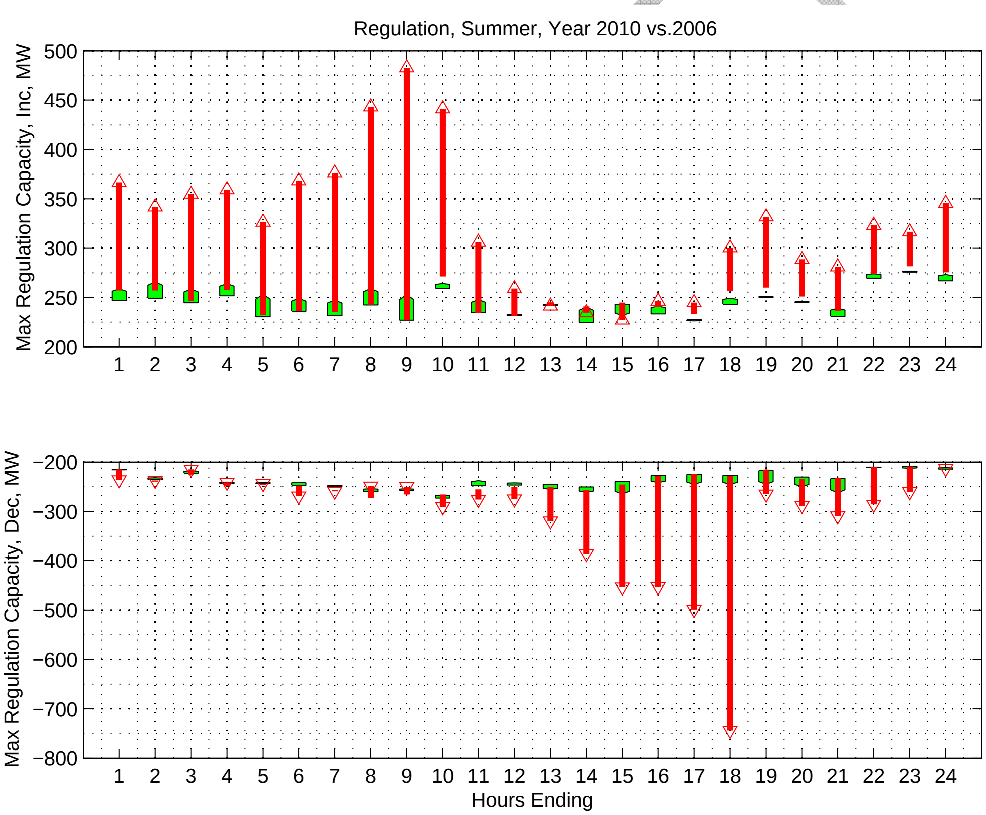


Figure 22: Maximum Regulation Capacity

Regulation Ramping Requirements

Figure 23 below shows the hourly regulation ramping requirements due to the addition of only wind. It is expected that the maximum upward regulation ramping requirements for 2010 summer will increase by 10 MW/min (HE10: 140 MW – 130 MW). The maximum downward regulation requirement in 2010 is expected to increase by 18 MW/min (HE10:115 - 97). This is not expected to create any operational concerns because it falls within the ramping capability of the existing units. The regulation ramp duration is expected to increase by about ±10 to ±25 MW/min and could last for about five minutes. For further information on this see Appendix A.

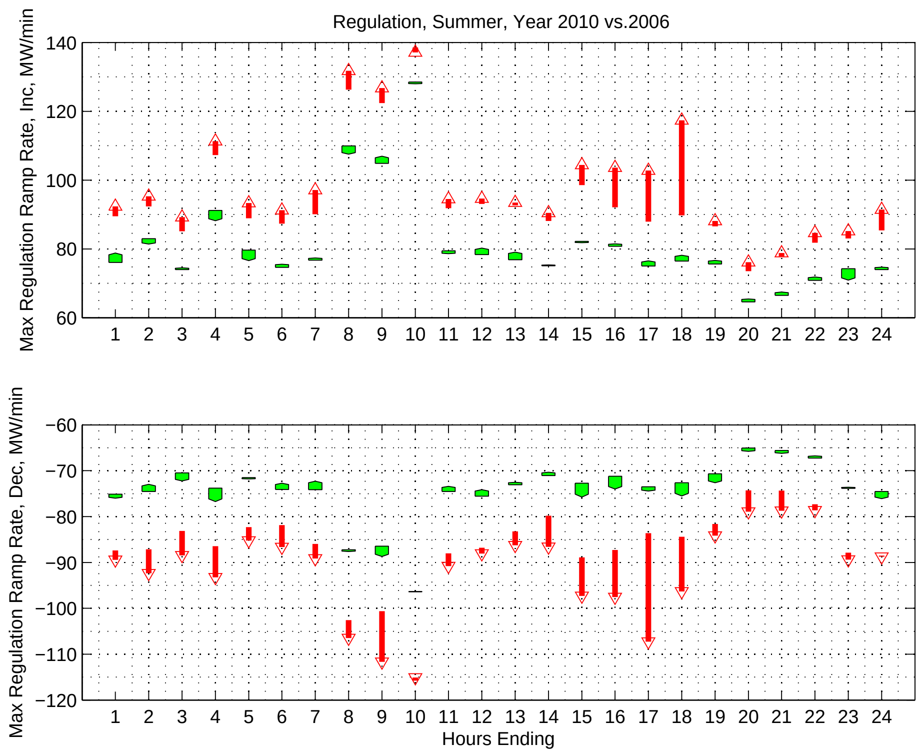


Figure 23: Regulation Ramp Rate

Regulation Ramping Duration

As shown in Figure 24 below, both the upward and downward ramp durations are required for about five minutes. Overall, the upward regulating capacity needs to be about 480 MW and resources within the supplemental stack should be able to ramp up at a rate of about 80 MW/min for at least five minutes. Similarly, in the downward direction, the regulating capacity needs to be about -750 MW and resources should be able to ramp down at a rate of approximately 80 MW/min for at least five minutes. Refer to Appendix A for plots showing the load following and regulation capacity, ramps and ramp duration for all seasons.

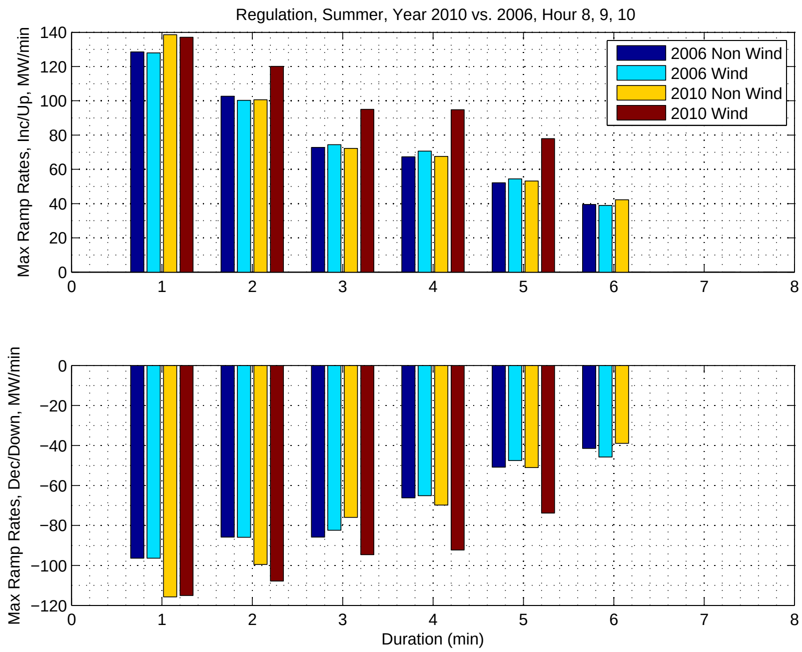


Figure 24: Regulation Ramp Duration

Regulation Study Result Summary

The CAISO regulation capacity requirements would increase noticeably during certain hours. The increase is explained by increasing inaccuracy of the persistence model used in this study for the Real Time wind generation forecast. Table 7 below summarizes the maximum expected values.

Table 7: Summary of Regulation Capacity

Season	Max Regulation Up, MW	Max Regulation Down, MW	Max Hourly Increase (Up), MW	Max Hourly Increase (Down), MW
Spring	+510	-550	+240 (HE18)	-300 (HE18)
Summer	+480	-750	+230 (HE09)	-500 (HE18)
Fall	+400	-525	+170 (HE06, HE18)	-275 (HE18)
Winter	+475	-370	+250 (HE18)	-100 (HE10)

The CAISO regulation ramping requirements in 2010 will increase by about ±20-35 MW/min (see the Table 8). These increases will affect AGC ramps up to 5 minutes long.

Table 8: Summary of Regulation Ramps

Seasons	***Max Regulation Ramp Up, MW/min***	***Max Regulation Ramp Down, MW/min***
Spring	+20	-25
Summer	+10	-18
Fall	+25	-20
Winter	+15	-15

Over Generation Conditions

One of the concerns from grid operators about wind generation is that its energy can show up unexpectedly causing an imbalance between load and generation. Whenever there is an imbalance between generation and load, the CAISO's Automatic Generation Control (AGC) system sends control signals to units on regulation to move to different operating points in order to correct the imbalance. During overgeneration conditions, regulating units are moved to the bottom of their regulating range and the Real Time Economic Dispatch System drives units with decremental (DEC) bids to their minimum operating points. At times, operators may run out of DEC bids and have to go out of market to drive the units down further or command units to shut down.

Over generation occurs whenever there is still more generation than load and the operators cannot move generators to lower level of production. The controllable generation and imports are at their minimum levels or are shut down, exports are maximized and the total net generation production still exceeds the system load. The real-time energy prices typically go negative and the CAISO, at times, literally pays adjacent control areas to take the excess energy. The controllable generation and imports are at minimum levels or are shut down, exports are maximized and the total net generation production still exceeds the system load. This condition is most likely to occur during the following circumstances:

- light spring load conditions with loads around 22,000 MW or less,
- all the nuclear plants on-line and at maximum production,
- hydro generation at high production levels due to rapid snow melt in the mountains,
- long start thermal units on line and operating at their minimum levels because they are required for future operating hours,
- other generation in a “Must Take” status or required for local reliability reasons, and
- wind generation at high production levels.

Figure 25 below helps to illustrate the overgeneration problem:

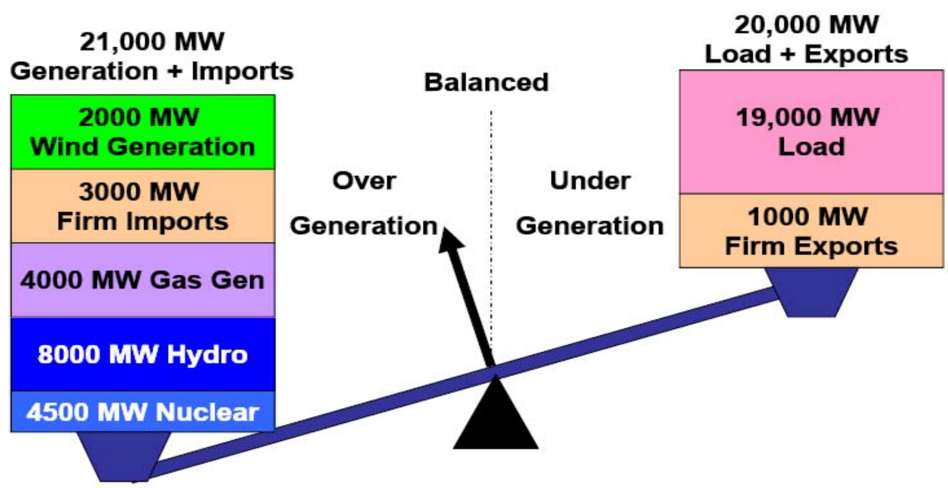


Figure 25: Overgeneration Example

In addition, the problem is exacerbated by the lack of a Day-Ahead market, lack of an accurate Day-Ahead forecast of wind generation energy production and the lack of a system to check and verify the feasibility of next day schedules. Even if some portion of the wind generation energy is scheduled in the Hour-Ahead market, it may be too late to correct the mismatches between load and generation schedules. The SC's help by attempting to sell the excess energy to other entities within the interconnection. The over generation problem finally gets resolved but the operators may incur several CPS2 violations in the process.

The CEC 2007 IAP Final Report identified overgeneration as potential problem during light load conditions. The minimum operating points for many of the generators in the CAISO market database do not always match the operator's experience with the unit's actual minimum operating levels due to environmental, economic and operating constraints of the plants.

2006-2007 Over Generation Analysis

In 2006, there were 45 hours of over-generation problems on 20 different days and in 2007 there were six reports from January through May 2007. All of the incidents identified a problem with a mismatch or generation schedules with forecasted loads. Although wind production levels played a very small role in over-generation problems in 2006 and 2007, it is anticipated that high levels of wind generation in the 2010 timeframe could cause operational challenges during light load conditions.

Example of a typical log entry: for over-generation:

"05/06/2007 - 0615 Real-Time Over-Generation"

"**Description:** "Real-time over-generation condition for HE 0700"

> ***Details:*** *"For hour(s) ending 07, the CAISO has determined Over-Generation in the amount(s) of 500 MW. The CAISO may be invoking other steps in its Over-Generation procedure G-202, including but not limited to purchasing Out-Of-Market (OOM) decremental Energy for this hour. Scheduling Coordinators should contact the CAISO Generation Dispatcher if they desire to provide OOM decremental Energy for this period. To the extent that Scheduling Coordinators do not respond to this CAISO notice of Over-Generation, the CAISO may invoke other steps in the Over-Generation procedure G-202, including but not limited to Pro-Rata Reductions and Mandatory Generation Reductions."*

An example of over-generation with a clear correlation with wind generation energy production occurred in April 2006 for the HE13 through HE19. At around 1130 hours in the morning, the wind generation ramped up from 600 MW to over 1,000 MW in approximately one hour. The operator declared a 500 MW over generation condition and the ACE remained high during this period. This event occurred on a light load day as the system load was in the 23,000 ±500MW range at the time.

Figure 26 shows the wind generation production for that day and the corresponding ACE. Figure 27 shows the real-time prices for the same day and the real time prices were negative for a significant portion of the over generation period.

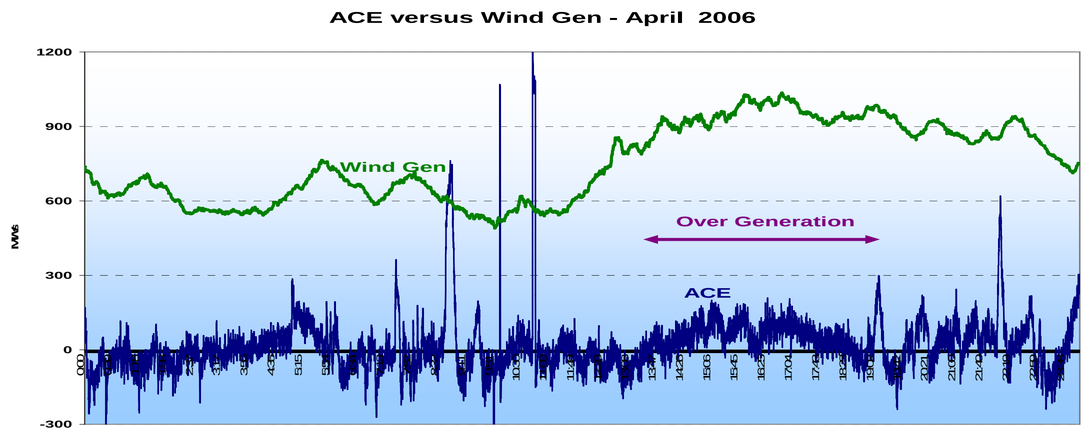


Figure 26 – ACE versus Wind Gen

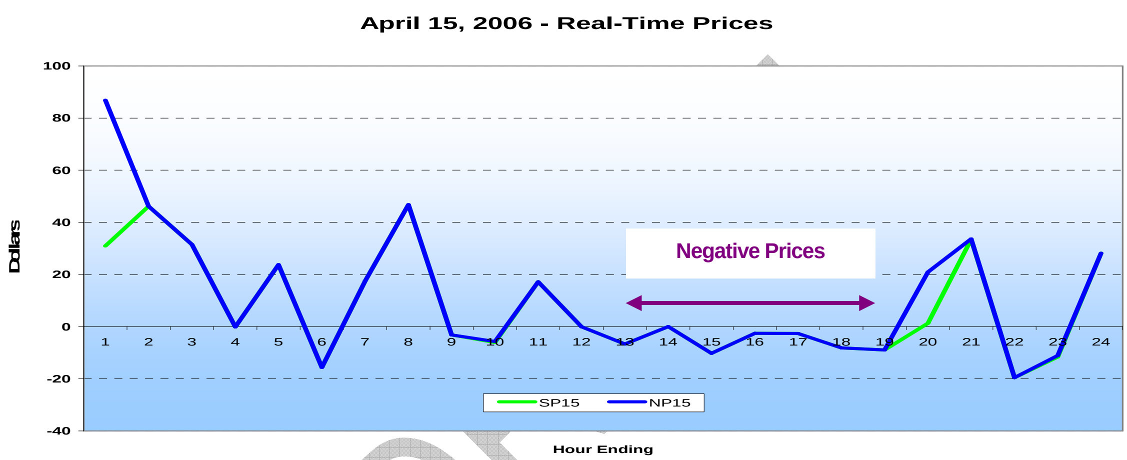


Figure 27: Real Time Prices During Overgeneration Conditions

During the 2006 Spring months (March, April & May) there were 208 hours when the CAISO load was less than 20,000 MW. The minimum amount off load (minus wind generation) recorded in 2006 was 18,070 MW. Table 9, shows a summary of the minimum generation that were on line during light conditions.

Table 9: Minimum Generation Levels by Technology During Light Load

Generation/Load	Production Level Spring 2006 (MW)
Nuclear	4,528
Minimum "Must Take" such as QFs	2,400
Minimum Geysers	650
Minimum Thermal	1,000
Minimum Hydro	3,700
Minimum Interchange	2,880
Total Generation plus Interchange	***15,158***
Minimum Load	18,070
Difference	***2,912***

Based on the minimum generation levels shown in Table 8, assuming conditions remain the same in 2010, the maximum amount of wind generation that could be accommodated would be about 2,912 MW.

The critical components for over-generation appear to be maximum hydro generation, maximum wind generation, low system load, all nuclear plants on line, heavy imports on the ties and other generation required to be on-line due to operating constraints. Under these conditions, over-generation is likely. Light loads and high wind generation is not a good gauge for over-generation. It is therefore difficult to predict the number of hours wind generation would have to be curtailed in 2010, during light load conditions, without accurate Day-Ahead wind forecast. This problem is exacerbated during favorable hydro conditions or when SCs have already made commitments in the forward markets to purchase inexpensive imports.

The fact that the CAISO had 45 hours of over generation in 2006 with the current level of wind generation on the system leads us to conclude that we can expect over-generation problems in the future when we have 3000+ MW of wind generation. Whether wind is the cause or other factors are the cause, the CAISO will have to take action to reduce the amount of generation on the system when this occurs. This will include sending dispatch notices to wind generation facilities for their operators to take action to reduce their generation at the wind facilities. The CAISO recognizes the State's resource loading order which places renewable resources low on the list for pro-rata cuts, but the CAISO may occasionally have to implement such cuts to insure the reliability of the system.

Over Generation in the MRTU Environment

Under the new MRTU Integrated Forward Market (IFM), over generation is managed as part of the IFM Unit Commitment process. The IFM ensures that the scheduled Supply for each Trading Hour equals the quantity of scheduled Demand. Wind generation energy does not have to be scheduled in the Day-Ahead market but the SC's may elect to schedule some of the energy. After the Day-Ahead Market closes, the CAISO runs the Residual Unit Commitment (RUC) process to ensure sufficient generation will be on-line the next day to meet reliability requirements. If more energy supply is scheduled than the CAISO forecast Demand for the next day, then the RUC process may identify the need to de-commit resources. One key input before the RUC process is initiated will be a Day-Ahead forecast for wind energy production. RUC should not identify the need for additional generation if there is a good chance that the generation will not be needed due to forecasted wind generation energy production.

RUC does not automatically de-commit a resource scheduled in the IFM. The CAISO Operator may communicate the need for de-commitment of resources with affected Market Participants. If the Day-Ahead wind generation forecast is reasonable accurate, the potential over generation problems can be resolved and feasible energy production schedules created for the next operating day.

In the actual operating day, the CAISO runs the Hour-Ahead Scheduling Process (HASP) that is used to lock in changes to schedules 75 minutes before the actual operating hour starts. The schedules for the wind generators in the PIRP program will be locked in at the 75 minute point. HASP provides the CAISO the opportunity to deal with over generation by economically clearing an Export Bid in HASP, in order to avoid manual intervention to decrease generation in Real Time. If the over-generation condition continues in Real-Time, the Real Time Market (RTM) attempts to dispatch resources down using economic Bids to the extent possible to relieve the over generation condition. If use of economic Bids is insufficient, then supply curtailment is performed in the order established in accordance with Section 34.10.2 of the CAISO Tariff.

Lastly, Exceptional Dispatches may be necessary to resolve the over generation condition. The RUC solution identifies to the CAISO Operator resources that may need to be considered for de-commitment. The CAISO Operator reviews and assesses the results prior to making any manual de-commitment decisions. The RTM applications use the latest available information about resource availability and network status; in fact, the optimal Dispatch is initialized at the SE solution that is provided by the Energy Management System (EMS).

Conclusions and Recommendations about Over Generation

- Over generation does occur with the existing amount of wind generation but it is relatively rare occurrence.

- The lack of good Day-Ahead wind generation forecast contributes to the problem. Without good forecasts, other generation resources and imports on the ties may be over scheduled. This mismatch of energy production schedules with forecasted loads is a key part of the problem.

- The addition of large amounts of wind generation facilities to meet the RPS goals will exacerbate the problem. The fact that this problem is already visible with the amount of installed wind generation in our area today means that this will become a much more serious problem as the amount of wind generation doubles and triples in the near future.

- The MRTU Integrated Forward Market should help to mitigate the problem once MRTU goes live in 2008 as it will ensure the generation schedules match the load forecast. Accurate Day-Ahead wind generation forecasts will be a key component for the Day-Ahead RUC process.

- As pointed out in the CEC IAP report, the wind generation operators should be prepared to curtail some wind generation production for up to 100 hours per year to mitigate serious over generation conditions in the future. The amount of renewable energy that will be lost will be small. The hourly pro-rata cuts will probably be less than 500 MW. It will be expensive to fix the problem by other means. Curtailment of some wind generation energy production for a few hours per year is the much more practical solution.

- The CAISO must work with the wind generator operators to ensure procedures, protocols, and communication facilities are in place so dispatch commands can be communicated to the plant operators.

- Additional storage capability on the system would help to mitigate both over generation and large ramp conditions. For example, the upgrade of the transmission system to the Fresno area would allow the frequent use of the 3rd pump at the Helms Pump Storage plant. The 3rd pump adds 300 MW of additional load to the system which would help to absorb the increased wind generation at night and during light load periods.

- We must continue to explore other storage technologies and off-peak loads that can be combined with the wind generation production. The ISO should support the plug-in hybrid vehicle projects underway at both SCE and PG&E as plug-in hybrids could ultimately add significant night time load to the system.

Chapter 6 – PIRP II Enhancements

In 2003 the CAISO created the Participating Intermittent Resource Program (PIRP) program to lower a perceived barrier to wind generation participation in the CAISO markets and real-time operations. PIRP allows intermittent resources to schedule energy in the hour-ahead market without incurring imbalance charges when the delivered energy differs from the scheduled amount. Participating Intermittent Resources that schedule in accordance with the Hour-Ahead forecast provided by the forecast vendor will not receive Imbalance Energy charges for deviations across a ten-minute Settlement Interval. Instead the mega-watt deviations from a Participating Intermittent Resource will be netted across a calendar month and settled at a weighted-average price. With an unbiased, state-of-the-art forecast, the expected net deviation should be somewhat low

The success of the Participating Intermittent Resource Program (PIRP) is dependent on the accuracy of the forecast provided to the PIR's SC by a Forecast Service Provider (FSP) 2 hours and 45 minutes before the operating hour (the Hour-Ahead (HA) forecast). The HA forecast requires real-time data from each PIRs site and the forecast accuracy is dependent on the quality of data from that site. Unfortunately, the original implementation of the PIRP application did not anticipate the CAISO need to check the data[24] quality from each of the wind generators and the need for the ISO to report data problems to the PIRs. The need for an errant data feedback system became more obvious as more PIRs were brought on line and into the program. An informal manual email system was established to fill the feedback gap with the forecasting service provider doing the data quality checks. Although this improved the data quality, it included serious delays in the reporting of bad data as the data checking was too far downstream in the process. Delays of several days or longer were not uncommon to identify and correct communication problems, missing data and bad data from devices at that various wind farms.

In 2006, the CAISO started work on major upgrades to the PIRP system to fix this problem and add other system features. The PIRP II project included major enhancements to the PIRP application software to detect bad data and to automatically report problems in a timely manner to the wind farm operators. The primary objective was to provide PIR SCs with timely information regarding their participation in PIRP without manual intervention. Information provided to the PIR SCs give immediate errant data feedback when the PIR retrieves their HA Forecast, thus eliminating the need for a manual feedback system. With the added visibility to errant data that PIRP II provides, we are now undergoing a study to determine the different types of errant data, what is the cause of the errant data, can we determine where the causes of errant data occur, how responsive are the PIRs to the notifications of errant data and what corrective action can be taken to improve the forecast accuracy going forward.

The PIRP II also addressed issues such as future scalability, added an internal PIRP administrator console for ease of managing users, resources and application configuration settings, improves audit capability of data the FSP provided to ISO, and provided safeguards for the speedy recovery of the PIRP database should a loss of data occur.

The new PIRP II system went into operation at the CAISO in May 2007.

[24] Errant data is when the PIRP application has determined that for one or more reasons, the Resource's Met/Gen data is either unavailable or is not passing one of the many data quality validations.

Chapter 7 - Storage Technology

Battery storage and pump hydro storage systems have been around for many years so the concept of energy storage is not new. Large pump storage facilities have been proven to be very effective in shifting large quantities of low cost off-peak energy production to delivery during high cost on-peak energy periods. However, large pump hydro storage facilities are quite costly and there are very few locations where they can be built. Battery storage systems are also relatively costly and have limited amount of energy storage.

New types of energy storage technologies are need that can help with the integration of large amounts of renewables and energy from intermittent resources. R&D efforts have accelerated over the past several years to develop and test new storage systems. Hydrogen, compressed air, closed loop pump hydro storage; flywheel systems, super capacitors, flow batteries, and other types of storage are all being evaluated as potential new storage technology.

There are a number of problems with new storage technology that must be overcome:

- The capital costs are quite high for new storage system – typically $1 million to $1.5 million per MW of capacity.
- The efficiency of new systems is still low. Efficiency numbers are not typically available but they appear to be less than 70% for many of the technologies. This means that 30% or more of the energy supplied to these system is not recovered. Some technologies have losses due to pump operation, some have compressor loads, and others have invertor losses. The efficiency of the high speed flywheels is better than most of the new technologies as they are in the 80% to 90% range. Their losses are due to the power electronics of the inverters and not due to losses in the flywheel itself.
- Storage systems are a net negative system device. They look more like a load than a generator. Their preferred operating point will be zero or slightly negative as they consume power from the grid to perform their storage function. When they are absorbing power from the grid, they are essentially buying power at the real-time energy price and when they are supplying power, they are selling power at the real-time energy price. One question will be whether there should be a special tariff for storage systems.
- The amount of energy storage capability of these systems is typically quite limited. Batteries and high speed flywheels can deliver their rated output for 10 to 15 minutes. Flow batteries; hydrogen storage and compressed air systems can probably deliver energy for an hour or two but so far haven't demonstrated they could delivery energy for ten hours or longer.
- We do not have good economic models or operating data on the various technologies to prove they make a good business case.
- To encourage commercial investment in new storage technologies, the first deployments may need investment tax credits, similar to those enjoyed by the wind generators for the past several years.
- The first commercial deployments of new storage technology will probably need some type of a grid services performance contract to share the financial risk. This will help the

owner/operator get financial backing for the new venture and a chance to validate the business economics of the system. Part of the services they provide could still be market based and part could be contract performance based, similar to RMR contracts.

- DOE and CEC investments in Storage Technology R&D projects are critical for the development of these new technologies. The results of the R&D projects should be published to provide the data required for commercialization.

- The CAISO needs to continue to develop new methodologies for dispatching different types of storage systems. The traditional AGC signal sent to hydro generation for regulation services is probably not going to work for storage systems like flywheels that need lots of charge and discharge cycles per hour.

- Based on the industry feedback to the CAISO on the LEAPS project, it is clear that the CAISO should not be the owner/operator of large hydro pump storage facilities. This may also be true for other types of storage technology. Should all storage facilities be independently owned and their services market based or should some of them be owned and operated by the transmission operators?

7.1. Benefits of Storage Technology

7.1.1. Mitigation of over generation problems

Dispatchable loads and energy storage systems can add significant flexibility to the operation of the power grid. They can often respond in a few seconds to commands to absorb energy. Each type of technology has its unique response rate, some in one-second and others within a few minutes, but all can quickly connect to the system and ramp up to add load to the system. For example, large pump storage plants can be switched from generation mode to pumping mode within approximately 15 minutes. The addition of up to 500 MW of new storage capability to the system, with the ability to respond to CAISO dispatch commands, would add major flexibility for the operators to deal with over generation problems. Load could be added to the system either by the storage owner/operator as a market participant or by dispatch notice from the CAISO to rebalance the system.

A second issue is the need to increase the amount of off-peak load on the system that could take advantage of the off-peak energy production from wind generation. An example would be the dispatch of major state pumping load to increase or decrease system load as the wind generation production increases and decreases. Another example is the potential growth in load from plug-in hybrid vehicles. Both of these future changes could provide system load that is matched with the off-peak energy production from renewables.

7.1.2. Mitigation of large ramps can reduce the need for more quick start fossil fueled generating units and reduce the production of greenhouse gases.

Storage systems can quickly supply energy to the system when needed and help with the mitigation of large load and/or wind generation energy ramps. The CEC IAP report identified the fact that the CAISO will have to deal with energy ramps of several thousand megawatts per hour during some periods. Short term ramps that often occur at the top of the hour can be another challenge. Storage systems that can quickly inject power into the system or add a block of load mitigate some of ramp problems and allow other resources to be dispatched and catch-up with the ramp. Flywheel systems, for example, can ramp up to full output in approximately one-second and hold that level of production for 10 to 15 minutes. Hydro units and pump storage units all have fast ramp rates and can usually sustain the maximum level of production for several hours or longer. A portfolio of fast responding units like hydro and storage facilities in combination with other units that can move through large ranges of output will enhance the integration of large amounts of renewable resources.

Storage technology has the advantage of not using fossil fuel so storage facilities do not directly contribute to greenhouse gas production. If the energy in storage comes from renewable resources, they are simply storing the green energy and delivering it back to the system when it is needed. If load is ramping up as wind is ramping down, storage can provide the added energy to mitigate the resulting net energy ramp.

7.1.3. Provide Ancillary Services – regulation and operating reserves

As discussed earlier in this report, an increase in the amount of wind generation will require increases in the amount of regulation and load following capability. Flywheel systems are ideally suited to provide some of the added regulation. Flywheels could provide up to 40 MW of regulation services and eliminate the need to move fossil fuel units up and down a few megawatts at a time. Hydro, pump storage and fossil fuel units will still be needed for large ACE deviations and macro AGC control.

Hydro generation and pump storage are excellent sources for the required system operating reserves as they can provide this capacity without use of fossil fuel. They can be synchronized to the system and be ready to produce substantial energy on demand. A pump storage plant like Helms Pump Storage Facility can provide 600 MW or more of operating reserves and rapidly ramp up its output if required for the loss of a large unit on the system.

7.1.4. Provide reactive energy for voltage support and, depending on location and energy delivery capability, reduce the need for RMR units.

Storage technology typically uses some other medium to store the electrical energy. This can be a rotating mass, or water, or chemical, or compressed air or hydrogen or something other than storage of electrons. Most of these systems require some type of a generator and an inverter to create 60 Hz synchronize power that is delivered back to the grid. If they have an inverter, then this device can also deliver reactive power as well as real power which means they can help to support the voltage in that area. It is also possible to locate these devices in a warehouse or a location near a load center which means they can provide reactive power to support the voltage in a transmission constrained area. Storage technology devices could compete with Reliability Must Run (RMR) generators to provide reactive power, dynamic VARs, and voltage support.

7.1.5. Shifting of energy from off peak to on-peak delivery.

One value of large storage systems is the ability to absorb energy during off peak periods and then deliver the energy to the system at peak periods. If the wholesale price differential between off-peak and on-peak periods is large, then the storage operator can make a potential profit. If the off-peak price is negative and the on-peak price is large, then it should be easy to justify.

All storage systems are net-negative devices which mean there is some loss of energy in the systems. If the device has a “round-trip” efficiency of 60%, then for every 100 MWHrs of energy input into the storage device, only 60 MWH of energy is recovered and returned to the grid. Therefore, the price differential between off-peak and on-peak energy would need to be 2 to 1 or greater to make a profit with the storage system for shifting of energy. If the on-peak/off-peak price differential is small, then the owner/operators of storage technology need to sell additional services such as regulation or operating reserve capacity to supplement the profit stream for the unit.

7.2. Pump Storage and need for 3 pump operation at Helms

Pump storage is a proven storage technology. It has been around for many years and California is fortunate to have a number of pump storage facilities. One of the largest facilities is the Helms Pump Storage Facility that was built in the early 1980's with three units. Each unit is rated at 400 MW in generation mode and 310 MW in pumping mode for a total of 1200 MW generating mode and -930 MW pumping mode. The pump motors are non-variable speed motors so the load operation is rather stepwise as shown in Figure 27 as the units come on and off in 300 MW steps. When a pump is tripped, it actually moves the frequency of the Western Interconnection enough to trigger the system frequency alarm.

A sort of the hourly energy data shows the amount of time for the various pumping modes at the plant.

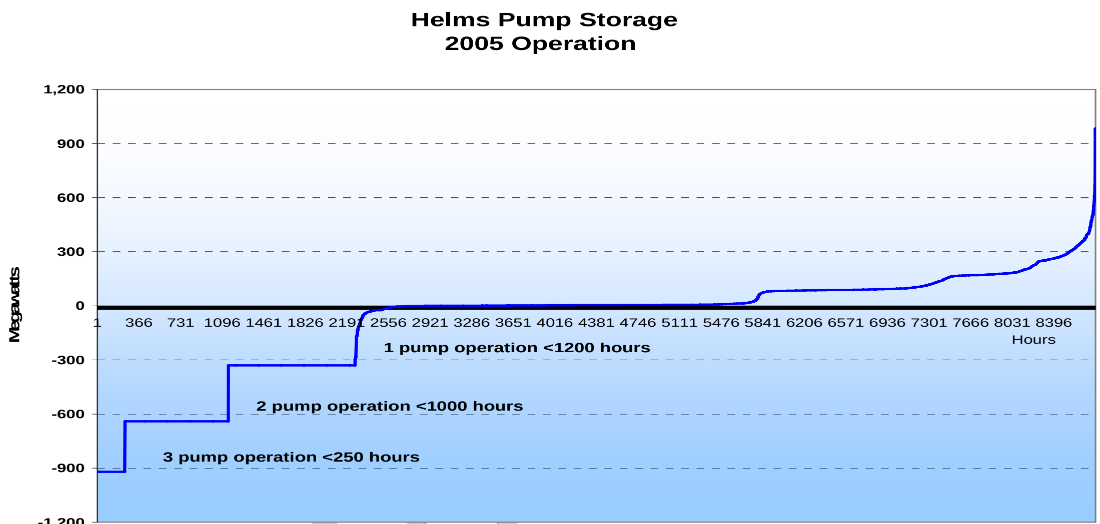
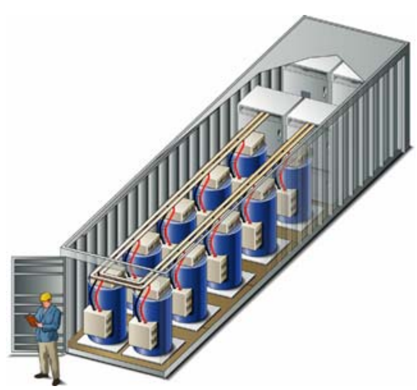


Figure 27: Helms Pump Storage Operation in 2005



The simultaneous operation of all three pumps at Helms is currently limited by transmission constraints in the Fresno area. The fact that three pumps are on less than 3% of the total time per year will become a more serious problem as the amount of wind generation on the system increases. An additional 300 MW load at Helms due to three pump operation instead of only one or two pumps during off peak periods would add a valuable sink for the excess off-peak wind generation. PG&E has proposed a transmission upgrade plan for the Fresno/Helms area that would enable three pump operations for many additional hours per year. The new plan will also move the energy from the wind farms in Tehachapi to Helms facility. Both the GE studies and the CAISO studies have shown that operation of three pumps at Helms will help to mitigate the potential future over-generation problems.

7.3. Use of Flywheel technology for additional regulation

The CEC funded a field test in 2005-6 for a 100 KVA high speed flywheel system in San Ramon on the CAISO controlled grid. The CAISO sent ACE signals to the unit to verify the unit's ability to provide regulation and frequency control services to the grid. This test was successfully concluded in early 2007. The system was highly reliable and met all performance standards.

The next step is the potential commercial installation of a 20 MVA flywheel system on the CAISO's controlled grid and for the flywheel system to provide regulation services. A proposed 20 MVA Beacon Power high speed flywheel system is shown in the pictures at the end of the previous page.

KEMA was asked to evaluate the environmental impact of using flywheel technology for regulation services versus a conventional fossil fired power plant. Their report[25] concludes "that flywheel-based frequency regulation can be expected to produce significantly less CO_2 for all three regions (of the country) and all the generation technologies, as well as less NO_x and SO_2 emission for all technologies in the CAISO region....When the flywheel system was compared against "peaker" plants for the same fossil generation technologies, the emissions advantages of the flywheel system were even greater."

The flywheel system has a very fast dynamic response rate and can switch from full charge to full discharge in 1 second. This fast response rate and ramp rate makes it an ideal technology for frequency and ACE regulation. The high availability of the system and high efficiency make it an excellent candidate for commercial deployment of the system. As new wind generation is added to the system and the amount of regulation services required increases, a 20 MW or 40 MW flywheel systems may be the best environmental choice for meeting the regulation needs.

7.4. New storage technologies – Hydrogen, flow based batteries, compressed air storage, etc.

7.4.1. Hydrogen storage

Hydrogen storage is now being proposed as the answer to the need for new storage capability. It has the advantage of being easy to make as electrolysis is a tried and true method for separating water into hydrogen and oxygen molecules. The energy can be recovered by either using a fuel cell to recombine the hydrogen and oxygen or the hydrogen can be used as fuel in a steam boiler or combustion engine.

[25] "Emissions Comparison for a 20 MW Flywheel-based Frequency Regulation Power Plant", KEMA Project:BPCC.0003.001 January 8, 2007 Final Report

On May 8, 2006, DOE, NREL and Xcel Energy signed a two year cooperative agreement for a "wind to hydrogen" research, development and demonstration project. The research will examine hydrogen production from wind power and the electric grid. The hydrogen will be produced through electrolysis i.e. splitting water into hydrogen and oxygen using electricity from wind turbines. For storage, a new onsite facility will compress the hydrogen into containers on site. Later, the hydrogen will then be used to generate electricity either through an internal combustion engine or via a fuel cell. Xcel and NREL are each paying part of the two million budget for the project. As the project has either started or will start operation in the coming months, we will be closely following this project to examine its cost effectiveness and applicability to California.

The main problem with hydrogen is storage of the gas. If the gas is compressed and stored in a high pressure tank, it requires a lot of energy to do the compression to 5000 PSI and it requires a very large tank to hold a significant amount of hydrogen gas. This significantly lowers the efficiency of the process and makes the hydrogen uneconomical for large amounts of storage. Cooling the gas to very low temperatures will reduce the volume of storage but this makes the process even more uneconomic. New carbon nanotube technology has been proposed as a storage medium for hydrogen and research on this technology is underway. "Carbon nanotubes are microscopic tubes of carbon, two nanometers (billionths of a meter) across, that store hydrogen in microscopic pores on the tubes and within the tube structures. Similar to metal hydrides in their mechanism for storing and releasing hydrogen, the advantage of carbon nanotubes is the amount of hydrogen they are able to store. Carbon nanotubes are capable of storing anywhere from 4.2% to 65% of their own weight in hydrogen."[26]

The US Department of Energy has stated that carbon materials need to have a storage capacity of 6.5% of their own body weight to be practical for transportation uses. Carbon nanotubes and their hydrogen storage capacity are still in the research and development stage. Research on this promising technology has focused on the areas of improving manufacturing techniques and reducing costs as carbon nanotubes move towards commercialization."

DOE is sponsoring a major research project on hydrogen storage technology. The May 8, 2006 DOE press release described a two year DOE sponsored research project to be performed for NREL and XCEL energy to evaluate the use of hydrogen storage in combination with wind generation. The CAISO staff needs to follow up with NREL and DOE to see if we can visit the field test facility and observe the results to date. The field test facility was dedicated in December 2006 so the test should be in progress now. We recommend representatives from the CAISO, the CEC and the California utilities do a joint review of this DOE project.

The CAISO is a participant in a **BPA sponsored research project** on the use of storage technology to mitigate the changes to ACE in the two areas due to wind generation.[27] This is a joint project with Pacific Northwest National Labs (PNNL). The concept is to determine the portion of the Area Control Error in each of the two large control areas that is being driven by the changes in wind generation. Next combine the two ACE terms into a net ACE, and then use high speed storage such as a flywheel system to dampen the change to the two systems. If wind is ramping up in one system and down in the other, the net change may be small and the interconnection frequency is not really being affected by the aggregate change in wind generation energy in the two areas. Obviously there

[26] http://www.fuelcellstore.com/information/hydrogen_storage.html

[27] "Wide-Area Energy Storage and Management System to Balance Intermittent Resources in the Bonneville Power Administration and California ISO Control Areas", BPA 00028087 / PNNL 52946.

are transmission constraints that have to be included in the new control system design. The final report on this concept is due by end of this year.

7.4.2. Compressed air storage

Compressed air storage technology has been used in Iowa with some success. They took advantage of a large underground aquifer for the compressed air storage reservoir. A 1.5 MW wind turbine is used to both compress the air and injected into the aquifer and for recovery of the energy that is feed back into the grid. To make much of a difference, there would have to be fifty or more of these units.

The CEC has contracted with EPRI for a Compressed Air Study for California to determine if the many abandoned gas and/or oil wells in the state could be used for compressed air storage. The report on this study is scheduled for release in August.

7.4.3. Flow batteries

Flow batteries create energy storage by using large tanks of a rechargeable electrolyte. The three types flow batteries are:

- Zinc-bromine
- Vanadium redox that uses sulfuric acid
- Sodium-bromide

Flow batteries have low energy density, but they offer high capacity and independent power and energy ratings. Vanadium Redox Battery (VRB) installations offer up to 500 kW, 10 hrs (5 MWH). In 1991, Meidisha unveiled a 1 MW/4MWH ZnBr battery and numerous multi-kWh ZnBr batteries have been built and tested over the years. So far only relatively small flow battery systems have been installed in the US. The electrolytic material used in these systems is quite corrosive and environmentally challenging to site and permit.

A flow battery system is being proposed for the Santa Rita Jail in California. This project is a partnership with the Jail, PG&E, Chevron Energy Solutions and VRB Power Systems. The objective is to develop a Microgrid demonstration project that includes a VRB flow battery. This project proposal was submitted to DOE for funding in July 2007.

“The proposed Micro Grid Project includes the installation of a 1.5 MW VRB Flow Battery at the Jail with 6 hours of storage capacity for a battery rating of 9 MWH capacity, a Static Transfer switch, and a generation monitoring and control system (e.g. CERTS). This environmentally-friendly Battery, in combination with the existing Fuel Cell and PV systems, will have the capability of following the jail’s electrical load and would provide sufficient generation capacity to provide approximately eight hours of the jail’s full power needs. This will be accomplished without having to start the jail’s diesel generators, thus reducing emissions. The Jail’s peak Utility demand in 2006 was 2.3 MW when the Fuel Cell was not in service. With the Fuel Cell in service, the peak Utility demand would be about 1.3 Megawatts”[28].

The CAISO has agreed to be an advisor on the Santa Rita Jail project if it is funded by DOE.

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[28] VRB project proposal “Santa Rita Jail AC Micro Grid System Demonstration Project Summary - June 21, 2007

7.4.4. Super capacitors

Super capacitors or electrochemical capacitors, possess swift charge and discharge capabilities. More powerful than batteries, they can be cycled tens of thousands of times. Those with energy densities under 20kWh/m3 have been successfully developed, and work is underway to expand the effectiveness of larger units.

7.4.5. Plug in Hybrid Vehicle-to-Grid (PHVG)

The idea of using the batteries of electric vehicles as an energy storage resource -- a concept called Vehicle to Grid (V2G) -- is still in its infancy, but may have potential as a quick-response, high-value service to balance fluctuations in load. By connecting enough vehicles to the grid and transmitting power back and forth as needed, utilities could one day save billions per year, some experts predict.

7.5. Conclusion

The intent of this short report is to highlight some of the current work in progress. The CAISO and the utilities need to work with DOE and the CEC to follow the research in storage technology and to provide opportunities for testing and evaluating new storage technology in California. Storage will play an important role in California in the successful integration of large amounts of renewable energy in the future.

Chapter 8 - National Experience

There have been numerous wind integration studies in U.S. and some common themes have emerged from the published reports. Utilities that have some hydro generation resources can more easily accommodate the variability of wind generation. When the wind generation is high, the hydro systems can be backed down to back room for the wind generation energy. The water is conserved behind the dams and this essentially stores the renewable energy for delivery during times when the wind is not blowing. There are constraints on hydro systems however as a prescribed amount of water release is often mandated for fish, agriculture and environmental reasons. Utilities that depend on the fast ramping hydro systems for regulation lose some of the regulation capability if the units are forced down to minimum energy production levels to make room for the wind generation.

Utilities that have all their units scheduled on a block hourly basis and have a limited amount of regulation capability will also experience some difficulty in handling large amounts of intermittent energy production from wind generation. The combined variability of both load and wind generation can results in major system control problems if they have a limited amount of regulation available and they can not change the scheduled hourly energy production from other generating units. For example, coal fired generating plants do not change production levels easily and typically are not used to supply regulation services. System like ISOs and RTOs with market structures that enable them to redispatch units on a 5 to 15 minute basis will have a much easier time rebalancing their system as wind generation production levels change.

8.1. Major US Studies on Renewables

8.1.1. Minnesota Wind Integration Study – 2006

This study evaluated the reliability and cost impact associated with increasing installed wind generation to 15%, 20% and 25% to serve customer load in Minnesota by the year 2020. Projected increase of wind generation is 4, 500 MW. Four Balancing authorities included in the study – Xcel Energy, Great River Energy, Minnesota Power and Otter Tail Power. The study concluded that they could accommodate up to 25% (5700 MW) of energy from wind generation resources without significant reliability and transmission congestion issues. They will need to increase the amount of regulation capacity by up to 20 MW and their incremental operating reserve costs increase by $0.11 per MWh for the 20% wind generation case. Their total wind integration operating cost range for up to 25% wind energy delivered to their customer is less than $4.50 per MWh of wind generation.

8.1.2. New York State

The state commissioned a study on the impact of 3,300 MW of wind generation (10% of the New York State peak load). The results of this comprehensive study were published in 2005 and the report has been a model for how to do renewable integration studies. GE Energy was the consultant for this study. The results pointed out the importance of interconnection rules that require wind generation to meet Low Voltage Ride Through standards and voltage regulation criteria. The study also highlighted the importance of a reasonably accurate day-ahead wind generation forecast for scheduling of other generation resources and unit commitment. The financial impact of this forecast was very significant (millions of dollars annually) to the customers in NY if no wind generation forecast was available and generating units started that were not needed. The study also showed that the amount of additional regulation capacity needed was less than 40 MW and no additional spinning reserves were needed.

8.2. Western Regional Coordination of Strategies on Renewables

BPA and the ISO have agreed to work together on issues of common interest related to integration of renewables. Particular emphasis is on policy setting with regards to wind development. We already have cooperation and collaboration on technical issues but more needs to be done to shape policy issues on renewables in the west.

Key strategic issues should include sharing of information on generator interconnection queues and forecasted imports and exports of renewables between control areas. This would facilitate improved transmission planning so the energy can be moved between areas with minimum congestion issues.

A second issue is the need for common / consistent interconnection agreement language so wind generators and other renewables will have common treatment in all areas. This working group can create a template for interconnection agreements with wind generation that combines the best features from each company.

8.3. Northwest Wind Integration Action Plan

The Pacific Northwest Wind Integration Plan was published in March 2007. This report was a major collaborative effort of all the Pacific Northwest utilities with BPA one of the leaders of the effort.

A summary of this report follows:

8.3.1. There are no fundamental technical barriers to operating 6,000 megawatts of wind in the Pacific Northwest.

There is a range of estimated costs associated with integrating wind into the Northwest power system. When wind energy is added to a utility system, its natural variability and uncertainty is combined with the natural variability and uncertainty of loads. As a result, there is an increase in the need for system flexibility required to maintain utility system balance and reliability. The cost of wind integration starts low, particularly when integrating with a hydropower system that has substantial flexibility, and then rises as increasing amounts of wind are added. Locating wind resource in geographically diverse areas can help reduce costs. Ultimately, costs plateau at the cost of integrating wind with natural gas power plants.

The preliminary cost estimates for integrating 6000 MW of wind power are based upon existing levels of system flexibility. Load growth and other competing uses for that flexibility, and possible further constraints on system operations will diminish the supply and increase the cost of wind integration services.

With increasing amounts of wind, there will likely be times when large, unexpected changes in wind output (so-called “ramping events”) coincide with periods of limited hydro flexibility. Initial analyses indicate that these will be low probability events, but if other sources of flexibility are not available at the same time, system operators will need to limit wind output for brief periods in order to maintain reliability. The Federal Energy Regulatory Commission now requires wind plant operators to help protect system reliability. Northwest utilities and wind developers are collaborating to implement the requirement in a mutually-satisfactory and cost-effective manner.

8.3.2. Wind energy is providing value to Northwest electricity consumers, but the Northwest will still need other resources to meet peak loads.

The fundamental value of wind to a utility's portfolio is its ability to provide energy to displace fossil fuel consumption, limit exposure to uncertain and volatile fuel prices, and hedge against greenhouse gas control costs. Because wind is primarily an energy resource with relatively little contribution to meeting system peak requirements, the Northwest will need to build other resources with greater capacity value to meet growing peak loads.

8.3.3. In the short term there is available transmission capacity to integrate additional wind resources – but this is not expected to last for long.

New transmission will be needed to support growing loads and resource additions and can help open up new areas for wind development, helping to diversify wind production. This diversity helps smooth variability and therefore lowers the cost of wind integration. Because of the limited contribution of wind to meeting system peak requirements, traditional models for transmission development and marketing should be altered to achieve greater economic efficiency. A more economical and efficient approach for a resource such as wind is to provide a mix of firm, non-firm, and conditional firm transmission that achieves a balance between the cost of transmission capacity and the value of delivered wind energy. Cooperation among transmission planners, regulators, utilities, and the wind development community is essential to create a workable model for planning, financing, and marketing transmission for wind energy.

8.3.4. The major portion of wind integration costs are due to the need for additional flexibility resources to balance loads and resources in real time in order to accommodate wind variability.

Control area operators must have sufficient flexible generating capacity or load management options available to accommodate load and wind variability to ensure that reliable service will be maintained. There should also be provisions for equitable recovery of the associated costs.

8.3.5. There are steps we can take to increase integration capability and to lower integration costs.

The cost of wind integration services can be reduced through generally four types of actions: (1) developing more cooperation between regional utilities to spread the variability of wind more broadly; (2) developing markets that will reward entities who choose to market their surplus flexibility; (3) making more low-cost flexibility such as that provided by hydroelectric resources available; and (4) development and application of new flexibility technologies. Achieving these goals will require coordinated actions similar to those required to establish the Pacific Northwest Coordination Agreement of the Columbia River Treaty. Fortunately, the region has a long history of forging cooperative agreements designed to increase the size of the pie for all regional consumers that can provide a model for what will be needed over the next several years to address wind integration issues.

Chapter 9 - International Experience

The experiences from Europe and other countries with significant amounts of wind generation and other renewables can provide some valuable insights on the issues and solutions that could be adopted in California. Island systems such as Ireland and Australia have greater challenges with larger amounts of wind generation than countries that are part of a large interconnected system like Spain and Germany. The CEC IAP report included a section on “Review of International Experience Integrating Variable Renewable Energy Generation”. This report and additional material from company web sites, presentations at various conference and publish papers are the sources for the material in this section of the CAISO report on Integration of Renewable Resources.

9.1. Spain[29]

While the European countries have led the electric industry with the development of wind, Spain (the second largest wind producer in Europe[30]) has been contending with issues on scale equivalent to the CAISO. In 1996, Spain had 164 MWs of installed wind generation. As of Nov. 2006, there are over 11,000 MWs of installed capacity on a 43,700 MW peak system. By 2010, it is anticipate that there will be over 20,155 MWs on their grid.

The large amount of integration of wind generation caused the Spanish TSO Red Eléctrica de España, S.A. (REE) to develop a strategy the CAISO should consider adopting. The REE strategy is a three prong approach focusing on a sophisticated wind forecasting tools, wind farm connection standards and dispatch-ability of the wind farms.

9.1.1. Spain Forecasting tools

Wind producers in Spain are entitled to deliver electricity to the grid via the wholesale market, or a distributor, as long as it is technically possible. In either case, the wind farms are required to provide a wind forecast to REE. With the large amount of variable wind energy production being placed into the electrical system, a more precise forecasting regimen was required. In 2002, REE started to develop an hourly forecast system that delivering forecast up to 48 hours in advanced. Using data from the wind farms for the various areas throughout the peninsula, REE was able to create and use a high quality forecasting system that can focus on any size region within the country. REE was able to reduce their 48 hour Percent Mean Relative Error from almost 40% in 2005 to around 26% in 2006. For both years, the Percent Mean Relative Error for the less than five hour look ahead is less than 15%. They have achieved these values by applying a continuous improvement process to the forecast system,

9.1.2. Spain Wind Farm Connection Standards

Spain has recognized the potential problem for large amounts of wind integration in regards to stability conditions under system faults.

In accordance with Spain’s technical standards for interconnection, it was mandatory to install three instantaneous minimum voltage relays between the phases in the connection of the wind farm. The relays must provide for instantaneous disconnection of the farm when voltage drops below 85% of the average value between the phases. Studies were carried out to show the importance of

[29] Adapted from “Large integration of wind power: the Spanish experience, Juan M Rodriguez-Garcia, Tomás Dominguez,Juan F, Alonso and Luis Imaz. IEEE PES 2007 Tampa FL

[30] energyBiz August 2007

minimum voltage protection system and system stability. The original studies showed that there was little problem with a short circuit when a small amount of wind production was online but if a short circuit occurred on a day with high wind production, obviously the amount of power disconnecting would be a serious loss of generation which greatly increases the risk to grid integrity.

Looking at this threat to grid integrity, REE undertook a transient stability study of the response of wind energy to fault-caused voltage dips in order to determine the maximum wind production of the Iberian Power System in peak and off peak conditions. The result of the study defined the voltage ride through requirements and the permissible active and reactive consumption values during voltage dip situations.

9.1.3. Dispatchability of the Wind Farms in Spain

REE felt there are two important operational issues that needed to be addressed to guarantee the integrity of the grid because of the large integration of wind. The issues are:

- The current condition and real-time data of the wind facilities and,
- How to coordinate the dispatch the wind generation to match system conditions

REE established a Wind Generation Control Center (WGCC) that was integrated with their Control Center. The WGCC is a 24 hours a day, 7 days a week dedicated desk responsible for collecting and providing the real-time data on the wind facilities to the Control Center and in turn providing the dispatch instruction from the Control Center to the wind farms.

9.2. Germany

Germany currently has over 20 GW[31] of installed wind generation capacity and they expect to have 36 GW installed by 2015[32]. The majority of the wind generation facilities are in northern Germany although they have some wind facilities spread throughout the country. The four German transmission system operators (TSO) must take all the energy produced by the wind generators and they all share the balancing error in accordance to their market share. Therefore the TSO with the largest amount of wind generation capacity does not have to do all the rebalancing of the system based on the wind generation variability in its area.

Wind power forecasts are essential to their operation. They forecast wind energy production 72 hours in advance for setting up their energy schedules and then use short term forecasts up to 8 hours in advance to real time operating decisions. The TSO are communicating the data from the wind generation facilities every 15 minutes and updating the 72 hour wind generation forecast twice a day. They do not receive data from all the wind farms so they use modeling and scaling methods to fill in the missing data.

Germany does not use "Net Metering" such as we use in the U.S. for wind generation that is installed on the grid. This means they separately meter the energy production from wind generation and they pay a premium for renewable energy that fits the load profile. The price differential between what load is charged what the generation from renewables is paid may be as significantly different. For example, load may be charged 10 cents per kWh and wind generation paid as much as 40 cent per kWh if the wind energy production is coincident with the peak load period. "The German

[31] CEC PIER Project Report, April 2007, "Review of International Experience Integrating Variable Renewable Energy Generation", page 1

[32] "Integrating Wind Energy into Public Power Supply Systems – Germany State of the Art" by Reinhard Mackensen, Bernhard Lange, Florian Schlogl; Institut fur Solare Energieversorgungstechnik e.V.

Renewable Energies Act grants a fixed feed-in tariff for each kWh produced by Renewable Energy Sources"[(4)].

9.3. Ireland

As of June 2005, ESB National Grid for Ireland had 383 MW of wind generation connected to the grid and 575 MW of additional wind generation planned. Ireland is an island system and they can not lean on a large interconnected grid to help them with the integration of large amounts of wind generation. To ensure they can continue to operate the grid reliably, they have performed in-depth studies on the impact of large amounts of wind generation on their system. In July 2004, they published their interconnection standard document WFPS1 (Wind Farm Power Station Grid Code Provisions). This document describes their low voltage ride through, voltage control and frequency response requirements. They are particularly concerned with frequency issues and how to limit ramp changes from wind farms. They also recognize that wind generation is an intermittent resource and can not be counted on to meet peak load demands. They have therefore concluded that they need an additional 85 MW of fossil fueled generation (operating reserves) for every 100 MW of wind generation to ensure they have sufficient generation to meet their load. Ireland therefore represents one extreme in the issues associated with integration of large amounts of wind generation on the grid.

9.4. Denmark

Denmark currently has over 2,000 MW of installed wind generation capacity and its goal is to increase the amount of wind generation to 5,500 MW which is equivalent to 50% of the total electric demand for Denmark. Most of the current generation capacity is from small units that are less than 1 MW each and they are widely distributed through the country with the largest concentration in Western Denmark. Many of the wind generators are connected to the distribution system rather than the transmission grid. Their goal is replace many of these small turbines with new larger units over the next five years. The reason Denmark can handle such a large amount of wind generation is due to its transmission ties to Norway, Sweden and Germany. Hydro system in the Nordel Pool provides much of regulation required and operating reserves to Denmark. The 15 minute variability of the wind generation production is also relatively small, approximately 8 %, and this enables them to forecast and schedule wind energy on an hourly basis. The one lesson learned from Denmark is the value of have strong ties to neighboring areas, especially ones with lots of hydro generation, to mitigate the intermittence of energy production from large amounts of wind generation.

9.5. Canada

9.5.1. BC Hydro

BC Hydro currently has 11,000 MW of generating capacity of which 90% is from hydro generation. It does not currently have any installed wind generation capacity but BCTC currently has 700 MW of wind generation in its interconnection queue. The northwestern coast area of British Columbia is an area with lots of potential wind generation but BCTC will have to build some major new transmission to this area before it can be developed. The long range energy plan for the Province is to develop wind generation to meet its load growth and to export significant quantities of the renewable energy to the western area of the U.S., especially California.

9.5.2. Ontario's Independent Electricity System Operator (IESO)

IESO currently has 400 MW of installed wind generation capacity. IESC commissioned a wind integration study by AWS and GE to assess the impact of 1300 MW of wind generation on their system. Their study concluded that Ontario has significant wind generation potential and it could provide more energy in the winter than in the summer. Wind generation forecasting is critical for reliable operations and the amount of installed wind generation capacity increases. They also concluded they can handle up to 5,000 MW of wind generation without a serious impact on their operations. This is on a system with 33,100 MW of installed generation capacity of which 23% is hydro which gives them the needed operational flexibility. They also do extensive interconnection analysis for each proposed wind generator to verify the voltage control and transient stability requirements and the potential need for a Special Protection Scheme.

9.5.3. Manitoba Hydro (Manitoba)

Manitoba is a predominately hydro generation system with over 5,000 MW of hydro generation capability. As a 95% hydro system, they can use the hydro resources to store wind generation production in off-peak periods and then deliver it at on-peak periods. They currently have less than 100 MW of wind generation but expect to add 300 MW in the next several years. They calculate their wind integration cost at between 0.5¢/kWh and 0.6¢/kWh. Their business strategy is to export most of this wind generation to U.S. utilities in the Midwest that need to buy renewable energy to meet their state's RPS goals. Manitoba's strategy clearly shows the value of hydro generation resources for storing and shaping an intermittent resource such as wind generation and delivering to meet daily peak loads.

9.5.4. Alberta Electric System Operator (AESO)

AESO has 443 MW of wind generation out of 13,223 of installed generation capacity. 81 % is gas or coal fired units with only 899 MW of hydro generation. They have established a 900 MW ceiling for wind generation at this time but have applications for 3800 MW of new wind generation capacity. They have elected to limit the amount of wind generation until they have completed additional studies on the impact of large amounts of wind generation on their system. They are concerned about how their system will be able to meet the large ramps typically associated with large amounts of wind generation. They also have some major transmission planning work to do to move the renewable energy from the generation sites to the load centers.

9.5.5. Hydro Quebec

Hydro Quebec's generation resources are 92% hydro (32,000 MW) with wind generation of 322 MW. Obviously with this much hydro generation, the intermittence of wind generation is not an issue. Hydro Quebec's goal is to have 4,000 MW of wind generation installed by 2015 and then to maintain a 10% wind / hydro generation ratio. They are concerned that their traditional hydro schedules to serve their load will have to change. They are focused on better forecasting tools and improved modeling of the wind generation facilities.

9.6. Conclusions

There are significant lessons that can be learned and strategies adopted from these other international transmission operators. We need to learn more about Germany's technique for sharing the system balancing requirement between the four TSOs. Spain has made significant progress in forecasting their wind energy production and has implemented strict interconnection rules. Ireland has implemented ramp limits to mitigate the problem with large ramps from wind generation resources. Canadian utilities have the advantage of having significant hydro generation resources that will reduce their integration problems and we should use some of their tools and strategies where feasible.

Chapter 10 – Conclusions and Recommendations by Task

Task 1. Develop new Ramp Forecasting and planning tool for real time operations

The output from wind and solar generation can change dramatically, both up or down, in a very short period of time. These rapid changes pose a significant challenge to system reliability and to the grid operator who must meet NERC and WECC Reliability Performance Standards. Better forecasting and planning mechanisms, especially on a micro-climate basis, will enable the CAISO to mitigate the operational problems that otherwise arise from rapid swings in generation or load, both up and down. The purpose of this task is to use that information and the answers to the questions below to develop a new ramp forecasting and ramp planning tool for real time operations. The goal is to have a prototype of the tool ready in 2008 for testing and evaluation. The production version of the tool must be ready in 2009 to coincide with the expansion of the amount of wind and solar generation installed on the system.

Key questions are:

1. How to accurately forecast ramps? What are the best-forecast sources and what meteorological data is required? Does Weather Bank provide sufficient forecast information with sufficient geographical granularity or do we need additional data and another forecasting service?

2. Do we need to have a person “on shift” that is assessing weather patterns and forecasting ramps due to intermittent renewable resources?

3. Do we need a Doppler radar system in major wind-generation areas (e.g., Tehachapi) to see approaching weather fronts? Would SODAR be more cost effective? What has been the experience of others detecting major weather fronts?

4. Who needs the ramp data – Real time operations? SC’s? Wind Generator Operators? Others?

5. How far in advance do we need to forecast ramps? A few hours? Day-Ahead?

6. How should the ramp information be made available to Real-Time operations? Impact on EMS? PI Displays? Other?

7. What are the specifications for a Ramp Planning Tool to assist the Operators in anticipating the dispatch notices that will be required to either start Quick-Start units or to shut down units?

Task 1.1. Ramp Mitigation Strategies

What are the optimum strategies for mitigating large ramps? Not all ramps are bad. A ramp up of solar energy in the morning period when the wind generation energy is ramping down could result in a net ramp that is very manageable. Ramps up of energy production during the morning “load pull” could be very helpful. So an important consideration is which periods of the year and which hours during the day do we need to take action to mitigate a large ramp up or large ramp down?

Key questions are:

1. What are the criteria for initiating ramp mitigation actions?

2. Some control areas ask wind generators to limit their "ramp up" production to a specific number of megawatts/minute. Is this a practical strategy? Could that strategy also be applied in the downward direction by advance curtailment of wind generation in anticipation of the decreasing wind so that a sudden downward ramp could be avoided? How would we decide what is the ramp limit? How would this information be sent to the wind generator operators? How would the ramp limits be allocated between all the different wind farms?

3. Is there a transmission limitation criterion that should also be considered such that we would have a different limitation for various areas of the system (e.g., SP 15 versus NP 15, areas west of Devers, south of Tehachapi, etc.) and what would be the justification for this difference?

   - Are there other strategies that could be used to mitigate the impact of ramps? Use of hydro resources, pump storage, or other types of storage to rapidly ramp up or down for smoothing the ACE? Should we pursue the use of mid-hour intertie schedule changes? Should these be translated into one or more Market Products?

4. What will the dispatch notices look like for the other generators if we do not have a ramp mitigation strategy and what is their expected response?

Task 2. Over Generation Problems

This Report describes the Over Generation Problem in some detail. Wind Generation areas such as the Tehachapi characteristically produce maximum energy at night when loads are low. In the spring, when California has maximum hydro generation conditions due to snow melt in the Sierra, the wind generation production is often at its maximum. This results in a serious over generation condition even with the limited amount of wind generation currently installed in our area. As the amount of installed wind generation capacity rapidly increases in the next several years, the over generation problem will grow. The purpose of this task is to review our existing procedure for handling over generation conditions and determine if it needs to be modified to implement pro-rata cuts for wind generation production.

Key questions are:

1. Does procurement of additional regulation solve the problem?

2. Do we have accurate P_{min} numbers for all generation resources?

3. How many megawatts of "Must Take" generation do we have on the system?

4. If we send dispatch notices to wind generators to curtail some production, what is the time lag we should expect between the sending of the notice and the reduction of wind generation production?

5. Are there operators at the wind plants on a 24x7 basis to respond to the dispatch notices?

6. Is the estimated amount of wind generation curtailment (800 MW for less than 100 hours per year) accurate and what are the consequences for doing these pro-rata cuts?

7. How much of the problem is solved by the new market system?

Task 3. Improve accuracy of Day-Ahead Energy Forecasts for wind generators

The CAISO needs accurate Day-Ahead forecasts on the amount of wind generation energy production that can be expected for each hour of the next day. This information is an essential component in the decisions about procurement of not only resources to meet demand, but also Operating Reserves and Regulation Resources, as well as the dispatch notices for generator start-up. Previous studies (NYISO) have shown that savings of $100 Million dollars a year are possible by having a reasonably accurate day-ahead forecast of wind generation energy production. The purpose of this task is to procure a wind generation forecasting service that can provide the most accurate forecasts possible for use in the MRTU Day-Ahead market.

Task 3.1. Access the accuracy of current day-ahead forecasting technology.

Review the accuracy of the day-ahead forecasts supplied by AWS Truewind for each of the wind generation areas. Review the accuracy of day-ahead forecasts for other control areas such as ERCOT in Texas, NYISO and BPA. Review the accuracy and adequacy of the metrological data for each of the wind parks. Assess whether the forecast data or the forecast models or both are the source for any inaccuracies in the day-ahead wind energy forecast for each wind park.

Task 3.2. Research new day-ahead forecasting tools

Review the CEC sponsored research work that was published by in June 2006. EPRI, AWS True Wind and UC Davis performed this work. They explored the accuracy of different types of wind generation forecasting models. The results of this work need to be fully reviewed. The preliminary conclusion was that the research team had made a significant break through in improving the accuracy of 5-7 hour-ahead forecasts and of day-ahead forecasts. Additional work is needed to validate the results with a prototype-forecasting tool. The results from this task are to produce a set of recommendations for the scope of work for any additional research that is needed so they can create a final specification for a commercial grade day-ahead forecasting tool.

Task 3.3. Acquisition of a Day-Ahead Forecasts

Develop a Request for Proposal for a day-ahead wind generation forecasting service. The forecast should include total energy production from all wind generation facilities and the forecasted energy production wind generation areas. The ideal forecast would also have a breakdown by generators in the PIRP program. If the decision is to use two or more forecasting services, then the recommendation must include the expected benefit of using more than one supplier and how the multiple forecasts should be combined into a final forecast for the MRTU Day-Ahead market.

Task 4. mprove accuracy of Same Day Energy Forecasts for wind generators

MRTU will require the PIRP generators to enter their forecasted energy in the Hour-Ahead Scheduling Process (HASP). Today's PIRP wind generation scheduling process requires a wind generation forecast nearly 3 hours in advance of the real-time operating hour. Under the MRTU HASP program, the time frame is shortened to 75 minutes before the start of the real-time operating hour. This much shorter lead time means that an advanced persistence forecasting program may be as accurate if not more accurate than other more sophisticated forecasting models such as neural network programs. The purpose of this task is to explore all options for improving the same day hourly forecasts for both PIRP and non-PIRP wind generators and if the PIRP program should changed under MRTU. If the program is to be changed, then this will probably require a tariff filing.

Key questions are:

1. If a persistence model is the best option for 75 minute forecasts/schedules, should the wind generators do their own forecasting? Do we need a commercial forecasting service going forward or could we do the forecasts our selves?

2. How much in advance of the HASP scheduling point do the SC's for the wind generators need for forecasted energy production to sell the uncommitted energy? Is this an issue?

3. The CAISO needs a 5-hour forecast which is used to make market and reliability decisions on dispatch instructions to quick start units. Obviously if the energy from wind generators is going to be below the original day-ahead forecast and energy schedule, we will need additional energy in the operating hour. If there are insufficient reserves and supplemental energy available to fill in the deficient, then the ISO must call upon quick start units to start up and provide the needed energy. If there is an excess of energy forecasted, then there is still time for SC's to find buyers for the excess energy and set up the exports for the real-time operating hour. The ISO will also have sufficient time to look ahead and plan alternate strategies for the real-time operating hour. Does this argue for retention of a commercial forecasting service as persistence forecasts can not provide an accurate 5 hour forecast?

4. Should we use the same forecasting tools for this 5-Hour-Ahead forecast as we used for the day-ahead forecast or do we need a different tool?

5. What are the operational and maintenance related concerns for maintaining two forecast tools? So do we maintain two separate forecasting tools and, if so, when should we switch from one to the other?

Task 5. Develop new graphical displays for Real-Time Operators so they can anticipate Wind Generation Forecasted Production

PI displays can tell the operators what wind generation energy production is at that moment but they do not include the forecast of what wind is going to do in the next new minutes or hours. With forecasts for five or more wind park areas, there is both local data and aggregate data. The aggregate data and ramp forecasting data impact the generation dispatcher the most. The transmission dispatcher is more affected by the local generation and the amount of energy that will flow on the transmission networks. The CEC has offered to fund some research work on this question so this task may involve developing a detailed scope of work to secure the funding. They may identify some experts / consultants that could help us research and prototype the best man/machine interface for display of this information for the operators. The purpose of this task is to develop prototype displays for real-time operations that show actual energy production and forecasted energy production of wind generation.

Key questions are:

1. How far in advance does the forecasted energy production need to be for the operators? Minutes? 15 minutes? 1 hour? 2 hours? 5 hours?

2. How should the wind generation forecasted production information be supplied to the Real-Time operating personnel?

3. Do we need graphical displays and if so, how should these displays look?

4. Is it important to see weather data for these areas as well as the actual energy production and forecasted production?

5. What decisions are affected by knowing the forecasted energy production?

Task 6. Link renewables forecasting with MRTU

Once the day-ahead and same day forecasting tools have been validated, the next question is how to link this information with MRTU. We know the forecasted wind generation will be a key ingredient for the RUC process. The purpose of this task is to document the information flow process should and test how it will be used in the RUC process.

Key questions are:

1. How should the forecast information be provided and who will use it?

2. Will the forecast information be used by the SC's for day-ahead schedules?

3. Which MRTU systems will be affected if any?

4. What is the flow of information, what decisions will result, and how will the information be used in settlements?

5. What reports will need to be generated?

Task 7. Scheduling / Managing Imports and Exports of Renewables

California may not have enough locations for new wind generation and other renewable resource within the state for the IOU's to meet their RPS obligation. The IOU's are considering imports of wind generation from Oregon, Nevada, and other western states. The purpose of this task is to establish the rules and procedures for facilitating these imports.

Key questions are:

1. Should imports of intermittent resources they be dynamically scheduled?

2. Who will have the obligation for shaping and firming?

3. Are there limitations on how much intermittent energy that we can accept? Is the amount of regulation in southern California one of these limitations?

4. Is there anything special we should do for scheduling and tagging imports and exports of renewables?

5. Should the tolerance band be changed for dynamic schedules?

6. Should we request the sending control area to share some of the regulation burden?

7. Should the SC that is buying the non-shaped energy be charged for the additional regulation burden? If so, how do we determine the associated cost?

During periods where the ISO has over generation conditions, we are definitely interested in exporting some of this excess energy. Whatever rules and procedures we impose for imports will probably apply for our exports so we need to make sure we have not imposed some unfair burdens on imports and exports.

Task 8. Impact on Resource Adequacy

Develop new models and scenarios to determine the "best fit" generation portfolio for integration of large amounts of renewables. How many MWs of short start units will be required? What additional generation and storage facilities will be needed? How can this information be shaped to help guide the CPUC RA requirements?

Task 9. Modeling of Wind Generation Facilities

The current Load Flow and Transient stability models stop at the point of interconnection of the wind farm. The actual performance of the wind generators and the sub-transmission collector systems is ignored. Other countries such as Ireland have found it essential to include actual models of the wind generators in their power system studies. The CAISO requested the CEC fund a new R&D study that improves the modeling of these facilities. This project has been approved and the kickoff meeting was held in august 2007. The purpose of this task is to recognize the commitment of CAISO resources to the technical and project advisory groups for this R&D project. The results will be new models that can be used in the transmission planning tools such as transient stability programs.

Task 10. Changes to PIRP II for Hour-Ahead forecasting and scheduling

Add solar generation resources in PIRP. Develop new forecasting models for concentrated solar resources so they can be included in the PIRP program.

Glossary of Terms

HASP – Hour-Ahead Scheduling Process

IFM – Integrated Forward Market

LVRT – Low Voltage Ride Through

MRTU – Market Redesign and Technology Upgrade

SVC – Static Voltage Compensation

RTEC – Real Time Economic Dispatch

SCUC – Security Constraint Unit Commitment

STUC – Short Term Unit Commitment

RTUC – Real Time Unit Commitment

Appendices

Appendix A. – Study Results - ***Load Following Capacity, Ramp Rate and Ramp Duration***
Appendix B. – Study Methodology
Appendix C. – Load Forecasting Error Analysis
Appendix D. – Wind generation forecasting for 2010
Appendix E. – Wind forecasting error
Appendix F. – Wind Generation Turbine Modeling
Appendix G. – Tehachapi Transmission Plan

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1. CPUC Report, November 1, 2005 "Achieving a 33% Renewable Energy Target", by The Center for Resource Solutions Team

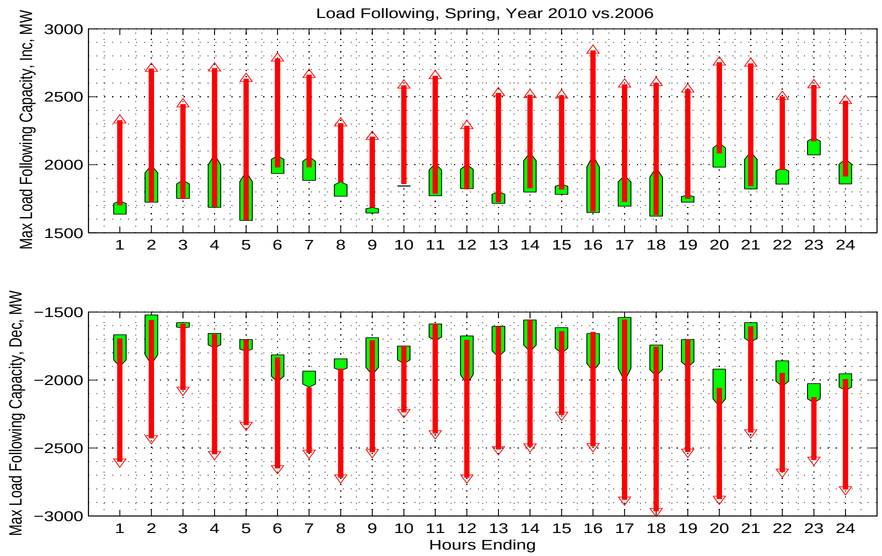
2. CEC PIER August 15, 2006 workshop on Intermittency Analysis Project: 2010 - "1_YEN-NAKAFUJI_PORTER_2006-08-15.pdf"

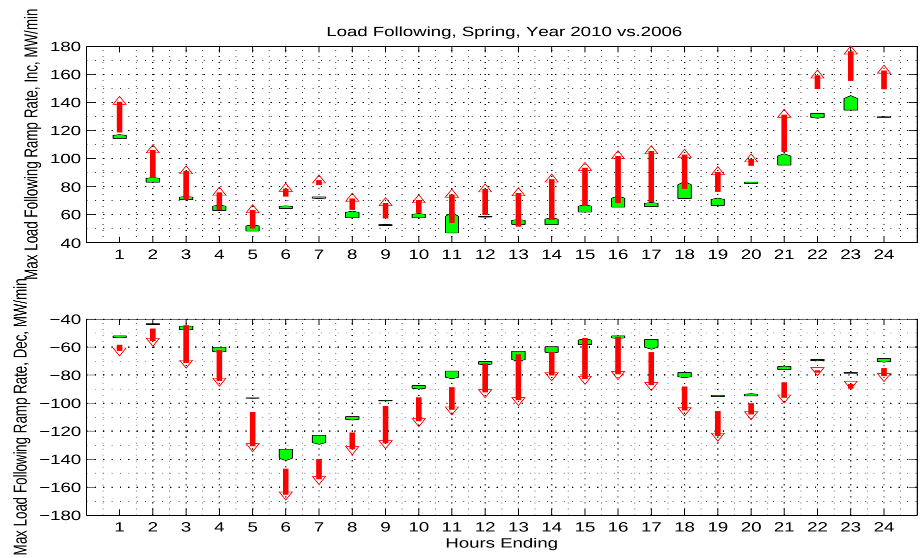
3. "Impact of Past, Present and Future Wind Turbine Technologies on Transmission System Operation and Performance" CEC PIER Project Report; May 2006 CEC-500-2006-050

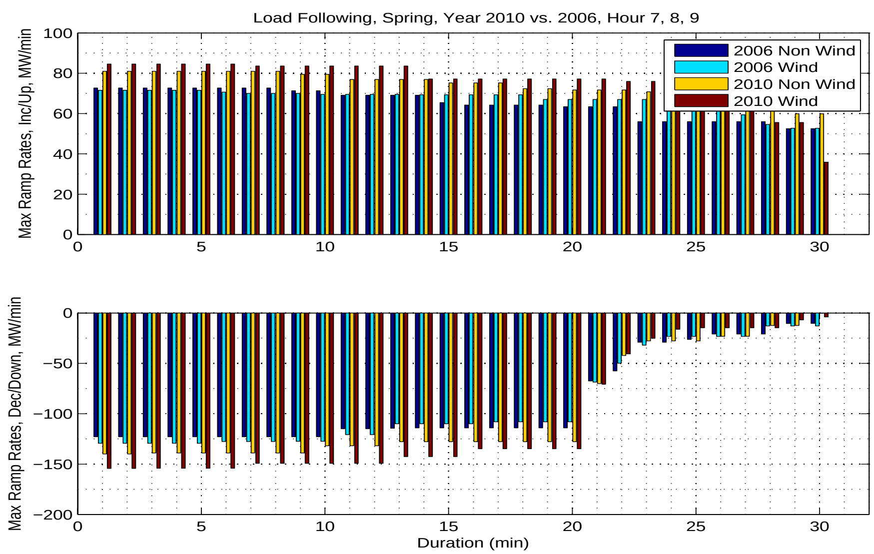
Appendix A – Study Results

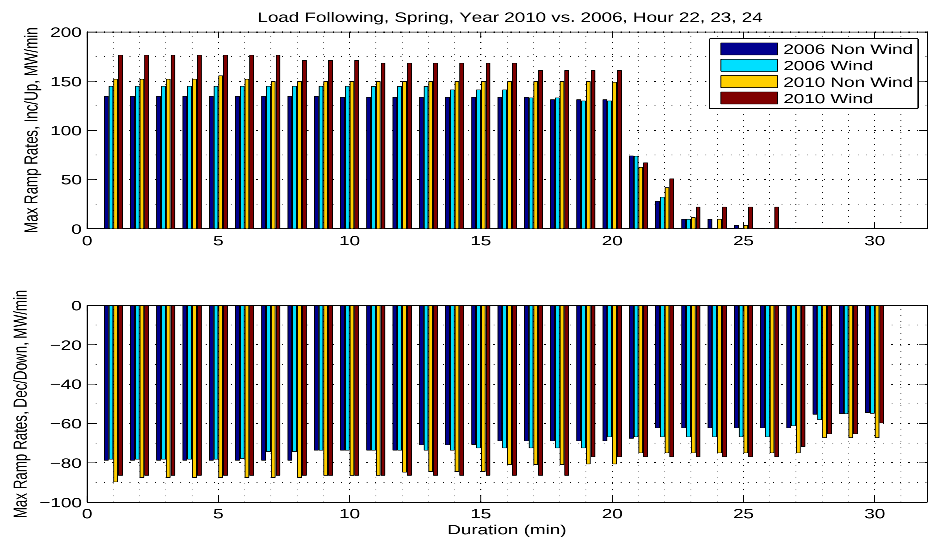
Spring: Load Following Capacity, Ramp Rate and Ramp Duration

The Green arrow represents 2006. The Red arrow shows 2010 increase due to wind only. The tail of the arrows corresponds to no-wind.









Spring: ***Regulation Capacity, Ramp Rate and Ramp Duration***

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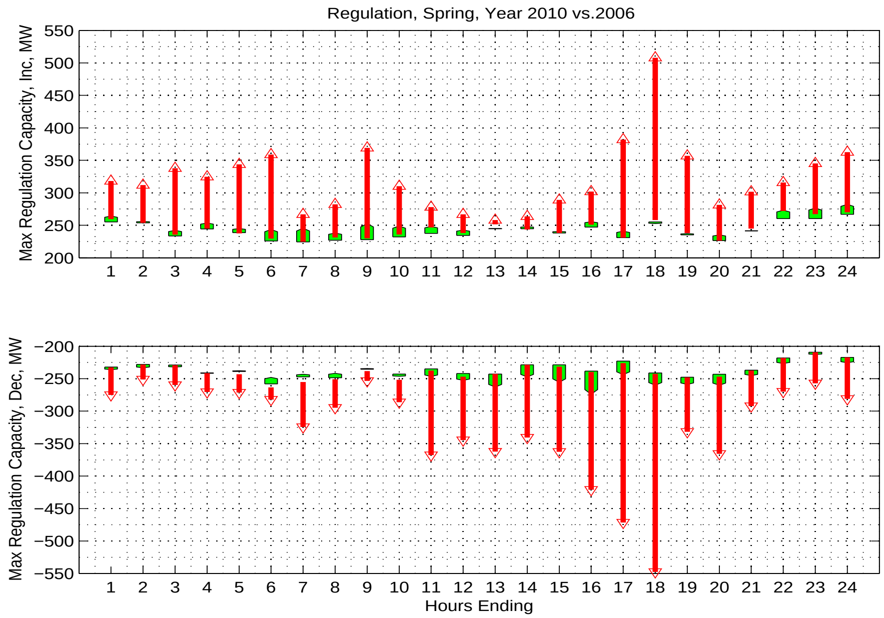

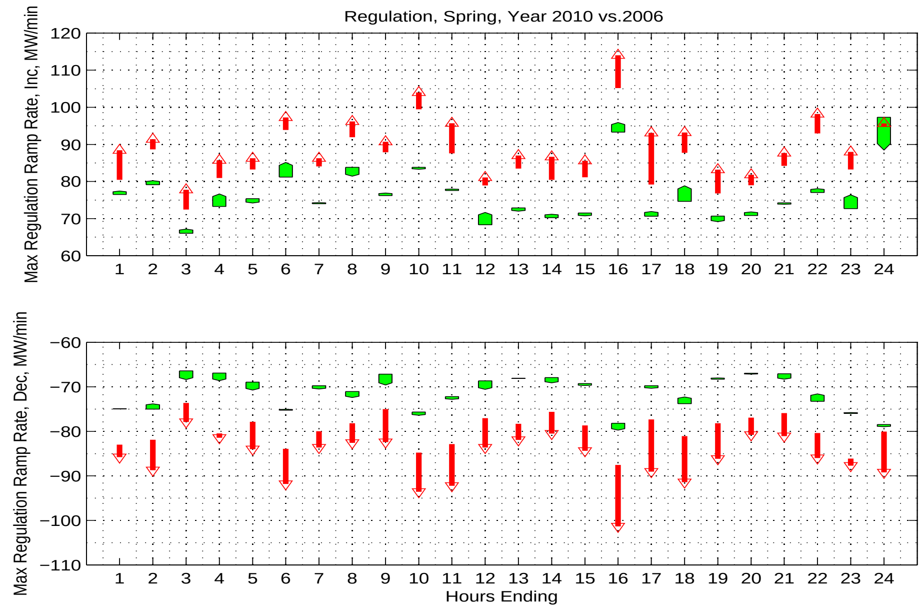

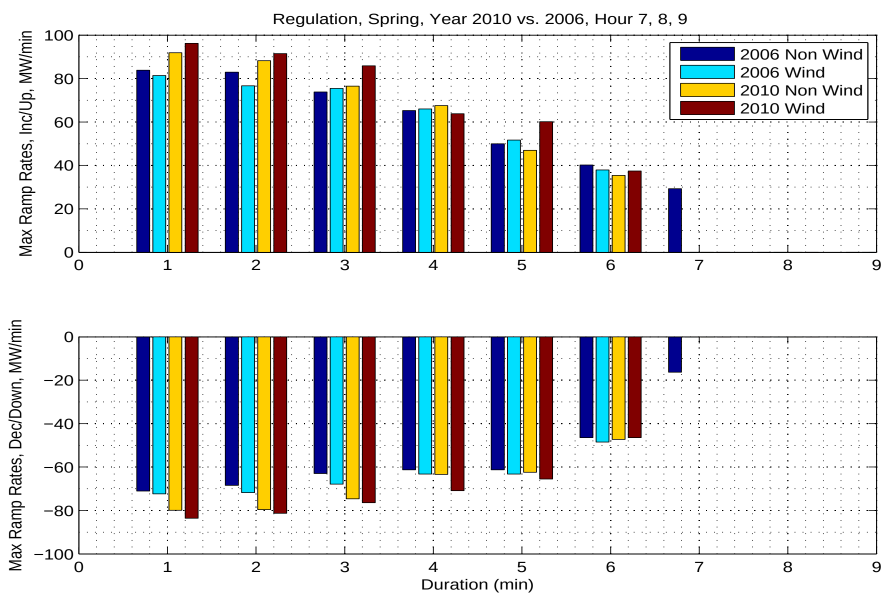

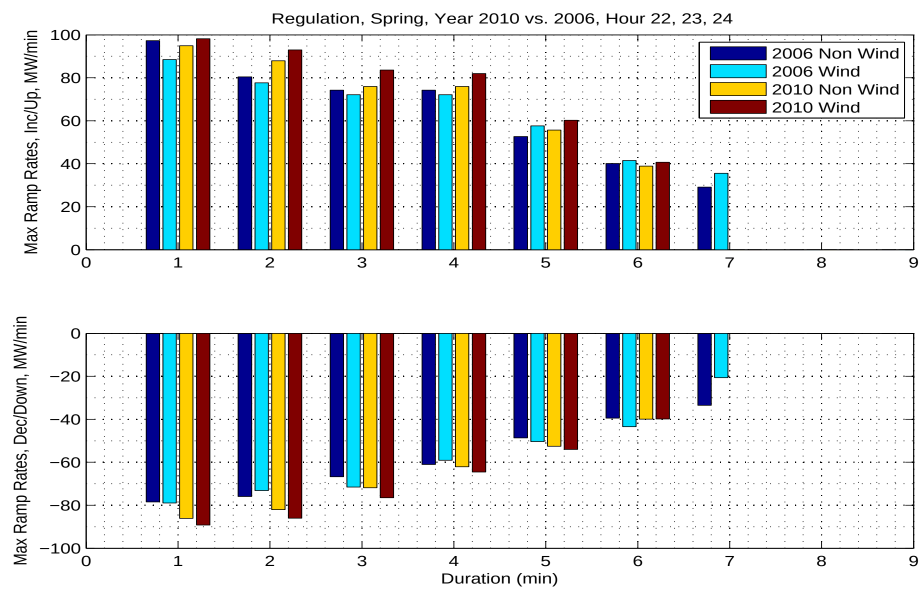

Summer: Load Following Capacity, Ramp Rate and Ramp Duration

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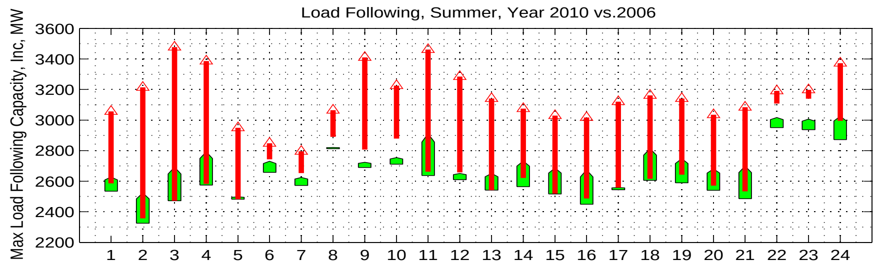

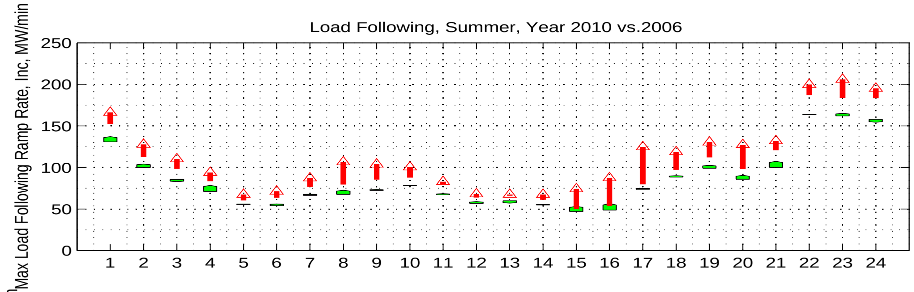

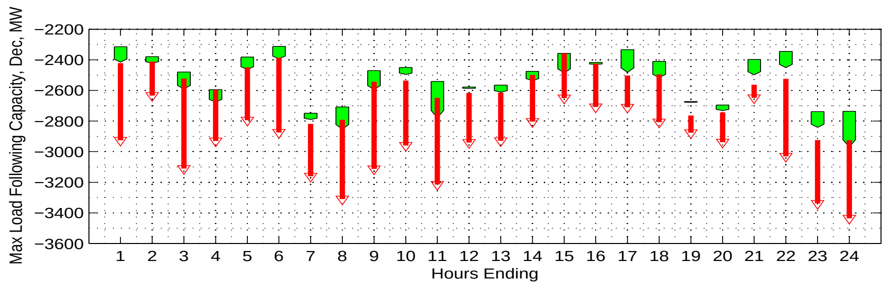

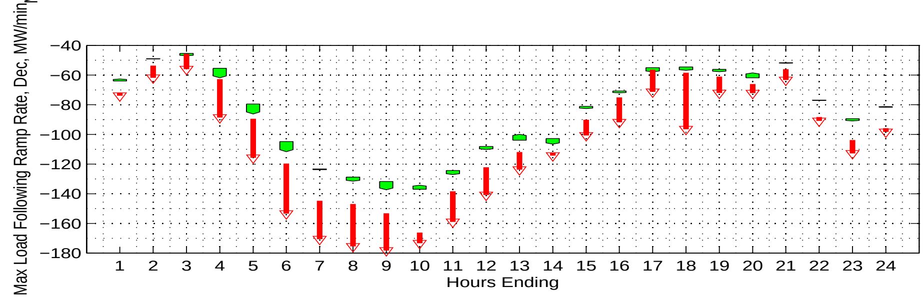

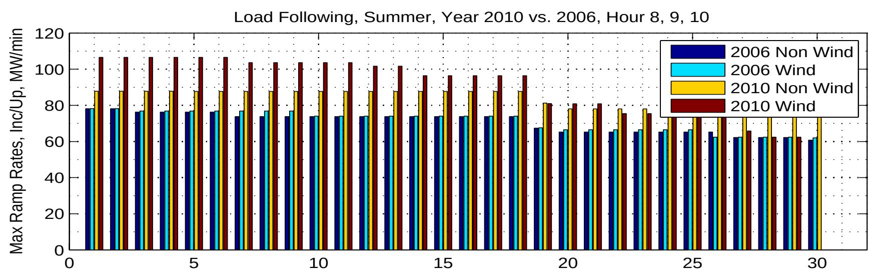

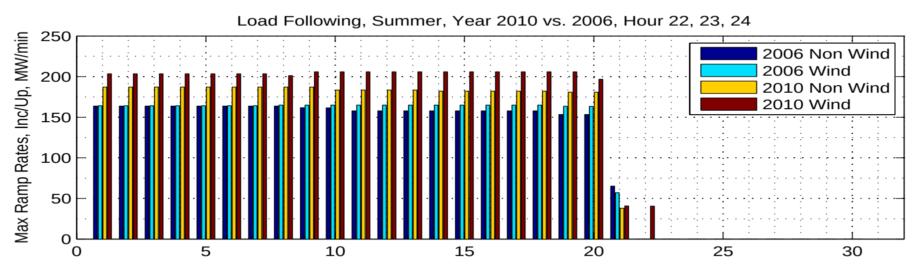

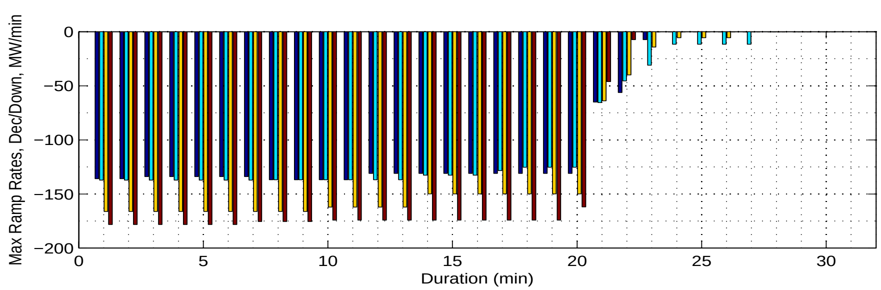

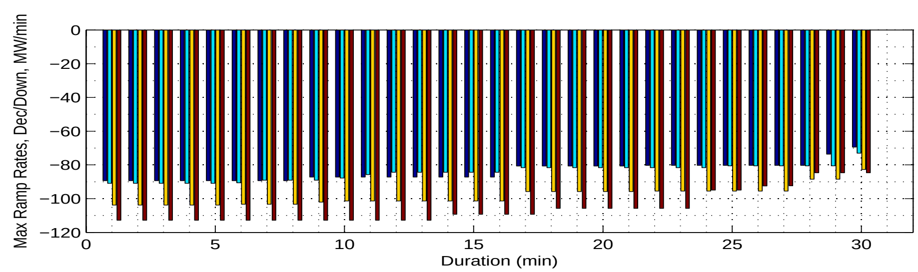

Summer: Regulation Capacity, Ramp Rate and Ramp Duration

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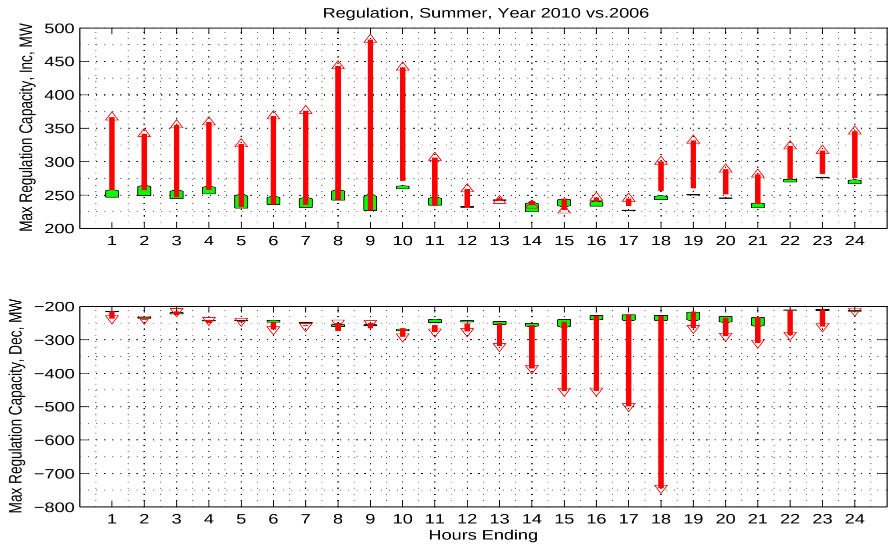

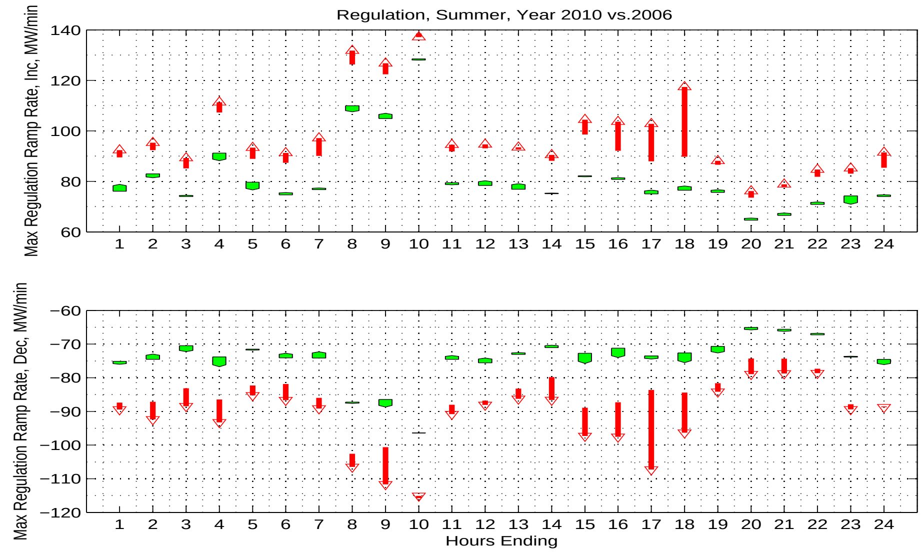

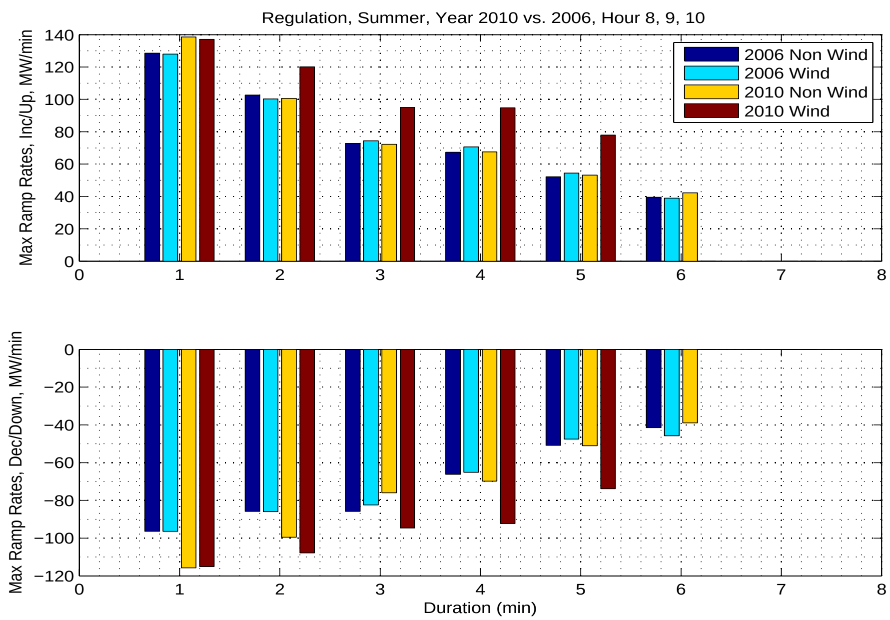

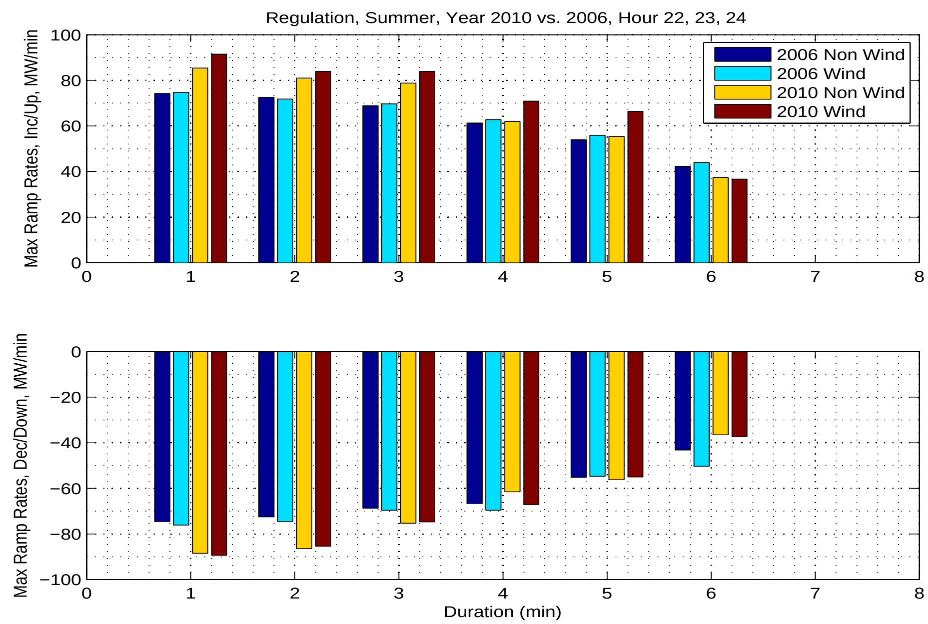

Fall: Load Following Capacity, Ramp Rate and Ramp Duration

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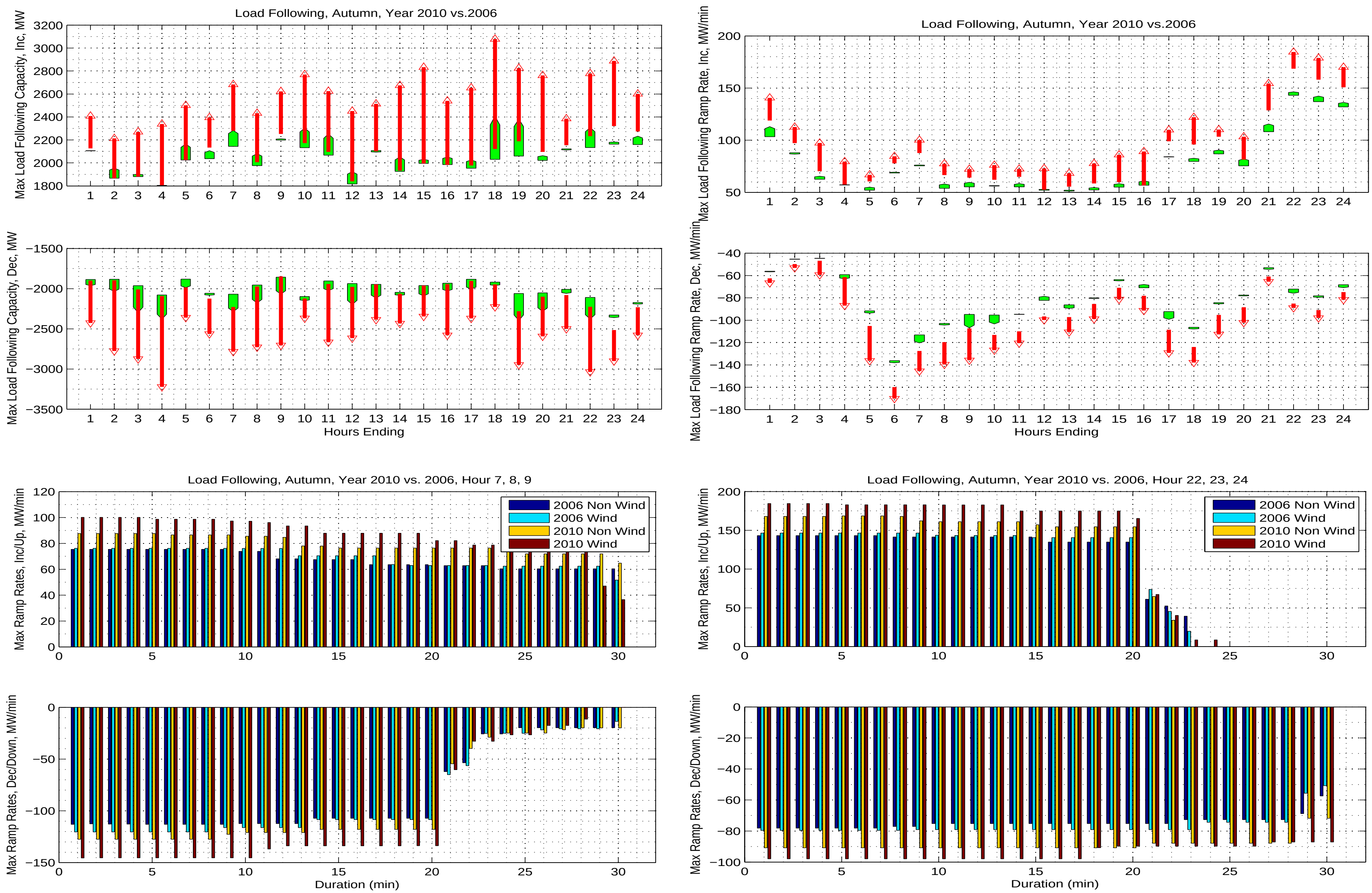
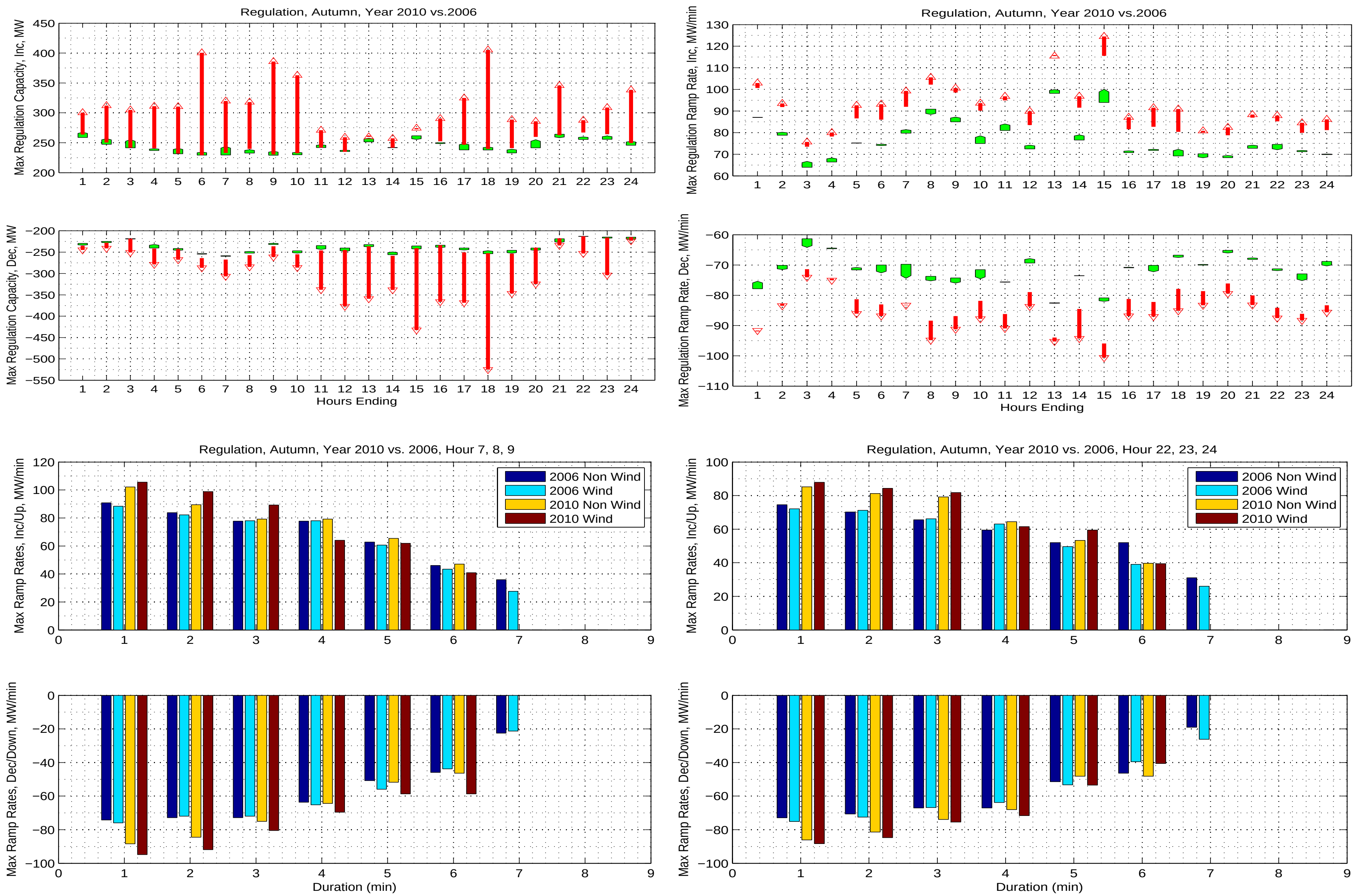


Fall: *Regulation Capacity, Ramp Rate and Ramp Duration*

The Green arrow represents 2006. The Red arrow shows 2010 increase due to wind only. The tail of the arrows corresponds to no-wind.



Winter: Load Following Capacity, Ramp Rate and Ramp Duration

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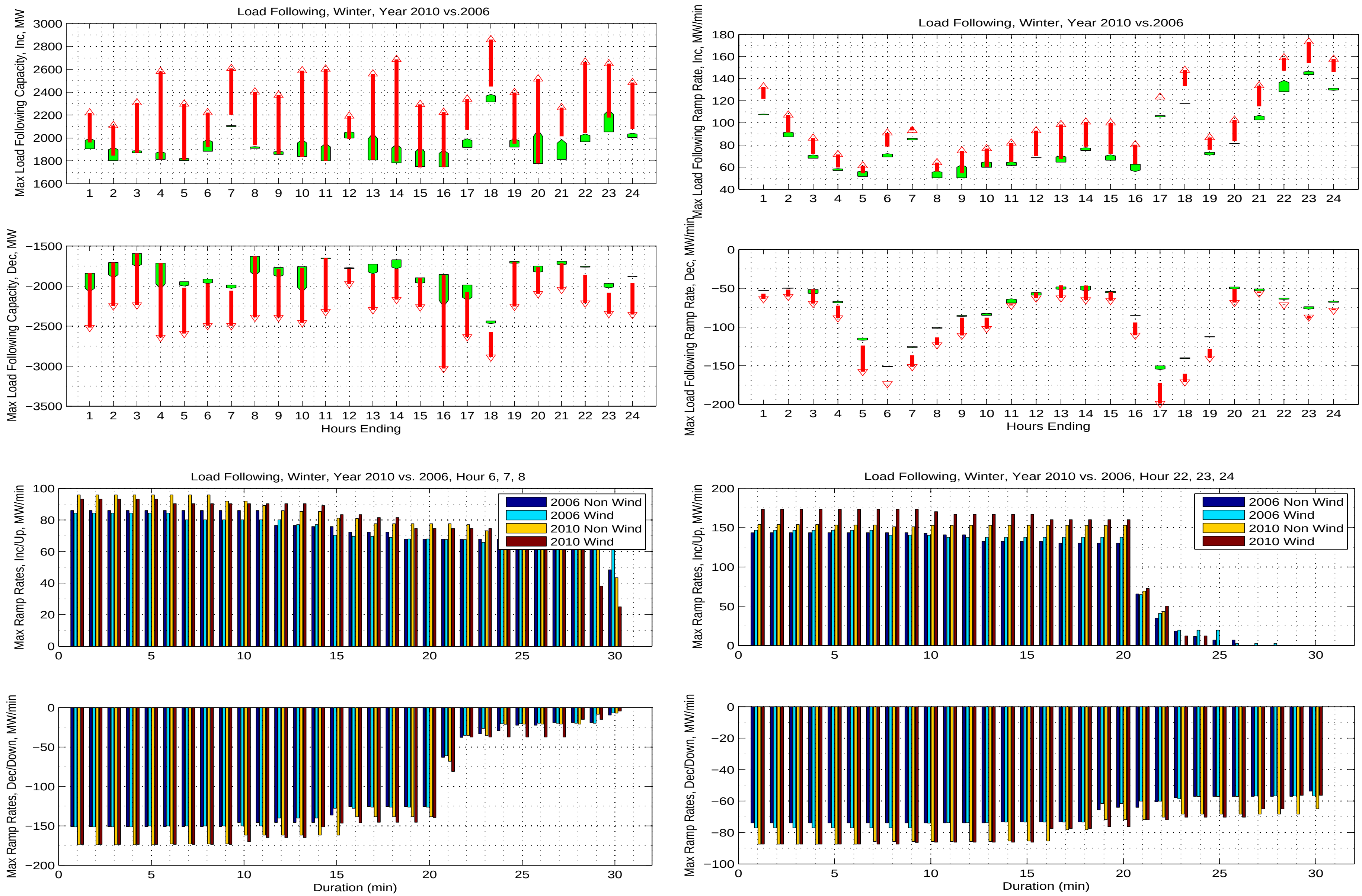

Winter: Regulation Capacity, Ramp Rate and Ramp Duration

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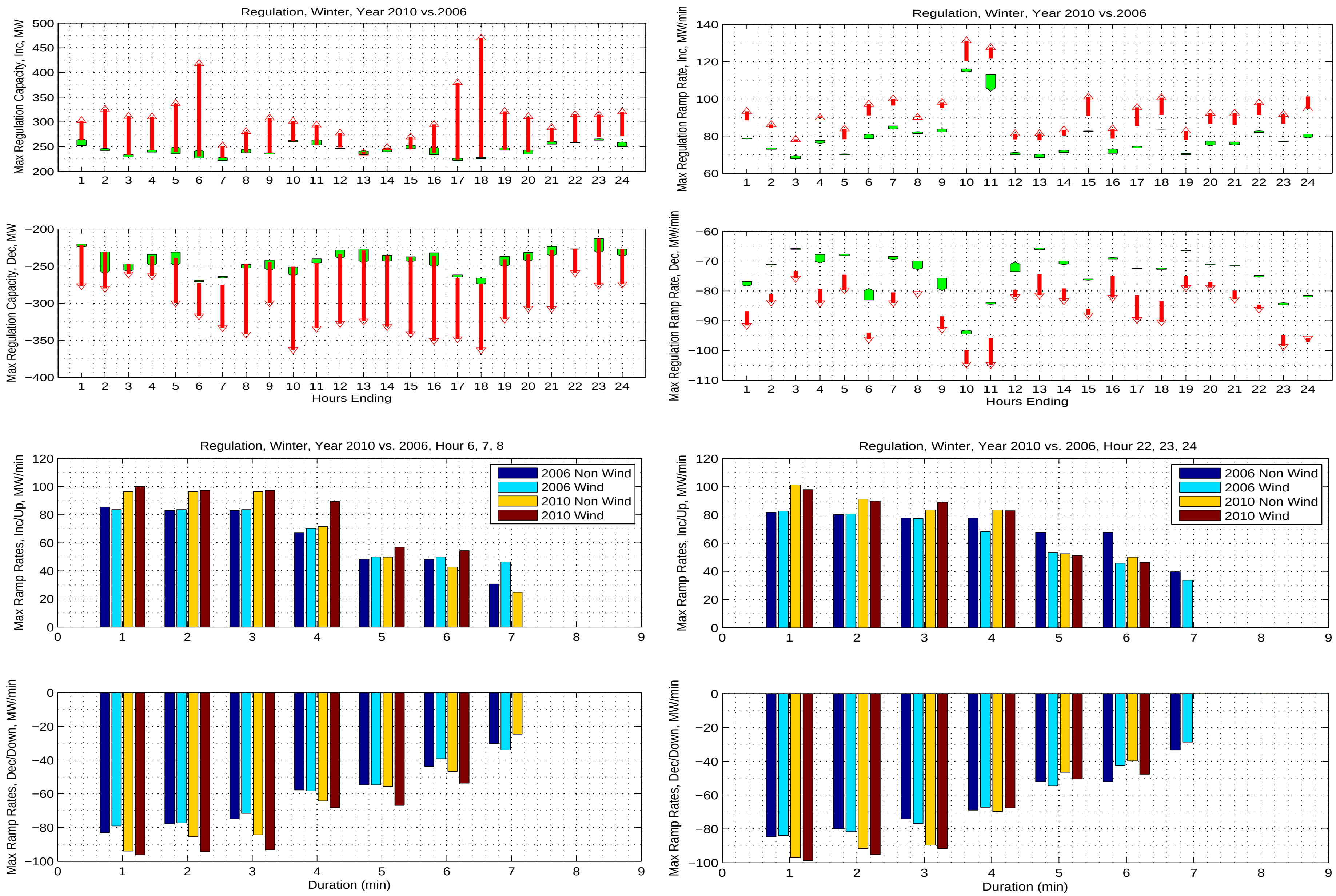

Appendix B --- Study Methodology

Methodology to Evaluate the Impacts of Wind Generation on CAISO's Regulation and Load Following Requirements Under MRTU

Clyde Loutan (CAISO Project Lead), Phillip de Mello (CAISO/University of California - Davis),
and
Yuri Makarov (Principal Consultant, Battelle), Jian Ma (Battelle/University of Queensland), Shuai Lu, (Battelle)

1. Assumptions

1.1. Impacts of wind generation on the interconnection frequency are neglected

1.2. Within the studied future periods, Hour Ahead hourly energy forecasts for all wind generation regions will be available at the CAISO.

1.3. The Hour Ahead load and wind generation energy forecasts are provided at latest 120 minutes before the actual beginning of an operating hour.

1.4. The Real Time five-minute load forecasts are provided 7.5 minutes before the actual beginning of a five-minute dispatch interval (or 10 minutes before the middle point of this interval).

1.5. The load forecast errors are unbiased (i.e., they have negligible average).

1.6. The load and wind forecast errors are random variables distributed according the truncated normal distribution with certain autocorrelation between the subsequent forecast errors.

1.7. The MW load forecast error will have the same distribution in 2010 as it had in 2006.

1.8. Within the studied future periods, the Real Time wind generation forecasts (7.5 minutes before a five-minute dispatch interval) will not be incorporated into the CAISO MRTU Real Time Unit Commitment/Real Time Dispatch systems.

1.9. Wind generation forecasts are not biased over a season.

1.10. Wind generation schedules are solely based on the corresponding Hour Ahead wind generation forecasts that assumed to be available for the CAISO/IOU scheduling process.

1.11. Pump storage **is not** considered as a part of the actual load and the load forecast. It is considered as a scheduled resource. The impact of small pumps that are not scheduled and are included into the actual load is neglected.

2. CAISO Scheduling and Real Time Basics and Timelines

2.1 Generators' Schedules

Figure 1 illustrates how the generators in the CAISO control area are scheduled and dispatched.

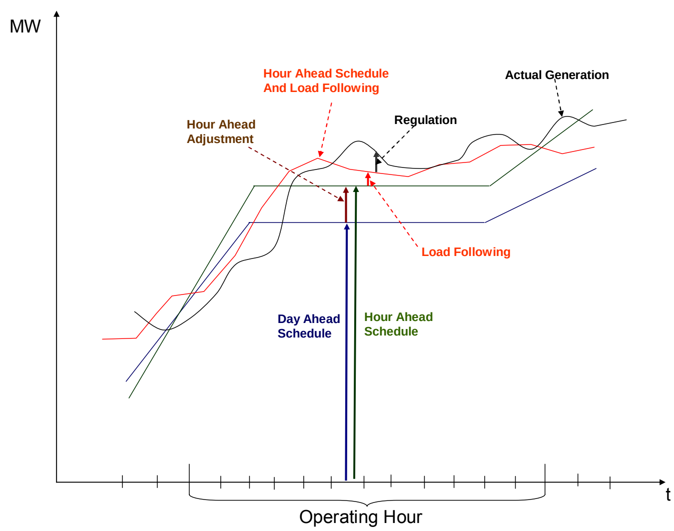

Figure 1: CAISO Control Area Scheduling Process

Hour Ahead schedules are block energy hourly schedules including the 20-minute ramps between the hours - Figure 2. They are provided 75 minutes before the actual beginning of an operating hour. The load forecast used for the Hour Ahead scheduling process is provided 2 hours before the beginning of an operating hour. The difference between the Day Ahead and Hour Ahead schedules constitute the required generation adjustment. CAISO facilitates the adjustment bids and the market.

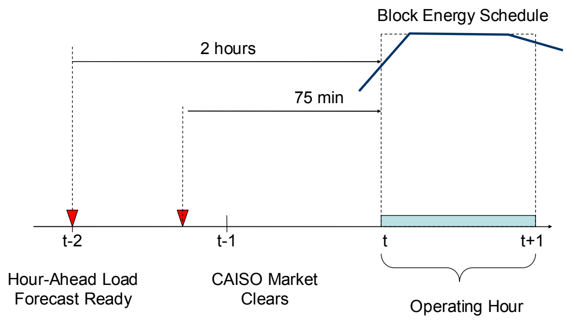

Figure 2: CAISO Hour Ahead Timeline

Load Following is an instructed deviation from schedule caused by the real time (or supplemental) energy dispatch. The desired changes of generation are determined in real time for each five-minute dispatch interval 7.5 minutes before the actual beginning of the interval. System information used for that purpose (including Real Time forecasts) is dated back approximately 7.5 minutes before the beginning of the interval.

2.2 Real Time Dispatch and Regulation

The Real Time Dispatch (aka Load Following or Supplemental Energy Dispatch) is automatically conducted by the CAISO's MRTU applications using 15-minute intervals for Real Time Unit Commitment and five-minute interval for Real Time Economic Dispatch. The timeline for this process is shown in Figure 3:[1].

[1] CAISO MRTU Training Document, Version 10.0.

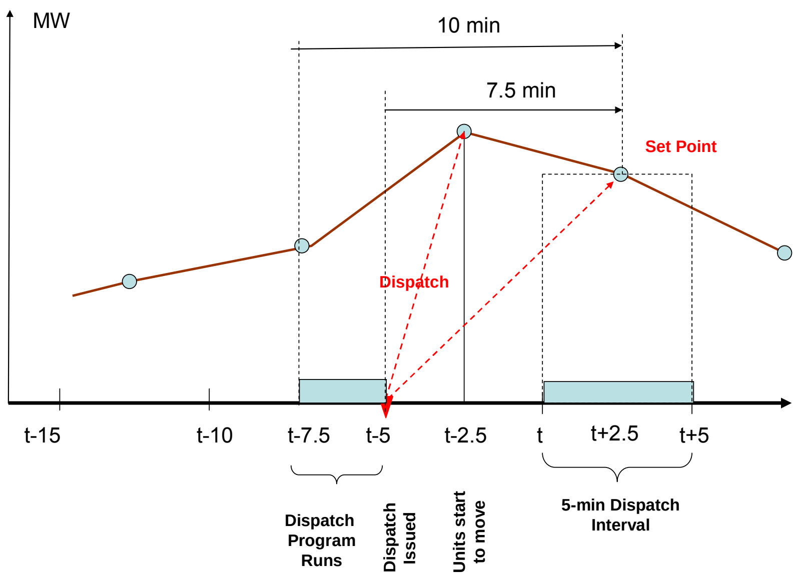

Figure 3: CAISO Real Time Dispatch Timeline

The desired changes of generation are determined in Real Time for each five-minute dispatch interval 5 minutes before the actual beginning of the interval. System information used for that purpose is dated back 7.5 minutes before the beginning of the interval. Units start to move toward the new set point 2.5 minutes before the interval begins. They are required to reach the set point in the middle of the interval (2.5 minutes after its beginning). The units may ramp by sequential segments, that is, the ramp is not necessarily constant.

The Very Short Term Load Predictor (VSTLP) program provides an average load forecast for the interval [t, t+5] 7.5 minutes before the beginning of the interval or 10 minutes before the middle point of this interval. The VSTLP program uses EMS data to generate the forecast. This program has also an option to use the Automated Demand Forecasting System (ALFS) output.

A similar timeline (forecast provided 7.5 minutes before the beginning of a five-minute interval) can be adopted for the future wind generation forecast.

2.3 Load Forecast Model

Refer to Appendix C for the methodology used to analyze Load Forecasting Errors

2.4 Wind Generation Forecast Model

The Hour Ahead wind generation forecast is assumed to be a part of the future CAISO/IOU scheduling system[2]. Without such forecast system, the CAISO load following requirements would become very significant in the year 2010. It is assumed that the wind generation forecast error is distributed according to the Truncated Normal Distribution (TND) law. Based on the assessment conducted by the AWS Truewind Company[3], the total 2-hours ahead wind energy forecast will have the following characteristics – see Table 1.

Table 1: Estimated Hour Ahead Wind Generation Forecast Characteristics

	average	**min**	**max**	**Standard Deviation**	**Autocorrelation**
Winter	0.00	-0.36	0.31	0.07	0.61
Spring	0.00	-0.43	0.31	0.09	0.71
Summer	0.00	-0.32	0.31	0.08	0.65
Fall	0.00	-0.32	0.40	0.08	0.59

3 Simulation of Future Scenarios and Data Set Generation

The study year is 2010 vs. the year 2006/2007.

3.1 Actual Load

For a future study year 2006+*i*, the annual actual load curve can be simulated as the year 2006 load multiplied by the *i*-th power of the annual load growth factor:

$$L_a^{2006+i} = (1+\gamma)^i \times L_a^{2006} \qquad (3.1)$$

The actual one-minute resolution load data is used for this study. The annual load growth factor is 1.5%.

3.2 Hour Ahead Load Schedule Model

The scheduled load is the one-hour (1*hr*) block energy schedule that includes 20 minute ramps between the hours. Please refer to Figure 4

---

[2] The assumption is that all new wind generation additions in California will participate in the PIRP program, and therefore they will be provided with a centralized day-ahead and Hour Ahead forecast service.

[3] The estimated data was provided by AWS Truewind and processed by Phillip de Mello.

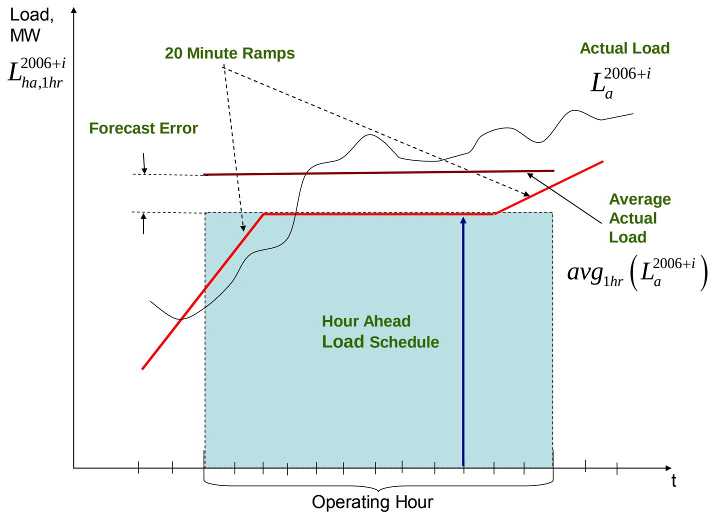

Figure 4: CAISO Simulated Hour Ahead Load Schedule (Red Line)

It can be calculated based on the load forecast error using the following approach.

The hour ahead (*ha*) load schedule $L_{ha,1hr}^{2006+i}$ can be simulated based on the projected actual load (3.1) and the expected load forecast error $\varepsilon_{L,ha}$:

$$L_{ha,1hr}^{2006+i} = \Re_{20}\left\{avg_{1hr} L_a^{2006+i} - \varepsilon_{L,ha}\right\} \tag{3.2}$$

Operator $\Re_{20}$ adds 20 minute ramps to the block energy load schedule.

The error can be simulated using a random number generator based on the statistical characteristics of the load forecast error (derived from the year 2006/2007 data.

The suggested probability distribution for the load forecast error is doubly truncated normal distribution shown in Figure 5:. The truncated distribution helps to eliminate “tails” of the normal distribution which would correspond to some unrealistically significant forecast errors.

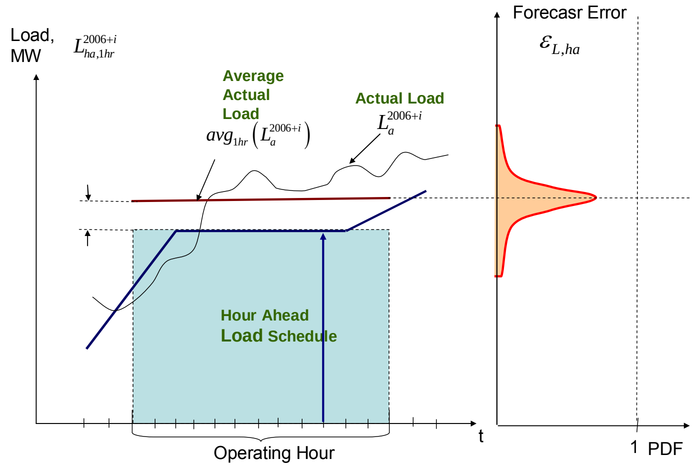

Figure 5: Probability Density Function (PDF) of the Load Forecast Function (Red Line)

Based on these specified values, a random number generator will be used to generate values of $\varepsilon_{L,ha}$. For each operating hour, the random values of $\varepsilon_{L,ha}$ will be substituted into (3.2) to produce the simulated Hour Ahead load schedule. It is assumed that the load error distribution is *unbiased* for $PDF_N(\varepsilon)$, that is $\varepsilon_0 = 0$, and $\varepsilon_{L,ha}^{\min}$, $\varepsilon_{L,ha}^{\max}$ correspond to the minimum and maximum forecast errors specified for this study. These values are set to the following values ($L_{ha,1hr}^{2006+i}$ is the year 2010 hour ahead scheduled load, and L_a^{2006+i} is the actual load at the same hour).

$$L_{ha,1hr}^{2006+i} = \Re\left\{avg_{1hr} L_a^{2006+i} - \varepsilon_{L,ha}\right\}, \varepsilon_{L,ha}^{\min} \le \varepsilon_{L,ha} \le \varepsilon_{L,ha}^{\max} \quad (3.3)$$

$$\varepsilon_{L,ha}^{\max} = 3\sigma_{L,ha}$$

$$\varepsilon_{L,ha}^{\min} = -3\sigma_{L,ha}$$

3.3 Real Time Load Forecast

The Real Time load forecast is the average five-minute load forecast that includes five-minute ramps between the dispatch intervals. Please refer to Figure 6:.

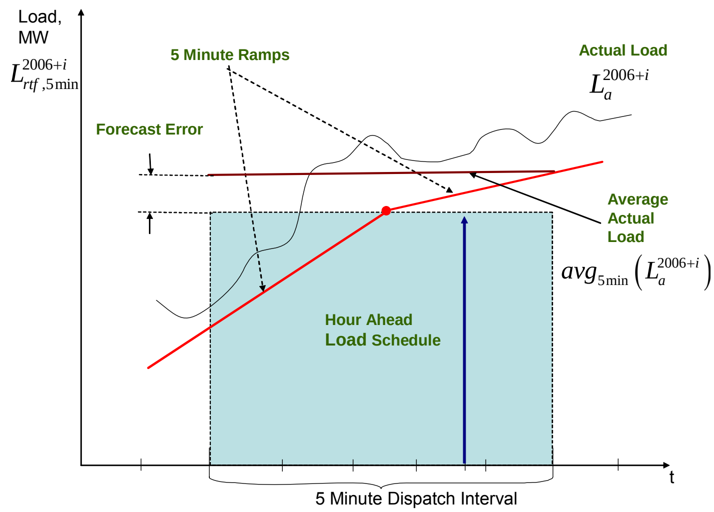

Figure 6: CAISO Simulated Real Time Load Forecast (Red Line)

It can be calculated based on the load forecast error using the following approach.

The real time load forecast $L_{rtf,5\min}^{2006+i}$ can be simulated based on the projected actual load (3.1) and the expected load forecast error $\varepsilon_{L,rtf}$:

$$L_{rtf,5\min}^{2006+i} = \Re_5\left\{avg_{5\min}L_a^{2006+i} - \varepsilon_{L,rtf}\right\} \tag{3.4}$$

Operator $\Re_5$ adds five-minute ramps to the block energy load schedule.

The error can be simulated using a random number generator based on the statistical characteristics of the real time load forecast error (derived from the year 2006/2007 data). The suggested probability distribution for the real time load forecast error is unbiased doubly truncated normal distribution. The values of $\varepsilon_{L,rtf}^{\min}$ and $\varepsilon_{L,rtf}^{\max}$ are set to plus/minus 3 $\sigma_{L,rtf}$. The standard deviation of the Hour Ahead load forecast error is $\sigma_{L,rtf}$.

Based on these specified values, a random number generator will be used to generate values of $\varepsilon_{L,rtf}$. For each operating hour, the random values of $\varepsilon_{L,rtf}$ will be substituted into (3.5) to produce the simulated real time load forecast.

$$\begin{aligned} &L_{rtf,5\min}^{2006+i} = \Re\left\{avg_{5\min}L_a^{2006+i} - \varepsilon_{L,rtf}\right\},\ \varepsilon_{L,rtf}^{\min} \le \varepsilon_{L,rtf} \le \varepsilon_{L,rtf}^{\max} \\ &\varepsilon_{L,rtf}^{\max} = 3\sigma_{L,rtf} \\ &\varepsilon_{L,rtf}^{\min} = -3\sigma_{L,rtf} \end{aligned} \tag{3.5}$$

3.4 Actual Wind Generation Model

Refer to Appendix D for the methodology used to scale wind generation for the 2010 timeframe.

3.5 Wind Generation Hour Ahead Scheduling Model

Wind generation Hour Ahead schedules can be simulated using the wind generation year 2010 model described in Appendix E and wind generation forecast error model described below. Similarly to the load Hour Ahead schedule and Real Time load forecast models, the wind generation schedules and forecasts can be simulated for the Hour Ahead scheduling and Real Time dispatch time horizons as follow:

- Wind generation schedule model $G^{w}_{ha,1hr}$ for the Real Time scheduling process (hourly block energy forecast schedule) is as follows:

$$G^{w,2006+i}_{ha,1hr} = \Re_{20}\left\{avg_{1hr}\left(G^{w,2006+i}_{a}\right) - \varepsilon_{w,ha} \cdot CAP^{w,2006+i}\right\} \tag{3.6}$$

  The wind generation forecast error is expressed in % of the WG capacity $CAP^{w,2006+i}$.

  Operator $\Re_{20}\{...\}$ adds 20-minute ramps between the hours; $\varepsilon_{w,ha}$ is the simulated Hour Ahead wind generation forecast error. This error is generated with the help of *unbiased* TND random number generator. The TND has the following characteristics:

    - Parameters $\varepsilon^{\min}_{w,ha}$, $\varepsilon^{\max}_{w,ha}$ correspond to the minimum and maximum total CAISO wind generation forecast errors specified for the TND. These values are set to plus/minus 3 standard deviation of the Hour Ahead wind generation forecast error $\sigma_{w,ha}$.
    - The standard deviation and autocorrelation of the Hour Ahead wind generation forecast error $\sigma_{w,ha}$ is set to the seasonal values provided in.

The truncation process is based on the following rules.

$$G_{ha,1hr}^{w,2006+i} = avg_{1hr} G_a^{w,2006+i} - \varepsilon_{w,ha} \cdot CAP^{w,2006+i}, \ \varepsilon_{w,ha}^{\min} \le \varepsilon_{w,ha} \le \varepsilon_{w,ha}^{\max}$$

$$\varepsilon_{w,ha}^{\max} = \begin{cases} 3\sigma_{w,ha}, \ if \ \left(avg_{1hr} G_a^{w,2006+i} - 3\sigma_{w,ha} \cdot CAP^{w,2006+i} \right) > 0, \\ avg_{1hr} G_a^{w,2006+i}, \ if \ \left(avg_{1hr} G_a^{w,2006+i} - 3\sigma_{w,ha} \cdot CAP^{w,2006+i} \right) \le 0. \end{cases} \tag{3.7}$$

$$\varepsilon_{w,ha}^{\min} = \begin{cases} -3\sigma_{w,ha}, \ if \ \left(avg_{1hr} G_a^{w,2006+i} + 3\sigma_{w,ha} \cdot CAP^{w,2006+i} \right) < CAP^{w,2006+i}, \\ avg_{1hr} G_a^{w,2006+i} - CAP^{w,2006+i}, \ if \ \left(avg_{1hr} G_a^{w,2006+i} + 3\sigma_{w,ha} \cdot CAP^{w,2006+i} \right) \ge CAP^{w,2006+i}. \end{cases}$$

Real Time wind generation forecast is not provided or included into the real time dispatch process. It is assumed that the naïve persistence model is implicitly used. Practically this means that for a five-minute dispatch interval [*t*, *t* + 5], the implicit real time wind generation forecast $G_{rtf,5\min}^{w,2006+i}$ is assumed to be equal to the actual wind generation at the moment *t* – 8:

$$G_{rtf,5\min}^{w,2006+i}[t, t+5] = G_a^w[t-8] \tag{3.8}$$

4 Assessment of Regulation and Load Following Impacts

NERC Operating Manual[4] considers regulation and load following requirements as parts of the Operating Reserve and gives the following definitions for these terms:

REGULATION. The provision of generation and load response capability, including capacity, energy, and maneuverability, that responds to automatic controls issued by the Balancing Authority". The regulation reliability objective is to "follow minute-to-minute differences between resources and demand".

LOAD FOLLOWING. The provision of generation and load response capability, including capacity, energy, and maneuverability, that is dispatched within a scheduling period by the Balancing Authority". The load following reliability objective is to "follow resource and demand imbalances occurring within a scheduling period".

4.1 Expressing Regulation and Load Following Requirements Using Simplified ACE Equation

The CAISO's control objective is to minimize its control area ACE to the extent sufficient to comply with the NERC Control Performance Standards. Therefore, the "ideal" regulation/load following signal is the signal that opposes deviations of ACE from zero when they exceed a certain threshold:

---

[4] "NERC Operating Manual", June 15, 2006.

$$
\begin{aligned}
-ACE &= -(I_a - I_s) + \underbrace{10B(F_a - F_s)}_{Neglected} \\
&\approx G_s - L_s - G_a + L_a \rightarrow \min
\end{aligned} \qquad (4.1)
$$

The generation component of the ACE equation can be represented as follows:

$$G_s = G_{ha} + G_{ha}^w,\ G_a = G_s + \Delta G^{lf} + \Delta G^r + \Delta G^w + \Delta G^{ud} \qquad (4.2)$$

where *ha* - denotes the hour ahead generation schedule; *lf* - denotes instructed deviations from the hour ahead schedule caused by generators involved into the load following process, *r* - denotes instructed deviations caused by generators involved into the regulation process, ΔG^{lf} and ΔG^r - is the deviation of the regulation and load following units from their base points, ΔG^w - is the deviation of the wind generators from their schedule (wind generation real time schedule forecast error), and ΔG^{ud} is the total deviation of generators from the dispatched instructions. ΔG^{ud} will be simulated similarly to the load forecast error (random number generator based on TND).

The total deviation of generators from dispatch instructions,

$$\Delta G^{ud} = G_a - G_{ha} \qquad (4.3)$$

for the conventional units that are not involved in regulation and load following.

We will also introduce the following notations:

$$
\begin{aligned}
&\Delta G^w = G_a^w - G_{ha}^w, \\
&\Delta L = L_a - L_{ha}
\end{aligned} \qquad (4.4)
$$

Since the control objective is $ACE \rightarrow 0$, we can rewrite (4.1) as

$$\Delta G^{lf} + \Delta G^r = \Delta L - \Delta G^w - \Delta G^{ud} \qquad (4.5)$$

where ΔL - is the deviation of the actual load from its real time scheduled value (= load forecast error).

NOTE (1): Equation (4.5) is written for instantaneous values of ΔL, ΔG^w, and ΔG^{ud} Therefore, the statistical interaction between the load forecast error and the wind generation forecast error is fully preserved in (4.5).

NOTE (2): The load and wind generation errors can vary depending on the wind generation penetration level in the CAISO system and the accuracy of the load forecast compared to the accuracy of the wind generation forecast. Since the percent wind generation forecast error is more significant than the percent load forecast error, the former may have a considerable impact on $\Delta G^{lf} + \Delta G^r$.

4.2 "Would Be" Regulation Requirement without Wind Generation

Wind generation would have no impact on regulation and load following requirements if

$$\Delta G^{w} = 0 \tag{4.6}$$

By substituting (4.6) into (4.5),

$$\Delta G^{rlf} = \Delta G^{lf} + \Delta G^{r} = \Delta L - \Delta G^{ud} \tag{4.7}$$

4.3 Regulation and Load Following Assessment

This procedure can be used to separate regulation from load following based on short-term forecasts of the system total load and total wind generation.

The schedule/forecast based approach uses the short-term forecasts of wind generation and load, $G^{w,y}_{rtf,5\min}$ and $L^{y}_{rtf,5\min}$. In this case, the following formulas can be used:

$$\begin{aligned}
\Delta G^{r}(m) &= L^{y}_{a}(m) - G^{w,y}_{a}(m) - L^{y}_{rtf,5\min}(m) + G^{w,y}_{rtf,5\min}(m), \\
\Delta G^{lf}(m) &= L^{y}_{rtf,5\min}(m) - G^{w,y}_{rtf,5\min}(m) - L^{y}_{ha,1hr}(m) + G^{w,y}_{ha,1hr}(m)
\end{aligned} \tag{4.8}$$

Figure 7 illustrates the idea of separation of regulation from load following based on short-term forecasts.

Load Following is understood as the difference between the hourly energy schedule including 20-minute ramps[5] (shown as the red line) and the short-term five-minute forecast/schedule and applied "limited ramping capability" function (blue line). This difference is also shown as the green area below the curves.

Regulation is interpreted as the difference between the actual CAISO generation requirement and the short-term five-minute forecast/schedule and applied "limited ramping capability" function (green and blue lines correspondingly). In Figure 7, it is also shown separately as the tan area.

[5] IMPORTANT NOTE: The actual CAISO real time dispatch process is based on the actual generation, but not the real time schedules (Source: Tong Wu, June 7, 2007). The scheduled generation used in the proposed procedure based on the Assumptions, Section 1.

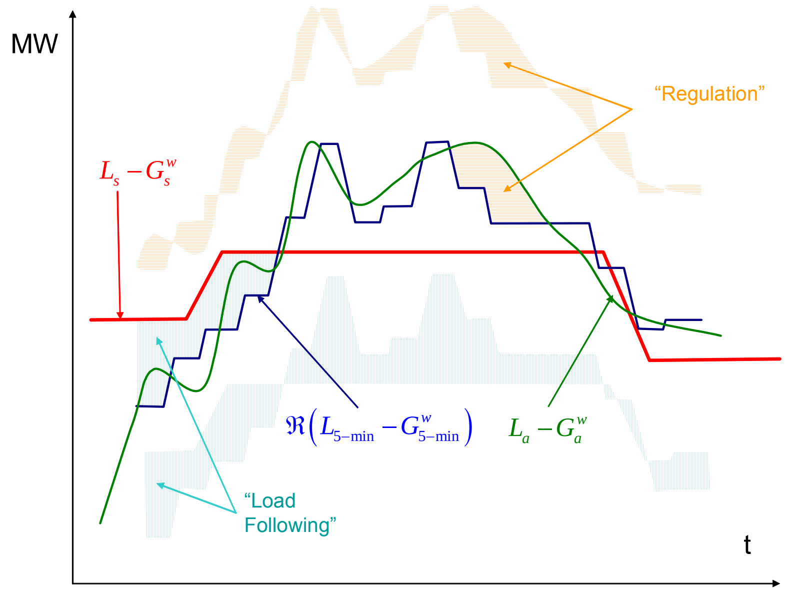

Figure 7: Separation of Regulation from Load Following Based on Simulated Hour Ahead Schedule

5 Assessment of Ramping Requirements

The regulating unit ramping capability can directly influence the required regulation and load following capacity. If the ramping capability is insufficient, more units and more capacity must be involved in regulation to follow the ramps. That is why the additional ramping requirements caused by wind generation should be studied and quantified.

The required ramping capability can be derived from the shape of the regulation/load following curve ΔG^{rlf} . This derivation needs to be done in a scientific way. We propose to use the "swinging door"[6] algorithm for this purpose. This is a proven technical solution implemented in the PI Historian and widely used to compress and store time dependent datasets.

Figure 8 demonstrate the idea of the "swinging door" approach. A point is classified as a "turning point" whenever for the next point in the sequence any intermediate point falls out of the admissible accuracy range $\pm\varepsilon_{\Delta G}$. For instance, for point 3, one can see that point 2 stays inside the window *abcd*. For point 4, both points 2 and 3 stay within the window *abef*. But for point 5, point 4 goes beyond the window, and therefore point 4 is marked as a turning point.

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[6] D.C. Barr, "The Use of a Data Historian to Extend Plant Life", Life management of power plants, 12-14 December 1994, Conference Publication No. 401.0 IEE 1994.

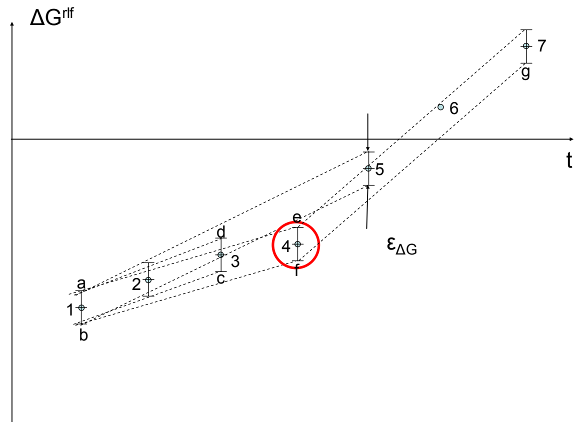


Figure 8: "Swinging Door" Algorithm - Idea

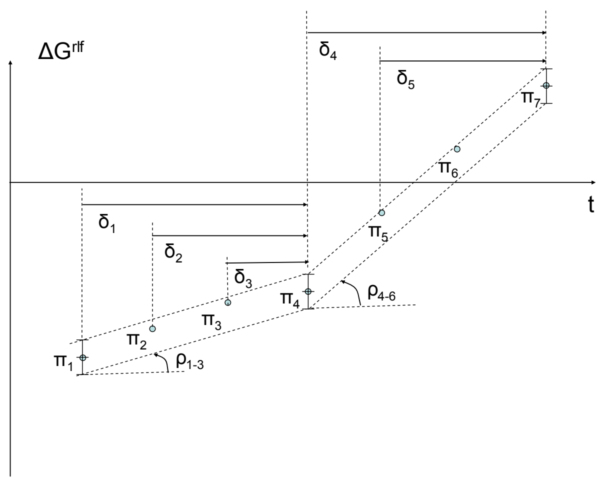


Figure 9: "Swinging Window" Algorithm – Obtaining Regulation, Ramps, and Their Duration

Based on this analysis, we conclude that points 1,2, and 3 correspond to the different magnitudes of the regulation signal, π_1, π_2 and π_3, whereas the ramping requirement at all these points is the same, ρ_{1-3}. The swinging door algorithm also helps to determine the ramp duration δ.

6 Concurrent Statistical Analysis of the Regulation and Load Following Requirements

As it has been discussed before, the regulation capacity and ramping requirements are inherently related. Insufficient ramping capability could cause additional capacity requirements.

In this document, we propose a concurrent consideration of the regulation and load following capacity, ramping and ramp duration requirements.

For the regulation/load following requirement curve ΔG^{rlf} , we can apply the "swinging door" algorithm and determine the sequences of its magnitudes and ramps, $\pi_1, \pi_2, \ldots$, $\rho_1, \rho_2, \ldots$, and $\delta_1, \delta_2, \ldots$. The triads $(\pi_i, \rho_i, \delta_i)$ can be used to populate the three-dimensional space of these parameters – see Figure 10:.

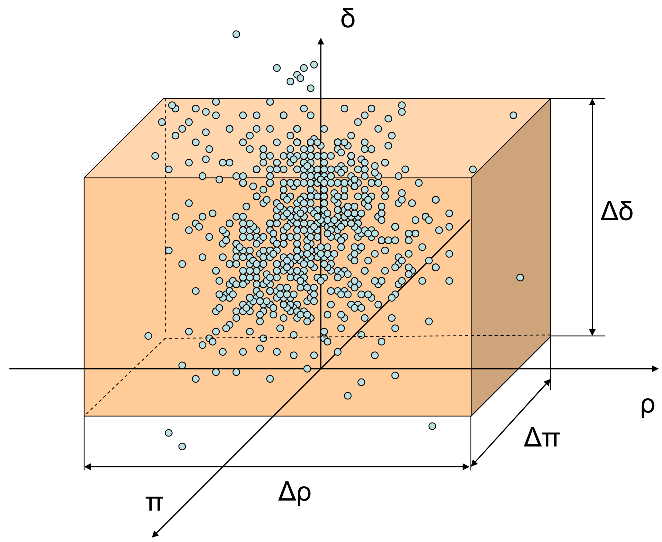


Figure 10: Concurrent consideration of the capacity, ramping and duration requirements

For given ranges of these three parameters, $\Delta\pi, \Delta\rho$ and $\Delta\delta$, a box can be plotted in this space, so that some triads are inside the box (N_{in}), some are outside (N_{out}). This approach helps to determine the probability of being outside the box,

$$p_{out} = \frac{N_{out}}{N_{out} + N_{in}}$$

If a point lays outside the box, the regulation/load following requirements are not met at this point. We will require that this probability must be below certain minimum probability, $P_{\min}$. The task is to find the position of the wall of the probability box that corresponds to a given $P_{\min}$.

Appendix C --- Load Forecast Error Analysis

Load Forecast

The CAISO Forecasted Demand is calculated by the Automated Demand Forecasting System (ALFS). ALFS calculates the CAISO Forecasted Demand for several different timeframes. The Day-Ahead forecast is calculated approximately 14 hours before the operating day, while the Hour Ahead forecast is calculated about two hours prior to the operating hour and subsequent half-hour forecast are calculated for the remainder of the operating day. This process is repeated before each operating hour and each subsequent Half-Hour forecast is modified. Each of the Half-Hour forecast for the remainder of the operating day is used by the Security Constrained Unit Commitment program so that short start units could be committed if it's anticipated that resources would be deficient.

In the CAISO's Real Time Market Systems, another forecasting tool called the Very Short Term Load Predictor (VSTLP) utilizes the latest ALFS Half-Hour forecast and the most recent generation output from the State Estimator to forecast a 15-minute Demand Forecast, which is used by Real Time Unit Commitment (RTUC) and a five-minute forecast which is used by Real Time Economic Dispatch. Under MRTU, all Forecasted Demand would include transmission losses but would exclude pump loads.

Load Forecasting Error

In order to assess the expected forecasting error for the 2010 timeframe, it was decided to ascertain the actual forecasting errors observed in 2006. For this study, the seasonal forecasting errors for 2006 are assumed to be the same for 2010 although some may argue that forecasting errors would be higher at higher load levels. The reason for assuming the forecasting errors would be about the same as it is now is the expectation that forecasting errors would be reduced with improved forecasting techniques and additional weather information.

The Forecasted Demand errors were characterized for three timeframes, the Hour Ahead, Half Hour, and five-minute forecasts. For each timeframe, the forecasted error was determined by taking the difference between the forecasted demand for that timeframe and the actual average demand for the corresponding period. The maximum, minimum, average, and standard deviation were calculated on the error for each timeframe. The probabilities of error magnitudes were then calculated by comparing the number of occurrences in error magnitude ranges to the total number of occurrences. The probability density function can be approximated using a truncated normal distribution that is defined by using the mean and standard deviation for the forecast error for the different seasons. Refer to Figure 1.

The truncated normal distribution is very similar to a normal distribution but differs in that its extremities are bounded or truncated. The truncated normal distribution is more practical for load forecasting data because it is not expected that the forecasting error would exceed certain limits. The formula for the truncated normal distribution used in this study is given below:

$$PDF_{TND}(\varepsilon) = \begin{cases} 0, & -\infty \le \varepsilon < \varepsilon_{\min} \\ \dfrac{PDF_N(\varepsilon)}{\int_{\varepsilon_{\min}}^{\varepsilon_{\max}} PDF_N(\varepsilon)d\varepsilon}, & \varepsilon_{\min} \le \varepsilon \le \varepsilon_{\max} \\ 0, & \varepsilon_{\max} \le \varepsilon \le +\infty \end{cases}$$

$$PDF_N(\varepsilon) = \frac{1}{\sqrt{2\pi\sigma^2}} e^{-\frac{1}{2}\left(\frac{\varepsilon-\varepsilon_0}{\sigma}\right)^2}, \ -\infty \le \varepsilon \le +\infty$$

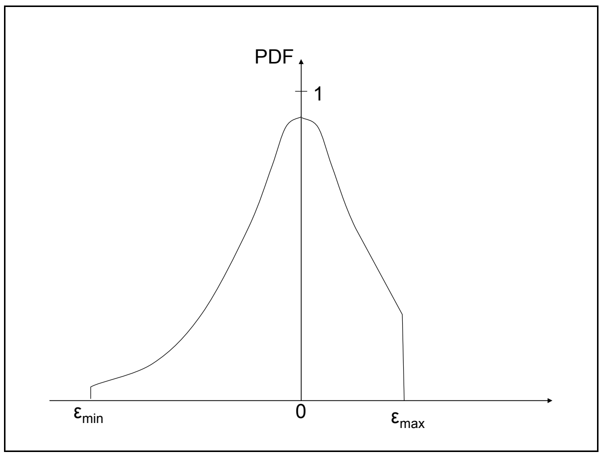


Figure 1: Unbiased Truncated Normal Distribution

Additionally, the autocorrelation coefficient (*R*) was calculated to see if the forecasted errors are time dependent, (i.e. is the forecasted load typically under-forecasted or over-forecasted for certain time periods?) The autocorrelation depends on the number of observations, the standard deviation of the observations, the sample mean and the current and next observation. Autocorrelation has values between -1 and 1. A value of 1 indicates that the next value has a very strong positive dependence on the previous value, while a value of -1 indicates that the next value has a strong negative dependence on the previous value. An autocorrelation value of zero indicates that the current value gives no indication of what the next value will be.

$$R = \frac{1}{(n-1)\sigma^2} \sum_{i=1}^{n-1} (X_i - \mu)(X_{i+1} - \mu)$$

Where: *n* is the number of occurrences
X is the value of the error at that time
μ is the average value of the error
σ is the standard deviation of the error

Hour Ahead Forecast

Currently and prior to MRTU implementation, the Hour Ahead Forecast error is simply the difference between the Hour Ahead forecast and the average hourly actual demand (including pump loads) for a particular operating hour. For 2006, the Hour Ahead forecast was found to have a mean absolute error (MAE) of 2% of actual load.

$$MAE = \frac{1}{N} \sum \frac{|Actual - Forecast|}{Actual} \times 100$$

The raw forecasting error data was filtered through a two-step process to remove bad data points: (1) errors in excess of 50% of actual load were removed, and (2) errors greater than 3 standard deviations from the mean were removed if there were data errors or problems on the grid.

Table 1 summarizes the minimum, maximum, average, standard deviation and autocorrelation of the Hour Ahead load forecasting Errors for the different seasons.

Table 1: Summary of Hour Ahead load forecast error (Actual Load – Forecast Load)

Season	Average (MW)	Min (MW)	Max (MW)	Standard Deviation (MW)	Autocorrelation
Winter	-35.2	-3,849	1,519	652	0.69
Spring	-24.1	-2,101	1,931	601	0.73
Summer	-130.4	-3,771	2,446	900	0.89
Fall	-69.2	-2,628	2,081	687	0.83

Figure 2a, b, c & d shows the seasonal comparisons of the theoretical load error distribution (red line) to actual load error distributions (blue bars). During the spring, fall and winter months the forecasting errors typically mimics a truncated normal distribution function. As shown in Figure 2b, during the 2006 summer months, the load forecasting error was typically on the high side or was greater than 800 MW for approximately 23 percent of the time. Much of this high forecast was due to the number of days the average temperature exceeded 100 degrees within the control area.

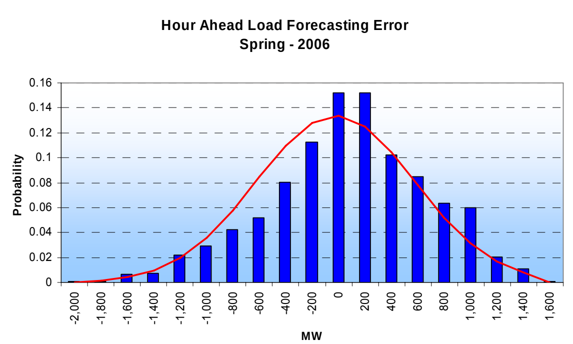


Figure 2a: Spring Load Forecasting Error

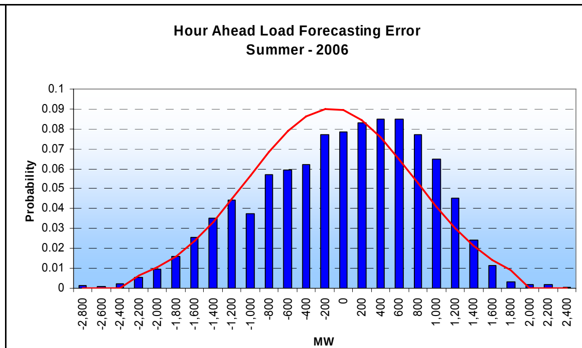


Figure 2b: Summer Load Forecasting Error

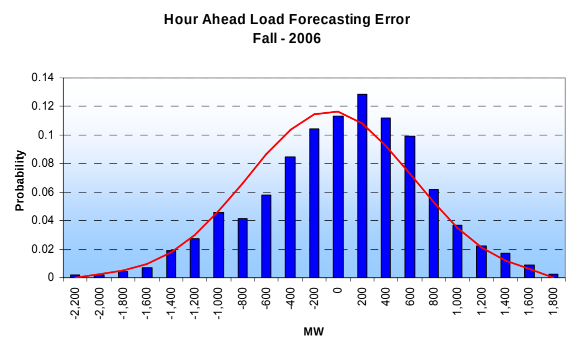


Figure 2c: Fall Load Forecasting Error

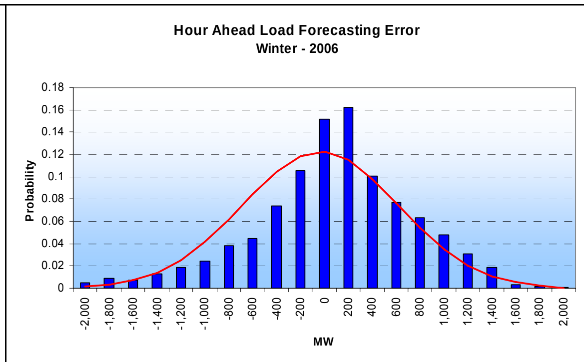


Figure 2d: Winter Load Forecasting Error

Half-Hour Forecast

The Half-Hour forecasts are similar to the Hour Ahead forecasts except they provide a more granular view of the operating hour in question. Once again the load data was extracted from the PI database, with the difference that it is Half-Hour averages rather than hourly averages. The time period used was January through June of 2007. Half-Hour forecast errors were not evaluated by season because of missing data. Additionally, the Half-Hour Load forecast does not include pumping load, so pump loads were removed from the actual Half-Hour load data for the comparison. The mean absolute error for the Half-Hour forecast was found to be 0.77%. Table 2 below shows the minimum, maximum, average, standard deviation and autocorrelation of the Half-Hour forecasting error.

Table 2: Summary of Half-Hour Load Forecasting Error

Average (MW)	**Min (MW)**	**Max (MW)**	**Standard Deviation (MW)**	**Autocorrelation**
-8.90	-1370	1520	258	0.89

As shown in Figure 3, the Half Hour load forecasting error is significantly smaller than the Hour Ahead forecasting error. For the first half of 2007, the forecasting error was greater than 500 MW approximately 5% of the time.

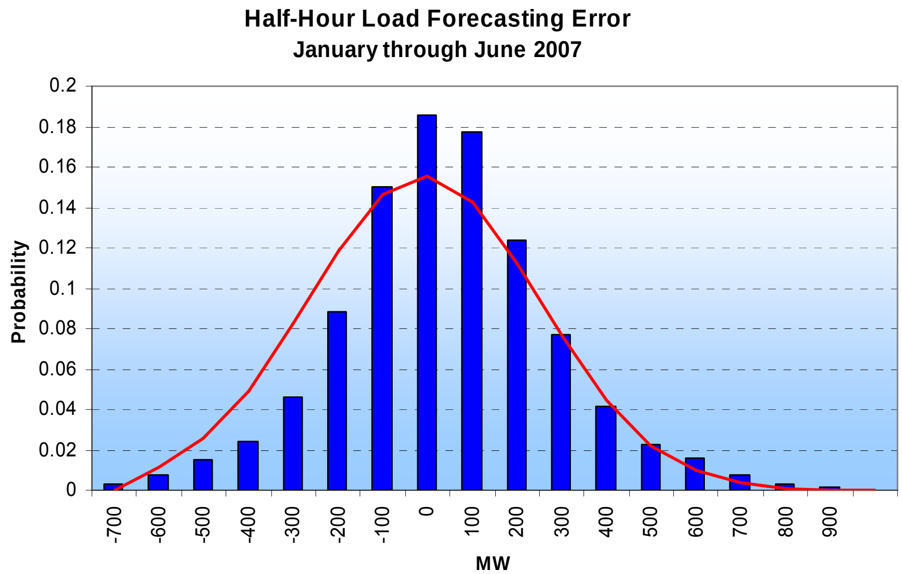


Figure 3: Comparison of Half-Hour Load Forecast Error with Theoretical Distribution

Five-Minute Forecast (Real Time Forecast)

The five-minute load forecast is calculated by the CAISO's VSTLP application, which is based on neural network training. It uses five-minute averages of actual load data (including pump load) generated from the State Estimator for the last 13 months as input. The VSTLP produces a Load forecast for each five-minute Dispatch Interval in the Real Time Market Time Horizon. This five-minute forecast is run about 10-minutes before the operating interval and consists of a block of power for that time. Variation within that five-minute interval is made up with regulation. The five-minute load data and the five-minute load forecasts were extracted from the SI UP database. The Mean Absolute Error of the five-minute load forecast is 0.29%. Table 3 below shows the minimum, maximum, average, standard deviation and autocorrelation of the five-minute forecasting error.

Table 3: Summary of five-minute Load Forecast Error

Average (MW)	Min (MW)	Max (MW)	Standard Deviation (MW)	Autocorrelation
1.15	-349	349	98	0.61

Figure 4 shows the five-minute load forecasting error for one month of data (mid-March through mid-April) is less than 100 MW for almost 85% of the time.

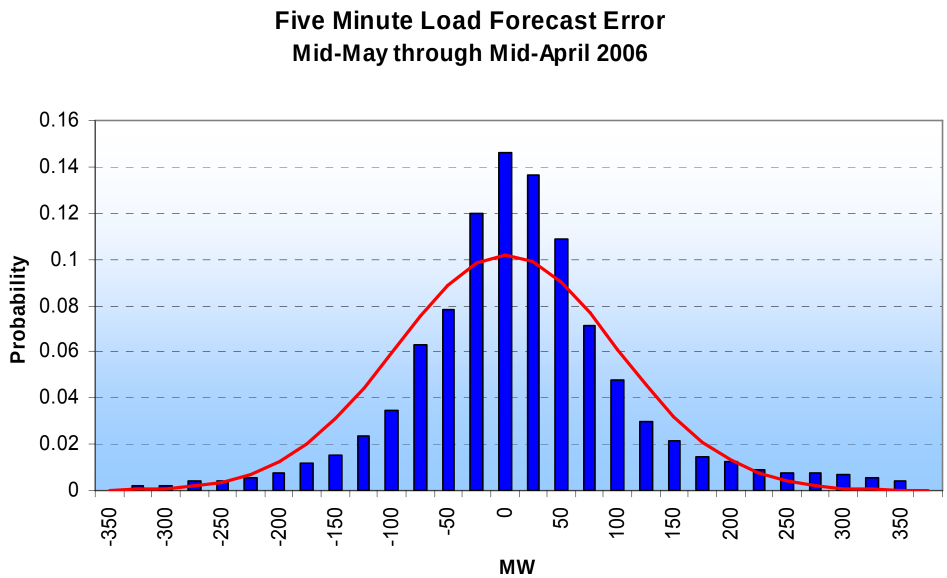


Figure 4: Comparison of five-minute Load Forecast Error and Theoretical Error Distribution

Appendix D --- Wind Generation Forecasting for 2010

Scaling Wind for 2010

Creating a realistic wind forecast dataset is one of the most important steps in analyzing the wind variability in the 2010 timeframe. Simply scaling the 2006 actual wind production by the ratio of the expected 2010 capacity to the current capacity fails to take into account any local weather variation within a resource area. This methodology would also neglect any benefits of aggregation which will reduce overall variability. The following approach describes the methodology used to create a reasonable dataset of future wind generation based on the realized 2006 wind production, which remedies some of the problems with direct scaling.

The 2010 energy production and minute-to-minute variability were calculated separately. The reason for calculating the expected 2010 production separately stems from the fact that wind energy production and variability during short time intervals are often driven by separate phenomenon. For the analysis and based on the CAISO's generation interconnection queue, three new wind parks totaling 3,540 MW were assumed to be located in the Tehachapi area and a new 500 MW wind park located in the Solano area. The other existing wind parks were assumed to remain the same as 2006.

Energy production

The 2010 hourly energy production data for the Tehachapi and Solano regions were provided by AWS Truewind. The data is the same as that used in the CEC IAP study, except that it omits facilities that are not likely to be constructed by 2010. AWS Truewind generated the 2010 wind production data using actual production data from January 2002 through December 2004 combined with their atmospheric simulation models to create wind speeds for the resource areas. AWS Truewind then extracted production values based on the resource area conditions with local corrections for each site and the expected power curve.[7] The AWS Truewind initial dataset is comprised of hourly block energy forecast for each of the existing and expected wind parks in the Tehachapi and Solano areas as shown in Figure 1. As shown in Figure 2, 20-minute linear inter-hour ramps were added to this original dataset to smooth the overall shape, and to prevent changes between hours from introducing artificial variation. Figure 1 shows sample energy production data with the inter hour ramps added.

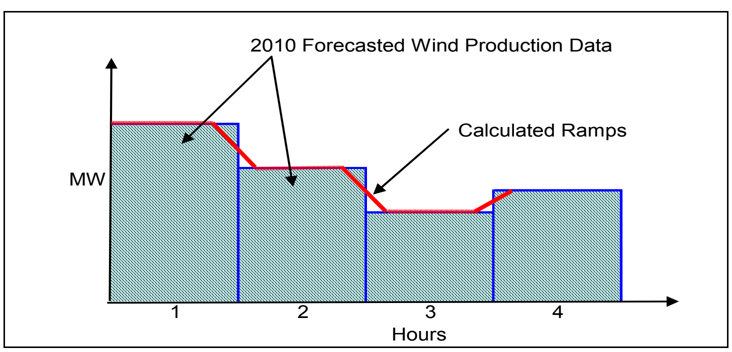


Figure 1: 2010 Wind Energy Production With Linear Ramps

Minute-to-minute Variability

The minute-to-minute variability is the actual minute-to-minute variation observed from the existing wind production in the various resource areas for 2006. The minute-to-minute variations are defined as the 1-minute deviation from a 60-minute centered moving average. Using a centered moving average takes out the longer term trends in the wind production (i.e. ramping up in the evening or down in the morning). A 60-minute average was used to closely match the energy given as hourly blocks. **Error! Reference source not found.** shows a sample of wind production and a comparison between the hourly average and the moving average. Since the 2010 energy production values are not based on the 2006 wind production data, it can at times have opposite inter hour trends. These opposite trends could exacerbate the variability if it were taken from fixed hourly averages of 2006 data and then combined directly onto the 2010 production. **Error! Reference source not found.** shows how the inter-hour trends in energy can be different between the two datasets.

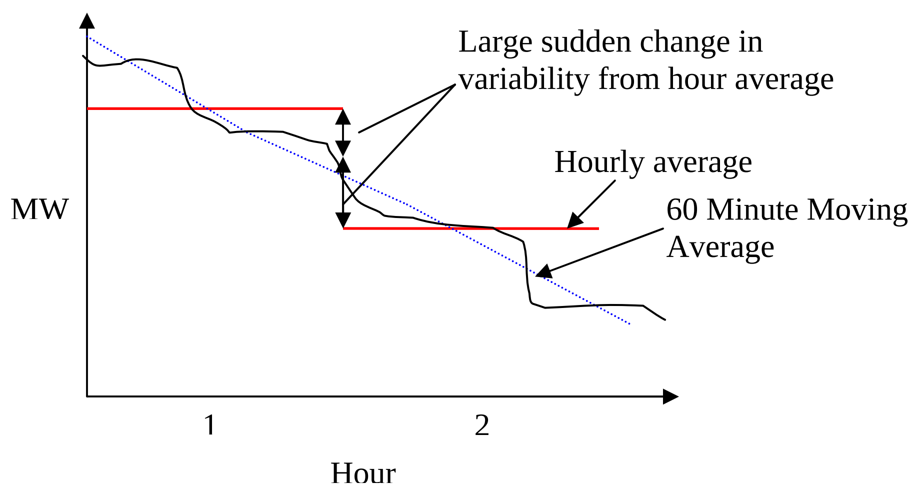
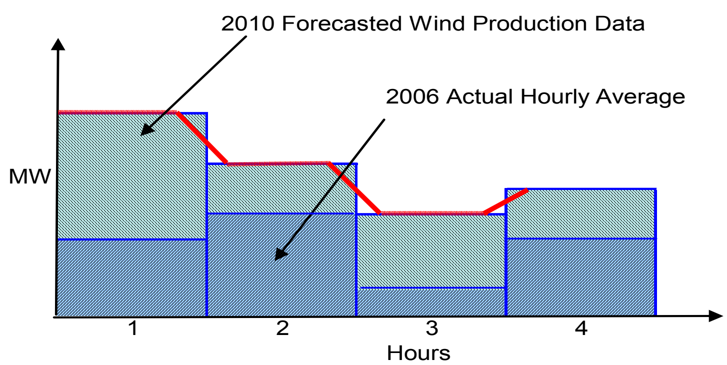


Figure 2: Sample Wind production with hourly average, and moving average



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[7] "Intermittency Analysis Project: Characterizing New Wind Resources in California" PIER Interim Project Report. California Energy Commission. CEC-500-2007-014. February 2007.

Figure 3: Possible Average wind generation pattern

The variability was then scaled up assuming that new wind farms would have similar levels of variability and that short term variations would be completely uncorrelated.

Figure 4 shows the correlation coefficient of short term fluctuations of two wind parks in Tehachapi, shows there is no significant correlation. The correlation coefficient is a measure of the extent that two variables are changing together. It is bounded between one and negative one. If it has a value of one the two variables always change together in the same direction, they change in opposite directions if it is negative one. If the correlation coefficient is zero, the two variables vary completely independent of each other. The equation for the correlation coefficient is shown below.

$$Correlation = \frac{\sum_{1}^{N}(X-\mu_X)(Y-\mu_Y)}{(N-1)\sigma_X\sigma_Y}$$

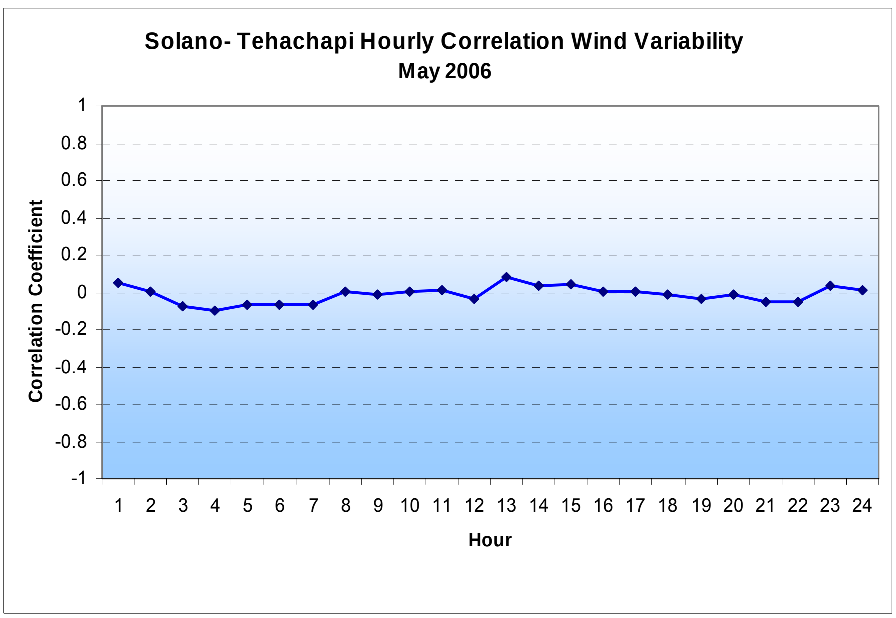

Figure 4: Correlation of short-term variations of two wind parks in Tehachapi resource area

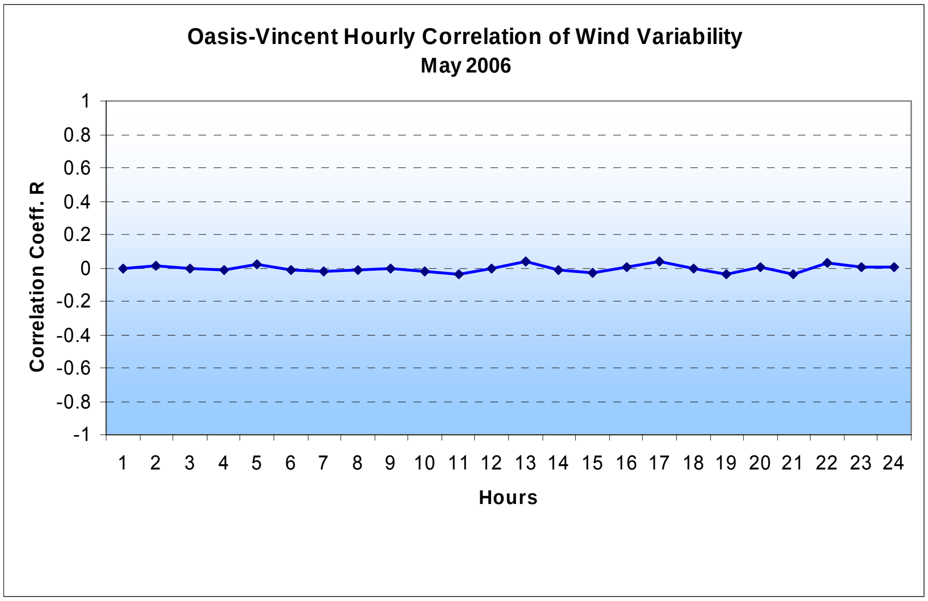

Figure 5: Correlation of short-term variations of two wind parks in Tehachapi resource area

Since the variability of the parks is independent, the standard deviations are added together as the square root of the sum of the squares. The scale factor (γ) is then determined by calculating the expected standard deviation and dividing that by the current standard deviation:

$$\gamma = \frac{\sqrt{\frac{MW_{2010}}{MW_{2006}}\sigma^2}}{\sigma} = \sqrt{\frac{MW_{2010}}{MW_{2006}}}$$

The minute-to-minute variation is then multiplied by this scaling factor for each minute to get the expected variability for 2010. The variability from the Oasis wind park and the wind parks connected to the Vincent substation were analyzed separately. These two wind parks were used in the analysis because Real Time telemetry from these sites are updated and send to the CAISO every four seconds. The Oasis wind park (60 MW) is made up of newer wind turbines, and it is assumed that future additions will behave similarly to the turbines installed at Oasis. Thus, the scaling was split so that the Oasis minute-to-minute variability was scaled such that it represents 75% of the expected Tehachapi addition. The Vincent substation variability was scaled to represent the remaining 25%. The scaled variability's were added together minute by minute to give the total Tehachapi distribution. A similar method was used in the Solano area. For the Solano area, the two parks used were the Shiloh wind park and the High Winds wind park. Since both of these parks are relatively new an equal weight (50%) was placed on the variability of each. Finally, the energy component and the 1-minute variability were added together to give the one-minute wind production values.

Appendix E --- Wind Forecasting Error

Characterizing Wind Generation Forecast Error

The two-hour ahead wind forecast error was analyzed in order to give an estimate of the types of errors one could expect in the 2010 time frame. The wind forecast error is defined as a percentage of total installed wind park capacity and is calculated by taking the difference between the actual and forecast production for a given hour divided by the plants capacity. The dataset used was provided by AWS Truewind, which provided the forecast error for June 2006 through May 2007. The statistics for the forecast error were also calculated for each time frame and are summarized in Table 1. In addition to the seasonal statistics the mean absolute percent error (MAPE) was also calculated to be 5.94% for the entire time period.

$$\varepsilon = \frac{Actual - Forecast}{Capacity}$$

$$MAPE = \frac{1}{N}\sum_{i=1}^{i=N}\left|\varepsilon_i\right|$$

Additionally, the autocorrelation error (*R*) was calculated to see if the forecasted errors are time dependent, (i.e. is the forecasted wind generation typically under-forecasted or over-forecasted for certain time periods?) The autocorrelation depends on the number of observations, the standard deviation of the observations, the sample mean and the current and next observation. Autocorrelation has values between -1 and 1. A value of 1 indicates that the next value has a very strong positive dependence on the previous value, while a value of -1 indicates that the next value has a strong negative dependence on the previous value. An autocorrelation value of zero indicates that the current value gives no indication of what the next value will be.

$$R = \frac{1}{(n-1)\sigma^2}\sum_{i=1}^{n-1}(X_i - \mu)(X_{i+1} - \mu)$$

Where: *n* is the number of occurrences
X is the value of the error at that time
μ is the average value of the error
σ is the standard deviation of the error

Table 1: Summary of Wind Forecast Error

	Average	Minimum	Maximum	Standard Deviation	Autocorrelation
Winter	0.00	-0.36	0.31	0.07	0.61
Spring	0.00	-0.43	0.31	0.09	0.71
Summer	0.00	-0.32	0.31	0.08	0.65
Fall	0.00	-0.32	0.40	0.08	0.59

Finally, the statistical distribution of the forecast error was analyzed. It was compared to a truncated normal distribution. The truncated normal distribution is very similar to a normal distribution but differs in that its extremities are bounded or truncated. The truncated normal distribution is more practical for real datasets which cannot have infinite values. For example we would not expect the wind forecast error to exceed the plant capacity. It is a piecewise function, which ensures that there is no chance of a value occurring outside the bounds, which is rescaled by the normal distribution to give an area under the curve of 1. The formula for the truncated normal distribution is given below.

$$PDF_{TND}(\varepsilon) = \begin{cases} 0, & -\infty \le \varepsilon < \varepsilon_{\min} \\ \dfrac{PDF_N(\varepsilon)}{\int_{\varepsilon_{\min}}^{\varepsilon_{\max}} PDF_N(\varepsilon)\, d\varepsilon}, & \varepsilon_{\min} \le \varepsilon \le \varepsilon_{\max} \\ 0, & \varepsilon_{\max} \le \varepsilon \le +\infty \end{cases}$$

$$PDF_N(\varepsilon) = \frac{1}{\sqrt{2\pi\sigma^2}} e^{-\frac{1}{2}\left(\frac{\varepsilon-\varepsilon_0}{\sigma}\right)^2}, \quad -\infty \le \varepsilon \le +\infty$$

The truncated normal distribution is a good fit for the data as shown in the following Figures 1a, b, c & d.

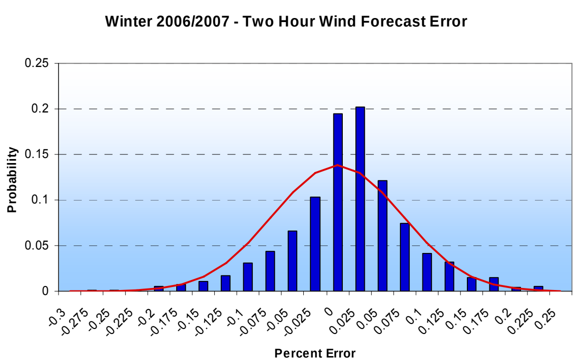

Figure 1a: Winter Forecasting Error

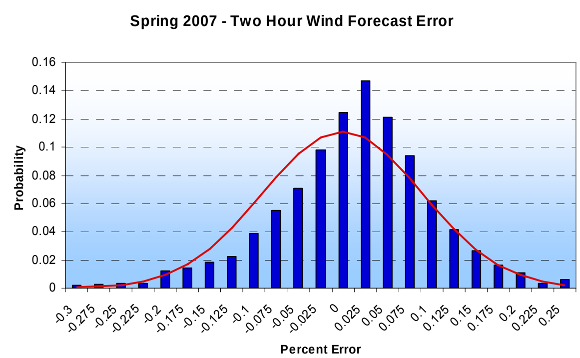

Figure 1b: Spring Forecasting Error

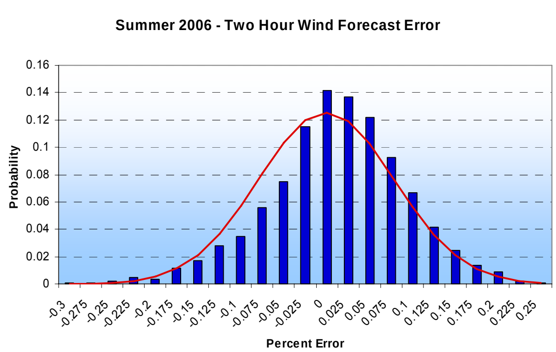

Figure 1c: Summer Forecasting Error

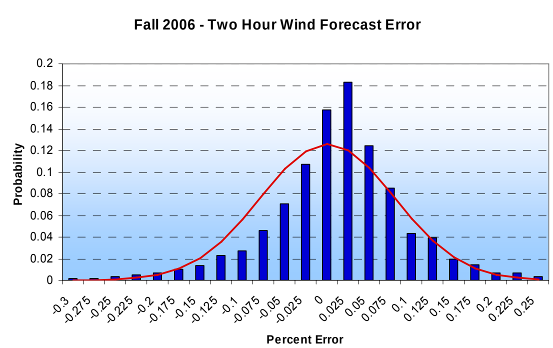

Figure 1d: Fall Forecasting Error

Appendix F

WIND TURBINE GENERATOR MODELING

1. Power Flow Model

The modeling of a wind plant for load flow analysis is simple. Wind plants normally consist of a large number of individual WTGs. The wind plant model may consist of a detailed representation of each WTG and the collector system. Alternatively, the simpler model shown in Figure 1 is adequate for most bulk transmission system studies. This model consists of a single WTG and unit transformer with MVA ratings equal to **N** times the individual device ratings, where **N** is the number of WTGs in the wind plant (or those considered to be on-line for study purposes). An equivalent impedance to reflect the aggregate impact of the collector system can be included together with the substation step-up transformer(s). The total charging capacitance of the collector system can also be included. The charging capacitance can be significant since underground cables are often used for the collector system. A third alternative is to model several groups of WTGs, each represented by a single model, with a simplified representation of the collector system. The wind plants included in this study use both of these equivalent modeling approaches.

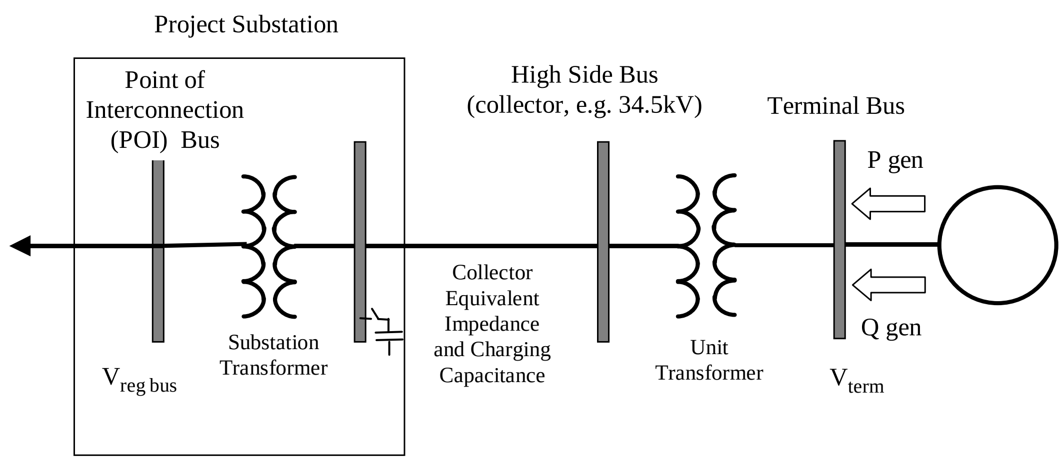

Figure 1: Wind Plant Equivalent Model.

From an analysis perspective, it is important to understand that the aggregate WTG behaves like a conventional generator connected to a (PV) bus in the powerflow analysis. The generator Pgen, Qmax, and Qmin are input to reflect the aggregate WTG capability. Typical collector system voltages are at distribution levels (12.5kV or 34.5kV are common). The substation transformer is suitably rated for the number of WTGs. Some of the wind plant models in this study include shunt capacitors on the collector side of the substation transformer, as illustrated in Figure 1. These capacitors replace or augment reactive capability from the WTGs, so that the power factor requirement of the grid code is met.

2. Dynamic Model

2.1 WECC Standard Models

Dynamic modeling of wind generation, particularly newer technology WTGs, is a challenge for the industry. The Western Electricity Coordinating Council (WECC) Modeling & Validation Work Group (MVWG) convened a Wind Generator Modeling Group (WGMG) in 2005 to address the challenge. The charter of that group is to "develop a small set of generic (non-vendor specific), non-proprietary, positive-sequence power flow and dynamic models suitable for representation of all commercial, utility-scale WTG technologies in large scale simulations." The models are suitable for typical transmission planning and system impact studies. All of the current commercially available utility scale wind turbines can be grouped into four basic topologies based on how they interface with the grid. The notation that the WG adopted, and which is gaining industry acceptance, is:

Type 1 – conventional induction generator

Type 2 – wound rotor induction generator with variable rotor resistance

Type 3 – doubly-fed induction generator

Type 4 – full converter interface

Simple schematics of these four topologies are shown in Figure 2.

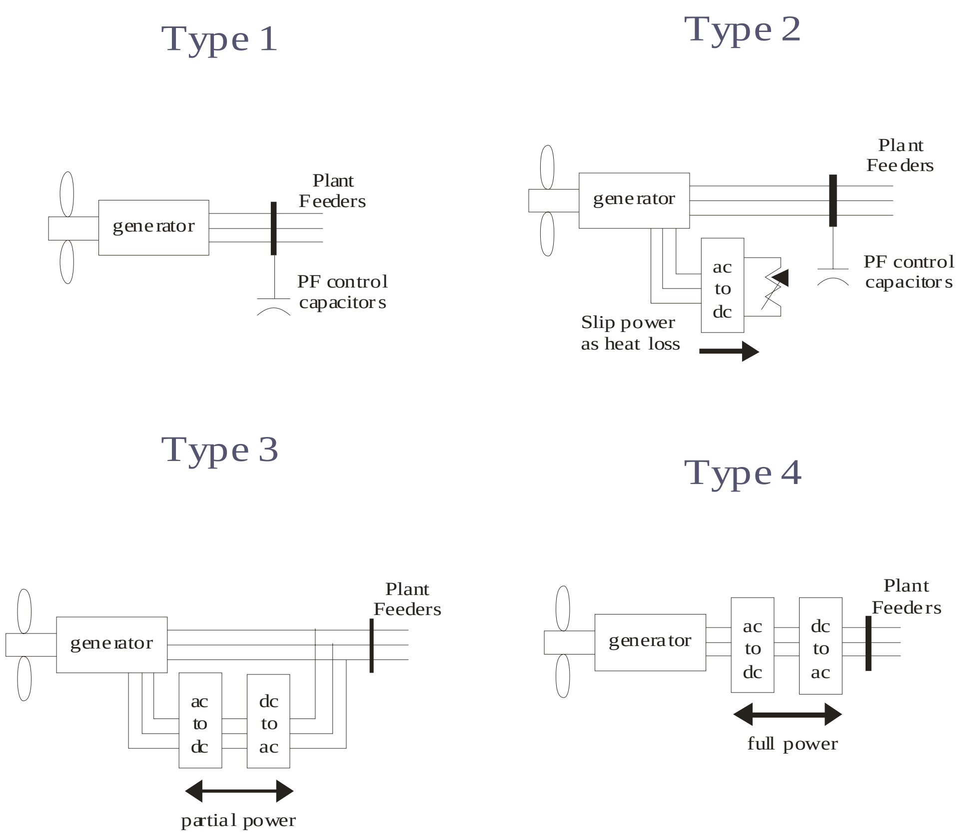

Figure 2: WECC Standard Wind Turbine Model Types.

2.2 GE PSLF WTG Models

From a system perspective, there are some important differences between these four types of WTGs. GE PSLF users manual includes different sets of default control models that can be used to build dynamic models of WTG for transmission planning studies. Table 1 list the GE PSLF model names and the corresponding components of the WTG, proposed in GE WTG Modeling Version 3.3. The detailed control block diagrams are also shown in GE PSLF users manual.

Table 1: GE PSLF Control Models for WTG

Type of WTG	PSLF Model Name	WTG Component	Explanation
Type 1	motor1	Induction generator	Induction machine represented in load flow working case as a generator
Type 2	genwri	Conventional-technology wound rotor induction (WRI) machine	Need to be used with an external field resistor
	exwtg1	External field resistor for the WRI	Normally, the resistor is electronically controlled (with a PWM IGBT circuit). The function of this control is to provide a much more steady power output from the wind turbine.
	wndtrb	Wind Turbine Model	Provides a simple representation of a complex electro-mechanical system to extract as much power from the available wind as possible without exceeding the rating of the equipment
Type 3 (Note: GE has published different version of Type 3 modeling using the same model names)	gewtg	Generator/Converter	Equivalent to the generator and the field converter and provides the interface between the WTG and the network
	exwtge	Electrical (Converter) Control Model	Dictates the active and reactive power to be delivered to the system based on inputs from the turbine mode and from the supervisory Var controller.
	wndtge	Wind Turbine and Turbine Control Model	It provides a simplified representation of the relevant controls and mechanical dynamics of the wind turbine.

2.3 Reactive Power Characteristics

Type 1 machines operate in a very narrow speed range, and always consume reactive power during operation. The reactive power consumption is a function of active power production and grid conditions, and cannot be controlled. Consequently, both the reactive power consumption of the generator *and* the reactive power requirements of the grid, must be supplied by additional equipment – usually switched shunt capacitors.

Type 2 machines have wider speed variation and tend to exhibit less fast active power fluctuation than type 1 machines, but have similar reactive power characteristics. Under load, the machine consumes reactive power equal to approximately half of the MW output.

Type 3 and Type 4 machines use substantial power electronics to provide wider speed range and finer control of active power production. The power electronics also inherently provide the ability to produce or consume reactive power. It is largely controllable independent from the active power production. In this regard, these machine resemble conventional synchronous generators with excitation systems and automatic voltage regulators (AVR). The details of performance are different between manufacturers. Generally, wind plants with Type 3 or Type 4 generators have the ability to provide relatively fast voltage or power factor control. The ways in which different manufacturers control and coordinate the reactive power production and balance differ. The great majority of wind generation built in the US last year was of Type 3 or 4.

2.4 Low Voltage Ride-Through (LVRT)

Figure 3 shows the WECC LVRT performance requirements and the PSLF implementation used in this study. For Type 3 and Type 4 WTGs, the ability to tolerate severe low voltages is primarily an issue of control and toughening of the power electronics necessary for operation of the wind turbines. For Type 1 and Type 2 machines, LVRT capability is derived from increased robustness of auxiliaries and contactors. It is important to recognize that LVRT capability and compliance is specific to voltage deviations, during and immediately following grid faults and disturbances. LVRT compliance does not guarantee that wind plants will remain stable following severe upsets.

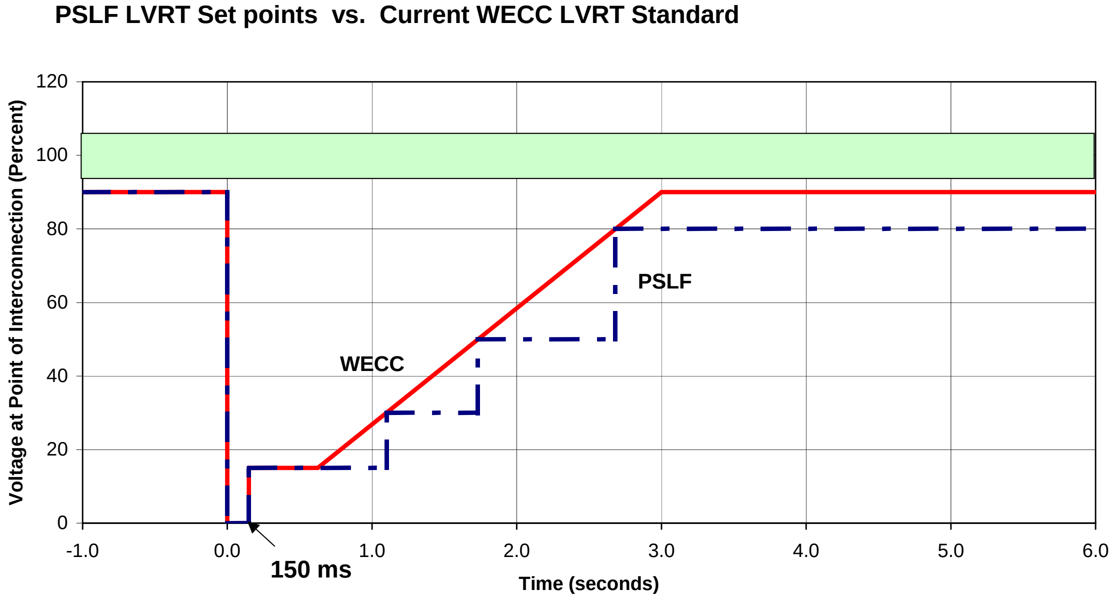

Figure 3: LVRT Requirements and Modeling.

3. Generator Protection Model

WTGs may be tripped for voltages and frequency values that exceed specified thresholds for specified time durations. Both the voltage and frequency trips should include a circuit breaker time of, typically, 0.15 seconds. In particular, the low voltage tripping will be set to meet LVRT requirements. WTGs from different manufactures may have different protection model.

GE PSLF has provided methods to simulate the protection model for types 2, 3 and 4 of WTG models.

Note, particularly, for the GE 1.5 MW WTG, the measurement point of the generator protection is the terminals of the generator; for the GE 3.6 MW WTG, the measurement point is at the high side of the unit step-up transformer.

3.1 Use Generator/Converter model in Version 3.3 WTG model

Table 2 illustrates the GE PSLF variables corresponding to the “gewtg” control model for the Type 3 WTG model provided in GE WTG model Version 3.3. The LVRT settings used in this study are also listed in Table 2.

Table 2: Voltage trip level setting in “gewtg” model of GE WTG model version 3.3

EPCL Variable	Tripping Level	Description
dVtrp1	-0.15	Delta voltage trip level, p.u.
dVtrp2	-0.25	Delta voltage trip level, p.u.
dVtrp3	-1.0	Delta voltage trip level, p.u.
dVtrp4	0.1	Delta voltage trip level, p.u.
dVtrp5	0.15	Delta voltage trip level, p.u.
dVtrp6	0.3	Delta voltage trip level, p.u.
dTtrp1	10	Voltage trip time, sec. (10 for no tripping)
dTtrp2	0.15	Voltage trip time, sec.
dTtrp3	0.01	Voltage trip time, sec.
dTtrp4	1.0	Voltage trip time, sec.
dTtrp5	0.1	Voltage trip time, sec.
dTtrp6	0.02	Voltage trip time, sec.

3.2 Use user-defined model in Version 3.4 WTG model

In GE PSLF WTG model Version 3.4, the WTG protection relay can be modeled through a standard user-written (EPCL). Generator protection model (**gpwtg.p**) is available in GE PSLF for modeling voltage and frequency tripping. WTG from different manufactures can be modeled using different EPCL protection models. The user-defined protection model can be used for both Types 2 and 3 WTGs.

The voltage trip levels are similar to those shown in Table 2. The typical frequency trip levels and durations based on specifications for a 60 Hz, 1.5 MW unit are shown in Table 3.

Table 3: Typical WTG Generator/Converter Frequency Trip Levels and Times (for 60 Hz. systems)

f (Hz.)	freq. [p.u.]	Time [sec]
57.5	0.96	30
56.5	0.94	.02
61.5	1.025	31
62.5	1.04	.02

Appendix G

Tehachapi Transmission Plan

California's largest potential for the development of wind generation is the Tehachapi area, which lies at the southern end of the San Joaquin Valley in the mountainous region between Bakersfield and Mohave. It is expected that at a minimum 4,350 MW of wind generators could be installed in this area. As a result, the Tehachapi Collaborative Study Group (TCSG) was formed in 2004 to develop a comprehensive transmission development plan for the phased expansion of transmission capabilities in the Tehachapi area. The California Public Utilities Commission (CPUC) Staff coordinated the TCSG while Southern California Edison Company (SCE) sponsored the project pursuant to the terms of the CAISO's Large Generator Interconnection Procedures.

The first report from the TCSG was issued to the CPUC in March 2005. In that report, the TCSG identified a number of alternatives for the transmission infrastructure and recommended further study be conducted in order to select the best expansion plan. A second report was issued in April 2006, which narrowed and refined the transmission infrastructure alternatives submitted in the first report. The second report also recommended that in order to facilitate completion of the planning process further detailed technical studies of the alternatives were to be performed by the CAISO.

The CAISO studied the Tehachapi Transmission Project as part of its CAISO South Regional Transmission Plan for 2006 (CSRTP-2006) in full collaboration with SCE and other CSRTP-2006 participants. The studies were "clustered" which allowed the CAISO to collectively study the system impacts of a group of Interconnection Requests, rather than evaluate each potential Generation Facility individually. Thus, by "clustering" the interconnection request, a least-cost solution for the transmission infrastructure was determined to interconnect up to 4,350 MW of planned generation projects in Tehachapi area to the CAISO Controlled Grid. This transmission expansion plan was approved by the CAISO Board in January 2007.

Benefits of the Tehachapi Transmission Project

The benefits of the Tehachapi Transmission Project as approved by the CAISO Board in January 2007, are as follows:

1. The Tehachapi Transmission Project is the least-cost solution that reliably interconnects 4,350 MW of generating resources in Tehachapi area;
2. The Tehachapi Transmission Project also addresses the reliability needs of the CAISO Controlled Grid due to projected load growth in Antelope Valley area as well as helps to address South of Lugo (SOL) transmission constraints – an ongoing source of reliability concern for the Los Angeles (LA) Basin;
3. The Tehachapi Transmission Project facilitates the ability of California utilities to comply with the state mandated Renewable Portfolio Standard (RPS) by providing access to planned renewable resources in the TWRA – also see points 6 and 7 below;
4. The Tehachapi Transmission Project is expected to provide economic benefits to the CAISO ratepayers mainly by providing access to wind and other efficient generating resources under development in TWRA;

5. The Tehachapi Transmission Project makes it possible to expand the transfer capability of Path 26 in the near future with a low cost upgrade of PG&E’s portion of Midway-Vincent Line 3;

6. The Tehachapi Transmission Project will be used by other projects in TGQ queued beyond the start date of the CSRTP-2006 for low-cost interconnection to the ISO Controlled Grid;[6] and

7. Although the detailed planning has not yet been performed, the Tehachapi Transmission Project lays the groundwork for the integration of large amounts of planned geothermal, solar, and wind generation in Inyo and northern San Bernardino counties with potential future 500 kV additions from the WindHub Substation (one of Tehachapi Transmission Project’s substations) to the Kramer Substation.

   The Tehachapi Transmission Project will accommodate all targeted generation projects in the Tehachapi Area Generator Queue. However, sufficient flexibility is built into the rollout of the Tehachapi Transmission Project to reasonably respond to changes in the magnitude and the location of generation resources in the area.

Project Description and Schedule

Figure 1 depicts the major components of the Tehachapi Transmission Project at full build out in 2013, while Table 1.2 sets forth the schedule for the rollout of the major components. Due to the expansive nature of the Tehachapi Transmission Project, the components of this infrastructure will be developed and put into service over a five-year period starting from 2008. The addition of each component allows added access to TGQ generation as well as ensures compliance with reliability standards given projected load growth in the area. This schedule is intended to be flexible and subject to change in response to actual wind generation development in the TWRA. Around 1,260 MW of such generation is already in TGQ as of December 1, 2006. 17 Special rate treatment for such radial collectors systems may be provided from both the CAISO and the CPUC consistent with their respective regulatory authority.

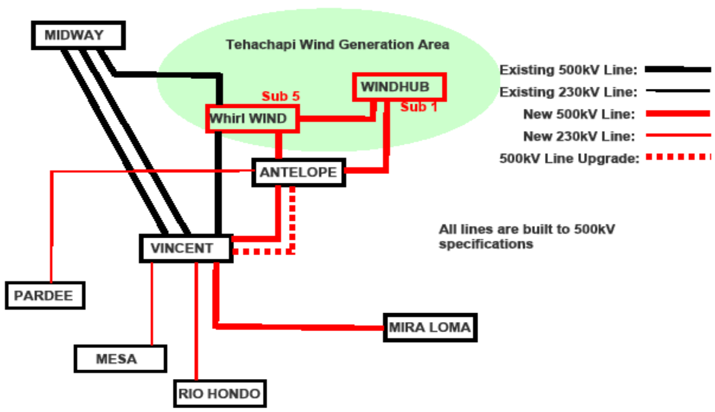

Figure 1: Proposed Transmission Upgrades

New or Upgraded Substations:

Three new substations would be constructed and used as collector stations for the wind farms in the TWRA: WindHub, Whirl Wind and HighWind Substations. The first two of the three new substations are part of the network component of the overall plan of service. The cost of the third substation (Highwind) is the responsibility of the wind developers and not included in the Tehachapi Transmission Project plan.

WindHub 500/230/66 kV will include up to four 500/230 kV transformer banks, four breaker-and-half 500 kV bus positions, six initial breaker-and-half 230 kV bus positions, static voltage support devices, and dynamic voltage support if necessary. Additional equipment will be added as wind generation develops in the region.

Whirl Wind 500/230 kV will include up to two 500/230 kV transformer banks, four breaker-and-half 500 kV bus positions, three initial breaker-and-half 230 kV bus positions, static voltage support devices, and dynamic voltage support if necessary. Also includes loop in of Midway-Vincent #3 line to connect the substation to the grid. Additional equipment will be added as wind generation develops in the region.

Upgrades to existing substations:

- The Pardee 230/66 kV substation will be upgraded by outfitting existing 230 kV line position.
- The existing Mira Loma 500/230/66 kV substation will be upgraded by outfitting existing 500 kV line position.
- The existing 230/66 kV Antelope Substation will be expanded to include a new 500 kV switchyard, additional 230 kV line positions and static and dynamic voltage support.
- The existing 500/230 kV Vincent Substation will be expanded to include additional 500 kV and 230 kV line positions, additional static and dynamic voltage support and additional 500/230 kV bank capacity.
- The Mesa 230/66 kV substation will be upgraded by outfitting existing 230 kV line position.
- The Gould 230/66 kV substation will be upgraded by outfitting existing 230 kV line position.

New or Upgraded Transmission Lines:

- New 25.6-mile 500 kV transmission line between Antelope and Pardee substations initially operated at 230 kV. This line is also known as Phase 1-Segment 1 of the original Antelope Transmission Project. Construction to 500 kV specifications with initial operation at 230 kV is required to maximize the capability of limited transmission corridors and minimize environmental impacts associated with multiple 230 kV lines and/or multiple teardown and rebuild activities. Actual operation of 500 kV will be determined by the amount of generation build out in the system and changes to system conditions.

- New 25.6-mile 500 kV transmission line between WindHub and Antelope substations. This line is also known as Phase 1-Segment 3 of the original Antelope Transmission Project and will initially operate at 230 kV.

- Two new 500 kV transmission lines between Antelope and Vincent substations. The initial 500 kV transmission line will be approximately 21.0 miles built on new right-of-way mostly adjacent to the existing right-of-way. This line is also known as the Phase 1-Segment 2 of the original Antelope Transmission Project and will initially operate at 230 kV. This new transmission line is primarily required to meet the reliability needs of the CAISO controlled grid due to projected load growth in Antelope Valley. The second 500 kV transmission line will be approximately 18.0 miles built on existing right-of-way replacing the existing Antelope-Vincent and Antelope-Mesa 230 kV transmission lines. This transmission line will also be initially operated at 230 kV.

- New 75-mile 500 kV transmission line between Vincent and Mira Loma substations. This transmission line is required to eliminate the South of Lugo transmission constraints, which have been a source of ongoing reliability concern for the LA Basin, especially in light of projected load growth in Mira Loma area, and is planned to go into service by 2012 timeframe. This line will utilize the existing Vincent-Rio Hondo No.2 230 kV transmission line (portion already built to 500 kV standards), portion of the existing Antelope-Mesa 230 kV South of Vincent, portions of existing idle 230 kV transmission line segments, and portions of new construction between the Mesa area and Mira Loma area. Between Vincent and the northern boundary of the City of Duarte (adjacent to Angeles National Forest), the transmission line will be constructed as single-circuit 500 kV specifications. From this point to the Mira Loma area, the transmission line will be constructed as double circuit 500 kV specifications to maximize the capability of limited corridors and to minimize environmental impacts associated with multiple 230 kV lines and/or multiple tear-down and rebuild activities.

- New 32.5-mile 500/230 kV transmission line between Vincent and Rio Hondo is required to replace the existing Vincent-Rio Hondo No.2 230 kV transmission line that was utilized for the new Vincent-Mira Loma 500 kV transmission line. This line will utilize portion of existing Antelope-Mesa 230 kV transmission line and will be built to 500 kV specifications to maximize capability of limited transmission corridors, avoid waste and minimize environmental impacts associated with multiple 230 kV transmission lines and/or multiple tear-down and rebuild activities. As discussed above, such construction standard will allow for a future low cost upgrade to 500 kV operation.

- New 14-mile 500 kV transmission line between proposed WhirlWind and the upgraded Antelope substations.

- New 42-mile 500/230 kV transmission line between Vincent and Mesa substations. Between Vincent and the Gould substation areas, this line will be built to 500 kV specifications to maximize capability of limited transmission corridors and minimize environmental impacts associated with multiple 230 kV transmission lines and/or multiple tear-down and rebuild activities and to allow for future low cost upgrade to 500 kV operation.

Table 1: Tehachapi Transmission Project Plan of Services

Major Transmission Facilities	Planned In-Service Date
Antelope – Pardee 230 kV Line (500 kV Specifications) & Antelope Substation Expansion	Dec 2008
Antelope – Vincent 230 kV Line #1 (500 kV Specifications)	Mar 2009
WindHub Substation	Mar 2009
Antelope – WindHub (also known as Substation 1) 230 kV Line (500 kV Specifications)	Mar 2009
Antelope – Vincent 230 kV Line #2 (500 kV Specifications)	Mar 2011
LowWind 500/230 kV Substation (also known as Substation 5) with Loop in of Midway – Vincent #3 500 kV line	Aug 2011
Antelope – LowWind 500kV line	Aug 2011
WindHub Substation 500 kV Upgrade	Mar 2011
Antelope Substation 500 kV Upgrade	Mar 2011
Vincent Substation 500 kV & 220 kV Upgrade	Sep 2011
LowWind – WindHub 500 kV line	Oct 2011
Replacement of Vincent – Rio Hondo No. 2 230kV line	Nov 2011
Vincent – Mira Loma 500 kV line	Apr 2012
Vincent – Mesa 500/220 kV Line and Mesa Substation Work	Nov 2013

List of Reactive Devices Required In The Tehachapi Area

In order to support 4,350 MW of generation in the Tehachapi area, a significant amount of reactive devices would be required. So far, studies done using a summer peak scenario identified the requirement for 2,000 MVARS of static shunt capacitors and 600 MVARS of SVC.

Static MVARS Requirement --- 2,000 MVARS

- Vincent 500kV 400 MVAR shunt
- Antelope 500kV 400 MVAR shunt
- Sub. 5 (Whirlwind) 500 kV 2x200 MVAR shunt
- Sub. 5 (Whirlwind) 230 kV 2x100 MVAR shunt
- Sub. 1 (WindHub) 500 kV 2x200 MVAR shunt

- Sub. 1 (WindHub) 230 kV 2x100 MVAR shunt

Dynamic MVAR Requirement – 800 MVARS

- Vincent 500 kV 600 MVAR SVC
- Antelope 500 kV 200 MVAR SVC

Tehachapi Transmission Project Plan of Service
(Routes shown on next page are for illustration purposes only)

SYSTEM ARRANGEMENT
FINAL TEHACHAPI TRANSMISSION PLAN