ASSESSMENT OF RELIABILITY AND OPERATIONAL ISSUES FOR INTEGRATION OF RENEWABLE GENERATION

In Support of the
California Energy Commission
2005 Integrated Energy Policy Report

CONSULTANT DRAFT REPORT

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Foreword

This draft report is a work-in-progress that has been prepared to provide background for the California Energy Commission's (Energy Commission) second workshop on Transmission and Renewable Integration Issues (scheduled for May 2, 2005) and has not had the benefit of stakeholder review. This draft report is intended to foster discussion and obtain stakeholder feedback for incorporation in a final report due in June 2005.

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Project Background and Purpose

California has led the nation in the development of its renewable resources. The California Renewables Portfolio Standard (RPS) was passed by the California legislature in September 2002 mandating energy production from renewable resources to account for 20 percent of the annual energy production by 2017. In May 2003, the Energy Commission, California Public Utilities Commission CPUC, and California Power and Conservation Financing Authority (California Power Authority) called for the acceleration of renewable integration setting the goal of 20 percent by 2010 with the adoption of the Energy Action Plan.

Renewable resources offer the benefits of price stability, resource diversity, reduced dependence on fossil fuels, and reduction in environmental impacts. These benefits are important for California consumers. Substantial increase in renewables requires proactive identification, analysis, and development of options to address potential operational and resource integration issues that might otherwise hinder and delay achievement of statewide policy goals for renewables development. Integration issues may result from the location of the resource, as renewables are frequently located remote from customer loads and require the development of new transmission and interconnections to deliver the output of renewable resources to consumers, and from the intermittent nature of certain renewable resources and require assessment and development of strategies to address operational and reliability integration issues.

There are many strategic policy issues related to reliability and operations for integration of renewables in California. Historically, these issues have been addressed individually and often litigiously. As the type and level of renewables in the energy mix increases, the number of reliability and operational issues are expected to increase. To meet the objectives of the RPS and accelerate development of renewables, California needs a predictable policy framework for operational integration of new renewables.

The present study seeks to learn from the experiences and best practices of other regions that have integrated large amounts of renewables and assess the applicable lessons they provide for California, in establishing a stable policy framework for addressing the operational and reliability issues for renewables integration. The objectives of this proposed study are to:

1. Review and assessment of papers and studies related with integration of renewable resources.

2. Catalog experiences associated with renewables integration in California and other selected regions and determine best practices and lessons learned, which will foster renewables integration in California.

3. Catalog California-specific operational integration and reliability issues through dialogue with key utilities, stakeholders, and independent system operators.

4. Conduct stakeholder workshops to seek input and validate findings.

5. Summarize and quantify operational issues, where possible.

6. Evaluate alternatives to address reliability and operational integration issues, including resource management, operating procedures, and regulatory policies. Assess pros and cons for alternative policy options.

7. Prepare a final report that will integrate with the Energy Commission's Integrated Energy Policy Report (IEPR) process.

Recap of the February 3 Stakeholder Workshop

On February 3, 2005, a workshop was held to review the project findings from items 1, 2 and 3 mentioned above in an open forum with all stakeholders.

The outcome of the workshop was as follows:

- Stakeholders confirmed the adequacy of the list of issues identified; no additional issues were identified.

- Concern was expressed regarding the characterization of shadow reserves on the E.ON-Netz grid, in Germany, and the current status of low voltage ride-through standards being developed in the United States.

- Comments were made that the reliability and operational issues identified are attributable to all resources and stakeholders and not the sole responsibility of renewable developers.

Comments Filed with the Energy Commission Regarding the Workshop

Written comments by the entities listed below were filed with the Energy Commission regarding the February 3 workshop and January 27 background report entitled, "Assessment of Reliability and Operational Issues for Integration of Renewable Resources." The project team greatly appreciates each organization's time and effort to submit comments and has endeavored to take into account and address these comments in the work effort being developed for the May 2, 2005, workshop. Organizations that filed comments with the Energy Commission were:

- American Wind Energy Association
- California Wind Energy Association
- Consortium for Electric Reliability Technology Solutions
- PPM Energy
- Southern California Edison

The following provides an extracted summary of the comments filed by each organization.[1] Appendix A includes a copy of each party's full written comments.

American Wind Energy Association (AWEA)

- AWEA applauds the Energy Commission's effort to define and refine the operational issues associated with wind integration.

- In no way, however, does AWEA believe that the current record in this proceeding supports any findings about whether policy, procedural or regulatory changes are warranted.

- AWEA recommends that the next steps identified in the Project – specifically the development and risks of various policy changes – be suspended immediately.

- Rather AWEA recommends that the Commission embark upon a comprehensive and detailed study of the impacts of high-penetration renewables development, as was done by the New York State Energy Research and Development Authority (NYSERDA). Policy alternatives should only be considered in the light of credible, detailed analysis.

California Wind Energy Association (CalWEA)

- The Project is not focused. It does not distinguish between relatively routine issues (such as voltage regulation) that are being or will be handled in the appropriate technical forums and "problems" that are not being adequately addressed.

- The Project suffers from an alarmist quality and perpetuates myths (e.g., that wind requires dedicated back-up resources).

- The background report reflects past historical issues, such as insufficient volt ampere reactive (VAR) support and lack of wind forecasting, without adequately accounting for technological advances and evolving market rules which have obviated many of those issues.

- The issues list includes many issues that are not appropriately characterized as “renewables operational integration issues” because they are issues that are not caused by, or are not uniquely associated with, renewables. The IEPR process should address (and maybe already is addressing) these issues, but it should not be done in the context of renewables operational issues. Treating regulation and integration issues in isolation with respect to wind is not productive.

- The Project appears to be disconnected from, and uninformed by, the PIER program’s excellent work on the RPS Integration Cost Studies, which is on-going. The efforts should be coordinated.

- The Project appears to be uninformed by the work well underway at the Federal Energy Regulatory Commission (FERC), the Utility Wind Interest Group, Western Electricity Coordinating Council (WECC), and elsewhere. Far more comprehensive summaries of this work, as well as up-to-date analyses on many of these issues, are available but not reflected in the Project.

- In addition, CalWEA provided a response to each of the four questions posed to the Stakeholder panel at the February 3 workshop.

CalWEA recommended the following:

- The IEPR’s discussion of renewables integration/operational issues should draw from the California-specific, detailed analyses that the Public Interest Energy Research (PIER) program team has conducted and continues to conduct in many of these topic areas, rather than from this Project’s laundry list of potential issues drawn from myriad studies that may or may not be relevant to California’s current situation.

- This Project should be reconsidered and refocused for the 2006 IEPR process. The effort should focus on the system as a whole, with an eye toward optimizing grid operations in view of the state’s mandated renewable energy goals. The effort should consider the most efficient integration of all resources (and large single loads), separating out issues associated with resource or technology characteristics and issues caused by contractual constraints.

***Consortium for Electric Reliability Technology Solutions* (CERTS)**

- The January 27 background report was a work in progress document, a final report is due in June 2005.

- The objective is to present a factual review of industry experiences and concerns, and identify the reliability and operational issues that would have to be dealt with as California integrates renewable generation to meet the RPS.

- The purpose of the scheduled workshop was to present research findings to date in an open forum with all stakeholders. The planned outcomes from the workshop were to: validate list of issues identified for the project, identify if there are any gaps in the list of issues, obtain stakeholder feedback on description of issues and any suggested modifications, and determine if the project is headed in the right direction and is adequately focused.

- Factual basis for two aspects of the materials developed by CERTS, namely E.ON Netz experience and Voltage were challenged as being misrepresentations. CERTS team provided specific references and documentation for the sources relied on in developing the materials for the workshop.

PPM Energy

- PPM Energy comments on the February 3 workshop, CERTS February 14 response, and provides a summary of PPM's Energy representative meeting with E.ON representatives on February 14 in Germany.

- PPM Energy challenges several of the underlying themes in the presentation made by the Electric Power Group at the February 3 IEPR Workshop on Transmission-Integration (Docket 04-IEP-1F).

- Specifically, the references to the debates around the "low voltage ride through" (LVRT) standards are inappropriate given that consensus on this topic is near at hand in a number of technical forums (WECC, FERC, and the North American Electric Reliability Council, or NERC).

- Secondly, the references to the E.ON experience in Germany imply a level of operating reserves (to use the American nomenclature) that is just not accurate.

- PPM Energy looks forward to a robust process in the remainder of the 2005 IEPR to clarify these specific issues as well as advance the general discussion on this important generic subject.

Southern California Edison (SCE)

- The list of issues that have been identified are accurate and the study appears to be headed in the right direction.

- To the extent there are operational, planning, and interconnection concerns, we believe they need to be addressed sooner rather than later, so that effective methods and approaches can be developed and implemented to fulfill the state's aggressive renewable objectives, without jeopardizing the quality, reliability, and cost of the power Californians use.

- Given that the majority of renewable and wind potential is located in or near SCE's service territory, coupled with the desire to significantly increase renewable resources, there is a high likelihood that SCE will be required to integrate levels of intermittent and non-dispatchable resources far in excess of our own obligations. As such, the integration issues addressed by the study will likely be greatly amplified for SCE compared to the state's other electric systems.

- Several participants commented that "this process should not force wind resources to resolve the existing problems with the systems as a whole." SCE does not believe that the study is requiring the new renewable resources to correct the problems associated with the system. However, given the anticipated large increase in these non-dispatchable and intermittent resources, we do need to address the system reliability and operational issues, along with methods to accommodate or correct any adverse impacts.

- The study should look at the operational issues associated with other types of renewable resources as they may encompass different integration issues and remedies.

- In addition, SCE provided a response to each of the four questions posed to the Stakeholder panel at the February 3 workshop.

May 2, 2005 Workshop – Purpose, Agenda and Expected Outcome

The purpose of the scheduled workshop is to review the project team's work effort since the February 3 workshop and present preliminary analysis results in an open forum with all stakeholders.

The expected outcome from the workshop is to achieve stakeholder buy in and support for the following:

- List of solutions and the issues they mitigate
- Owners of the proposed solutions
- Metrics and monitoring related to the solutions
- Research requirements
- Also, comments and feedback from stakeholders and the proposed solution owners will be solicited.

May 10, 2005 Workshop Agenda (subject to revision prior to workshop date)

1. A CERTS member will open the workshop session and provide the background and scope of the project

2. AWEA or other wind industry representative will discuss the findings from E-ON Netz visit

3. A WECC member will give an update on WECC's LVRT standard

4. A representative from CERTS will cover the following:
   - Recap of project objectives and activities
   - Purpose of today's workshop
   - Renewable resource development and operating characteristics
   - Stakeholder comments from the February 3, 2005 workshop
   - Summary list of issues and brief description
   - Operational and reliability issues for California
     - Quantifying issues, where possible
     - Review of resource attributes
   - Solution options and action required
     - Summary of solutions
     - Review of individual solution, identifying solution owners, required research and metrics
     - Priorities

5. Stakeholders panel discussion on the following:
   (Panel make-up – Suggested solution owners (e.g., control area operator(s), policy maker and three utility representatives)
   - Determine if the suggested solutions and priority lists are complete
   - Determine if there is agreement of the suggested research and metrics for monitoring performance
   - Panel's reaction to the suggested action items for the state agencies
   - Would the panel support and sponsor the implementation of the solutions
   - How would you go about solution implement
   - Comments on the time required to implement all or some of the solutions

6. Open comment period from interested stakeholders
   (Five minute limit for each stakeholder)

7. Next Steps
   - Review and incorporate stakeholder feedback
   - Draft report to Energy Commission Staff by June 1
   - Final Energy Commission report by June 15 for integration with the Energy Commission's IEPR

Preliminary Analysis of Reliability and Operational Issues

Pursuant to the February 3, 2005 workshop comments and stakeholder feedback, the list of reliability and operational issues has been revised and updated. The updated list of issues is below.

1. Load Following
2. Minimum Loads
3. Reserves and Ramping
4. Load and Generation Forecast Variability
5. Storage
6. Frequency and Voltage Requirements
7. Resource Deliverability
8. Transmission Import Capability
9. Planning and Modeling

The issues that were dropped based on the February 3, 2005 workshop are listed below. Note that these issues are either technical in nature, which are being addressed through standards and guidelines, or uncertain as to the magnitude and timing.

- Compliance with NERC Standards
- Voltage Support
- Retirement of Older Plants

For each of the remaining nine issues, each issue is outlined and summarized below.

Summary Description of Issues

1. Load Following (LF)
   - Current LF demand is significant.
   - The LF demand is increasing.

- Supply is eroding due to new generator attributes and aging plant retirements.

2. Minimum Loads
   - High levels of off-peak energy result in operating problems for the control area operator (CAO), Transmission System Owner (TSO), and load-serving entity (LSE).
   - Exports of excess generation may not always be an option.
   - Managing minimum loads requires off-peak energy production curtailments.

3. Reserves and Ramping
   - Intermittent resources production is generally less than nameplate capacity and highly variable.
   - Some intermittent resource types do not provide the same operating attributes as conventional generation resources for meeting reliability standards.

4. Load and Generation Forecast Variability
   - Forecast accuracy affects reserve requirements.
   - Online reserves may be either too high or too low depending on load and generation production forecast variability.

5. Storage
   - Storage not available during spring run-off months to mitigate minimum load condition.
   - Additional storage and load control facilitate integration of intermittent resources.

6. Frequency and Voltage Requirements
   - Frequency and voltage ride-through standards for generation have been adopted by WECC.

7. Resource Deliverability
   - Interconnections standards do not address deliverability capability to move power to different regions.
   - Full benefit and integration of renewable resources may not be achieved without addressing deliverability.

8. Transmission Import Capability
   - Reduced inertia and variability in generating performance could negatively impact existing transmission path ratings into California and throughout WECC.

9. Planning and Modeling
   - Detailed generator modeling data is needed to support studies
   - Off-peak system conditions need to be studied to analyze transmission system loadings and vulnerabilities.

Analysis of Issues

The project team obtained 2004 recorded data for analysis of the first four issues:

1. Load Following
2. Minimum Loads
3. Reserves & Ramping
4. Load and Generation Forecast Variability

Issues 5 through 9 involve data, technical evaluations and modeling that is specific to utilities and control areas. However, the project team does make observations on what needs to be done and by whom as a follow up to this study.

A summary of the analysis for the first four issues follows below. The analysis is organized by defining the issue, outlining the focus and methodology for analysis, presenting the results, and providing findings.

Load Following

Issue
The CAO is responsible for ensuring that the control area is operated within WECC and NERC standards. This includes meeting minute to minute changes in both load and generation on the grid to constantly balance load and generation. There are three time periods of interest in addressing load following:

1. Frequency and tie-line regulation (automated generation control, or AGC) is addressed by controlling generation in the time period ranging from seconds to ten minutes;

2. Load following (so-called five or ten minute dispatch) addresses the load and generation changes which occur in the time period ranging from minutes to several hours; and,

3. Unit commitment and day-ahead scheduling address the changes in load and generation anticipated in the daily planning processes, typically several hours in advance to 24 hours in advance.

Focus
Previous studies (Energy Commission and others)[2] have indicated that for the time period of frequency and tie-line regulation, the addition of renewable and intermittent generation have only a very small impact. Isolating the impact of renewable and generation variations from the variations in load (which are always occurring), indicate that the variations in generation are slower to occur, and frequently self-

canceling due to the numerical diversity of resources. For instance, second to second variation in the power output of an individual wind generator occurs for a variety of reasons. However, when many wind generators are connected to the grid, the individual short term variations are generally uncorrelated, and tend to cancel each other out, resulting in only a small impact on overall grid regulation needs.

For the longer time period variations, such as several hours or the diurnal patterns, the energy output of similar types of intermittent generation are correlated and can impact the control requirements on the system operator. For instance, solar generation exhibits a daily generation swing cycle, with low or no power (except for the case of supplemental firing) during the night-time hours, and near-full power during the daylight hours. This daily swing of power output, while predictable, must be managed in the context of the grid's requirement to balance generation changes minute to minute with the load changes. For wind generation, the variation in output is less correlated with the load, and varies with wind patterns and location of generating sites.

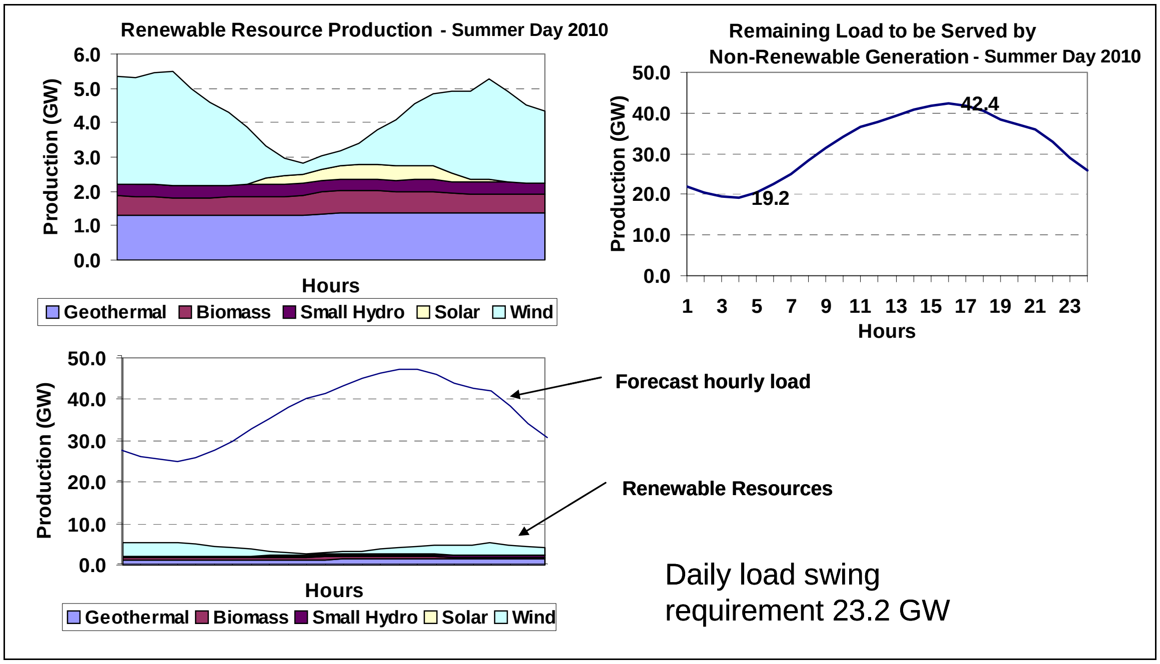
Methodology

To assess the potential impact of renewable generation on these daily load following requirements, a numerical assessment of the total daily swing in controllable generation was performed using historical hourly load patterns and historical generation production based on 2004 California Independent System Operator (CA ISO) data.

In the analysis it was assumed that renewable generation would be dispatched first, with all other non-RPS generation (including existing large hydro generation) dispatched thereafter. Relying on this assumption, it was possible for each forecast hour of 2010 to simply reduce the forecast hourly load by the forecast total RPS generation production estimate for that hour, resulting in a remaining load which would then be served by all other non-renewable generation. Figure 1 illustrates the construction of the residual load for 2010.

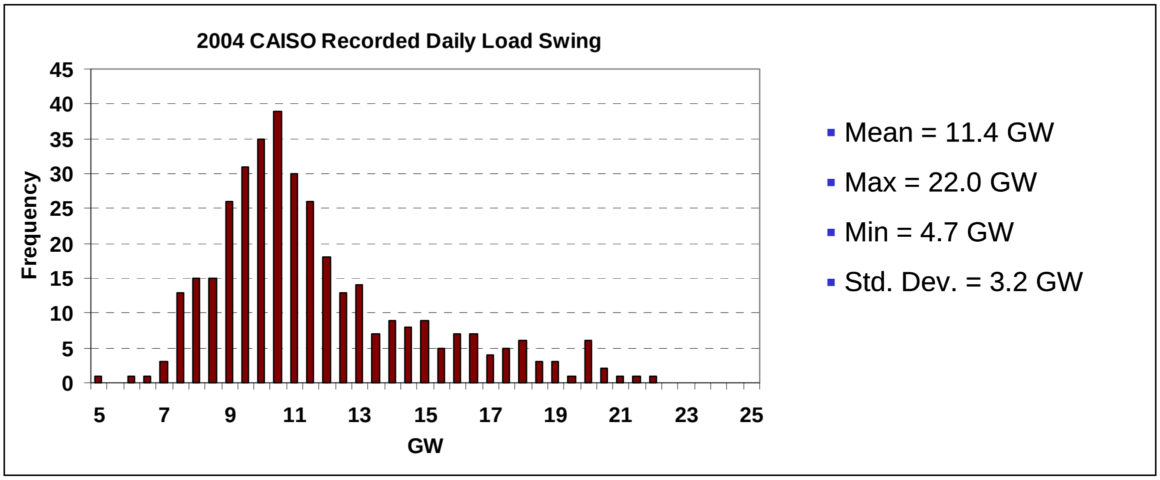
The data in this report for the figures and tables are drawn from the CA ISO hourly recorded data for calendar year 2004 for both load and renewable generation. For the year 2010 assessment, the recorded CA ISO 2004 hourly loads were scaled up to match the Energy Commission's forecast of the CA ISO area for 2010. For the 2010 forecast renewable energy production by resource type, the recorded 2004 hourly production records for each renewable type were scaled up based on the Energy Commission's estimate of projected incremental renewable resource additions in the CA ISO area.

Figure 1
Remaining Hourly Load (Adjusted for Renewables)



To establish a baseline for comparison of daily load swings, the CA ISO 2004 recorded hourly generation output of geothermal, biomass, small hydro, solar, and wind plants (representing the existing renewable portfolio) were subtracted from the CA ISO 2004 recorded hourly load data to develop remaining hourly load which would then have to be met by dispatching non-RPS generation. The daily swing from the minimum residual hourly load to the maximum residual hourly load represents the generation control range required for each day. By "bucketing" the daily controllable generation swing requirements for the entire year, a histogram of load following requirements was developed, in 500 MW increments, and is illustrated in Figure 2. For example, there were 39 days when the daily ramp was between 10,000 and 10,500 MW and one day when this ramp was between 21,500 and 22,000 MW.

Figure 2
2004 CA ISO Recorded Daily Load Swing



Forecast for 2010
To estimate the impact of the RPS portfolio on the future load following requirement, the CA ISO 2004 recorded hourly loads were scaled to the 2010 Energy Commission forecast level (for the CA ISO control area) using a load growth scaling factor of 5.2 percent. Next, using the hourly recorded production levels for the various renewable generation types, the 2010 production levels were developed by scaling each resource type to its 2010 forecast level. A detailed description of the methodology used to develop the estimates for renewable energy production for 2010 is included in Attachment B. Table 1 summarizes the 2004 and forecast 2010 production levels for each of the renewable generation types.

Table 1
Estimation of 2010 Renewable Production

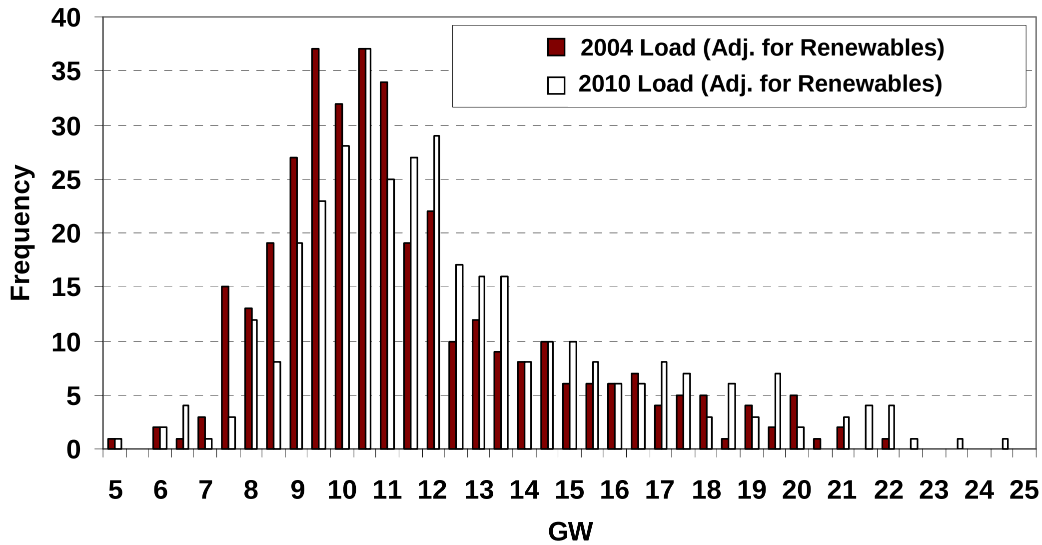
	CAISO Energy Mix (%)					
	2004 Recorded (GWh)	2004 Recorded (%)	2010 Acccelerated RPS (GWh)	2010 Acccelerated RPS (%)	2010 Total Renewable (GWh)	2010 Total Renewable (%)
	(a)	(b)	(c)	(d)	(a+c)	(e)
Biomass	3,261	17%	1,463	9%	4,724	13%
Geothermal	8,359	43%	3,671	22%	12,031	33%
Small Hydro	3,284	17%	0	0%	3,284	9%
Solar	708	4%	265	2%	973	3%
Wind	4,013	20%	11,440	68%	15,453	42%
Total	19,625	100%	16,839	100%	36,464	100%

Note: Numbers may not add due to rounding.

Analysis

Comparing the forecast 2010 daily swing requirement with the 2004 daily swing requirement, shown on Figure 3, illustrates that the maximum daily swing increases by nearly 2,200 MW, and the average daily swing requirement increases by about 1,000 MW.

Figure 3
Daily Load Following Requirement



2010 increase over 2004

- Mean = 1.0 GW
- Maximum = 2.2 GW
- Minimum = 0.7 GW
- Standard deviation = 0.4 GW

For the peak increase in daily swing requirement, the load growth from 2004 to 2010 accounts for 1,100 MW of the increase, while the growth in renewable generation accounts for the remaining 1,100 MW of increase. Similarly, the load growth accounts for 600 MW of increase in the average swing requirement, while the growth in renewable generation accounts for the remaining 400 MW.

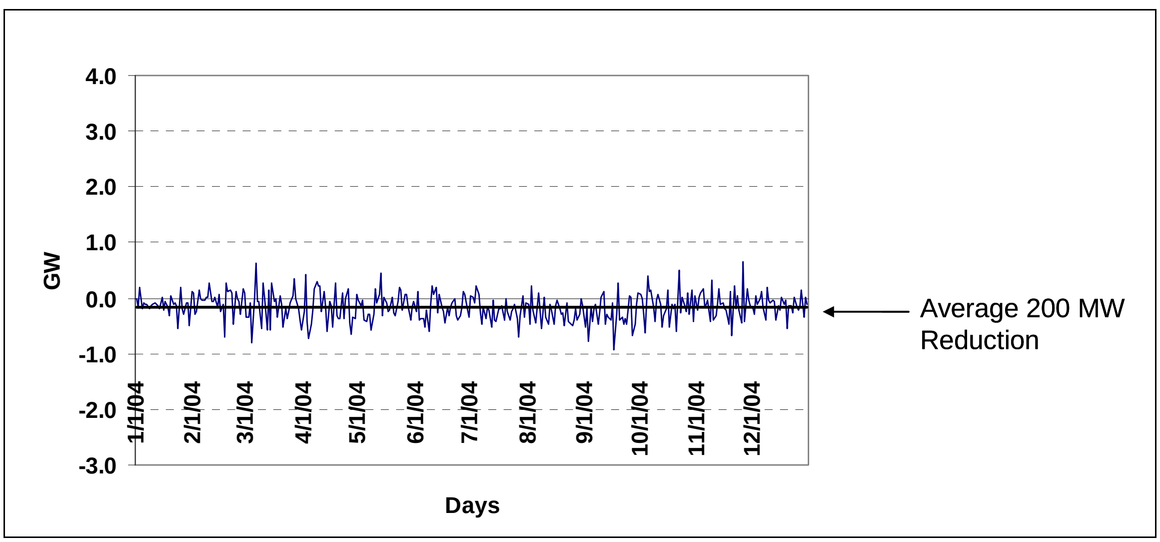
Discussion

The increase in renewable generation in the California energy mix will increase the magnitude of the daily swing to be served by controllable generation to meet WECC and NERC control performance standards. The level of the swing increase will be highly dependent upon the mix of renewable generation that ultimately serves

California's future load. For instance, based on the RPS assumptions, wind will play a dominant role in the increase in renewable energy sources, and wind is arguably the energy source which is least correlated to the daily load swing. Thus, with large amounts of wind energy in the future mix, the requirement for controllable generation will be larger. Given the size of California's electricity system, the increase in peak load swings are not significant. However, the pattern of load swings may be less predictable. If a less cyclic energy source, such as geothermal, were to provide the greatest amount of incremental energy supply, then lesser amounts of controllable generation would be required. If solar were to be a larger part of the mix (double the current forecast), the swings can be almost completely mitigated due to the high load and production correlation.

Recorded renewable production in 2004 and the Energy Commission scenario of forecast production in 2010 provide an example of how the load swing is influenced by the mix of renewable generation. The integration of the 2004 renewable production actually reduced the average daily load swing by 200 MW as illustrated in Figure 4 below. This figure presents the differential between the load swing without renewable generation and the load swing with renewable generation, with a higher daily load swing being portrayed as a positive value. Note that for 2004, the average of the daily load swings is negative, which means the load swings were reduced by the addition of renewable generation.

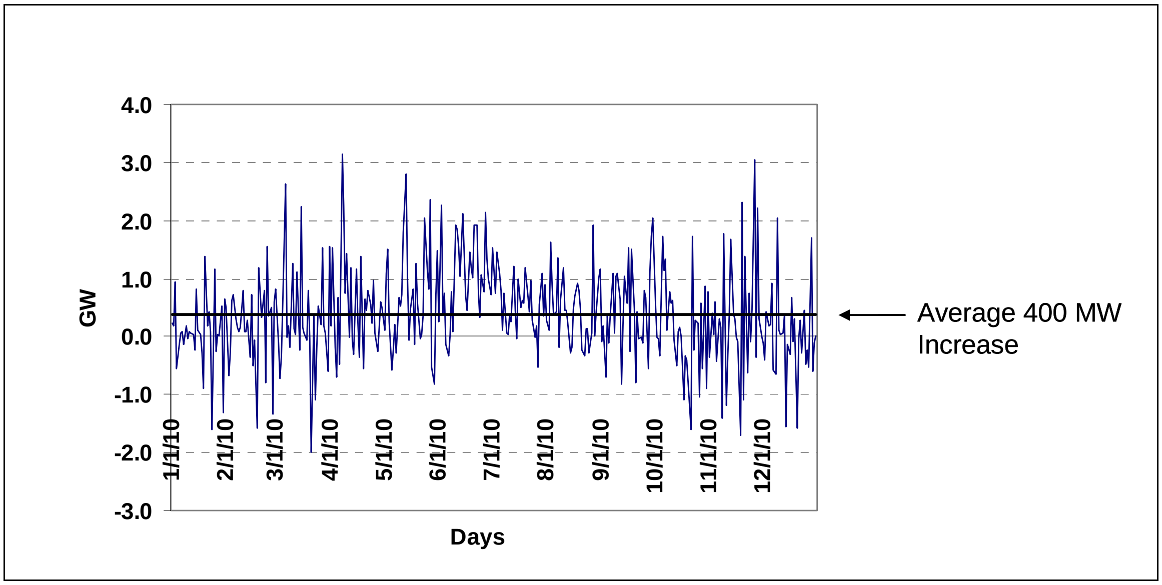
Figure 4
2004 Delta in Daily Load Swing (Adjusted for Renewables)



Resources which are somewhat positively correlated with the load including solar and small hydro amounting to 21 percent of the mix contributed to this reduction.

The 2010 assessment compared the difference in daily load swing given the integration of accelerated RPS generation in the 2005 to 2010 time period. Specifically, the difference compared the case assuming 2010 forecast chronological hourly load with recorded 2004 renewable production and secondly with forecast 2010 renewable generation. Integration of the RPS energy increased the daily load swing by 400 MW as demonstrated by the positive average daily load swing shown in Figure 5, below.

Figure 5
Change in Daily Load Swing with Accelerated RPS Generation



The increase in RPS intermittent generation contributes to this increase in the daily load swing. Additional dispatchable control range will be required from the non-RPS resources to successfully integrate this renewable energy mix.

Meeting the need for the forecast levels of controllable generation can be managed through improved day-ahead planning and procurement of future energy resources. Energy supplies which are unable to cycle during the off-peak periods, or to ramp in accordance with control area operator instructions, would be ill-suited to supply California's future energy needs; whereas, generators which could be readily cycled down and up as needed would better fit into the required energy mix. This suggests that there must be some attention paid to the availability of attributes (such as controllability and ramping capability) of both future generation and contract additions to the utilities' portfolios, as well as to the quantities of each generation attribute that are included in the utility portfolio.

Findings

1. The forecast 2010 maximum daily load swing, as compared to 2004, will increase the requirement for controllable generation by nearly 2,200 MW and is attributed to the following:
   - The increase in forecast load is estimated to increase by nearly 1,100 MW.
   - The increase in renewable generation is estimated to increase by 1,100 MW.

2. The average requirement for daily controllable generation due to load and resource changes is estimated to increase by 1,000 MW.

3. The average change in daily load swings due to RPS integration is estimated to be approximately 400 MW.

4. The changes in controllable generation requirements are not significant but the volatility increases.

5. Some changes in renewables mix, for example, increasing the penetration of solar from current forecast, will reduce the future increase in swings.

Actions and Policy Options

1. The control area operator should establish “attribute requirements” for controllable generation.

2. The control area operator along with the Energy Commission should forecast future needs for control attributes (and that future level becomes the metric for performance monitoring).

3. The load serving entities should be required to provide sufficient generation to meet the attribute requirements of the control area operator. Close coordination is required where multiple load serving entities are located within a single control area.

4. Generation management procedures and communication infrastructure requirements (between the control area operator and generation facility) must be in place if insufficient generation to meet the attribute requirements are not provided.

Minimum Loads

Issue

When total off-peak power production (after reducing controllable generation to minimum levels) exceeds loads, it is referred to as a minimum load problem. High levels of off-peak production (e.g., from base load, existing contracts, hydro runoff/run of the river and intermittent energy resources) pose operating challenges for the control area operator, the transmission operator, and the energy supplier (retail supplier) and may require generation curtailment, reduction in imports, increase in off-peak sales, or increase in off-peak loads (pump storage or retail customer load).

Focus

Minimum load conditions can take on two different characteristics:

1. Total generation may need to be reduced in output and may result in reducing some generation that typically is not curtailed, or that may incur some operational costs to curtail for short periods overnight. This is considered an economic minimum load condition.

2. Total generation may already be reduced to the minimum secure levels of production from the individual generators and any further reduction in total generation will require removal of some generation from operation. This is considered a physical minimum load condition.

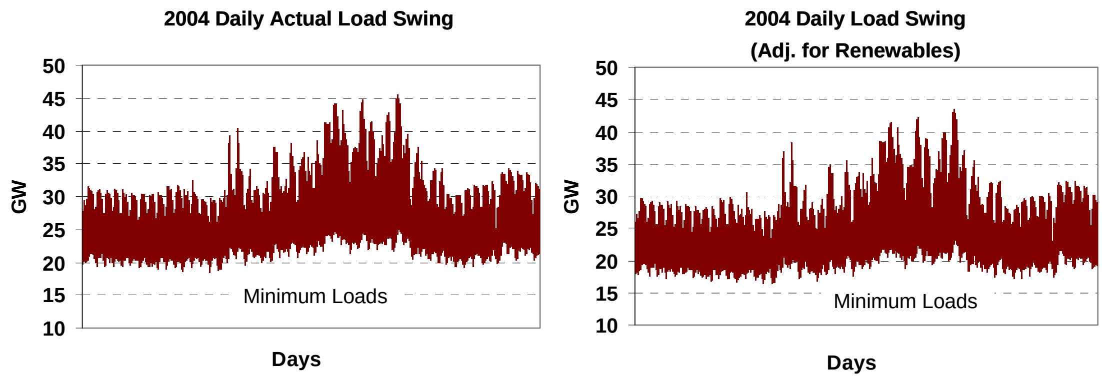
This assessment did not attempt to identify situations described by either 1 or 2 above – instead it identified the impact of the addition of non-dispatchable renewable generation on the total level of present and forecast future minimum load generation.

Methodology

To estimate the impact of the accelerated renewables development on future minimum load conditions, the forecast hourly energy production from the renewable generation was modeled to be non-dispatchable. Deducting this total hourly generation from the 2010 forecast hourly load, a residual load profile was developed which would be served by the remaining non-RPS portfolio. By comparing the present daily and seasonal minimum residual loads with the forecast daily and seasonal minimums, the general direction of the minimums can be determined.

Figure 6 illustrates the impact of the present renewable portfolio on the daily and seasonal minimum loads for the recorded 2004 year. This analysis indicates an average reduction of 2,100 MW in residual minimum load available for non-renewable generation.

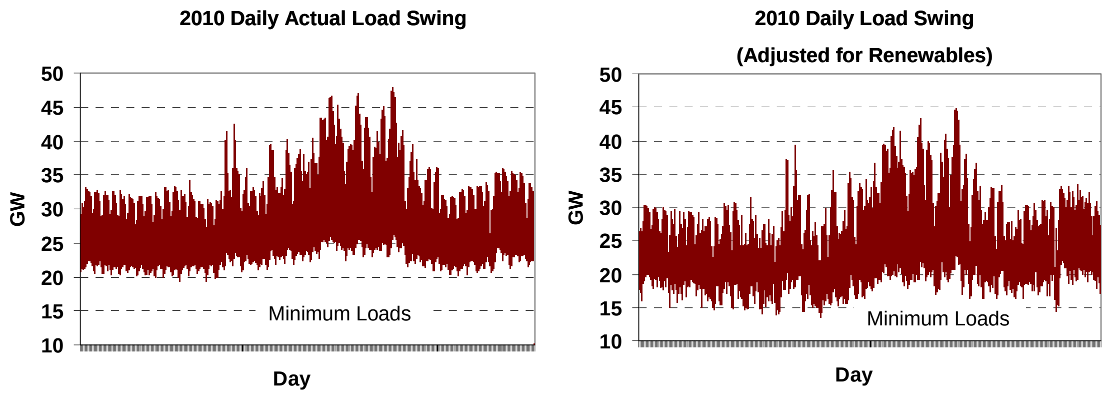
Figure 6
2004 Daily Minimum Loads with Renewable Generation



Daily Minimum Load Statistics	Actual Min Load	Actual Load Minus Renewables	Difference
Average	21.2	19.1	-2.1
Maximum	24.9	23.1	-1.8
Minimum	18.4	16.4	-2.0
Standard Deviation	1.3	1.3	-0.1

A similar analysis for 2010, as shown in Figure 7, reveals that the daily minimum loads are reduced by an average 4,300 MW with the inclusion of the projected RPS generation.

Figure 7
2010 Daily Minimum Loads with Renewable Generation



Daily Minimum Load Statistics	Forecast Min Load	Forecast Min Load Minus Renewables	Difference
Mean	22.3	18.0	-4.3
Maximum	26.2	22.7	-3.4
Minimum	19.4	13.4	-6.0
Standard Deviation	1.4	1.9	0.5

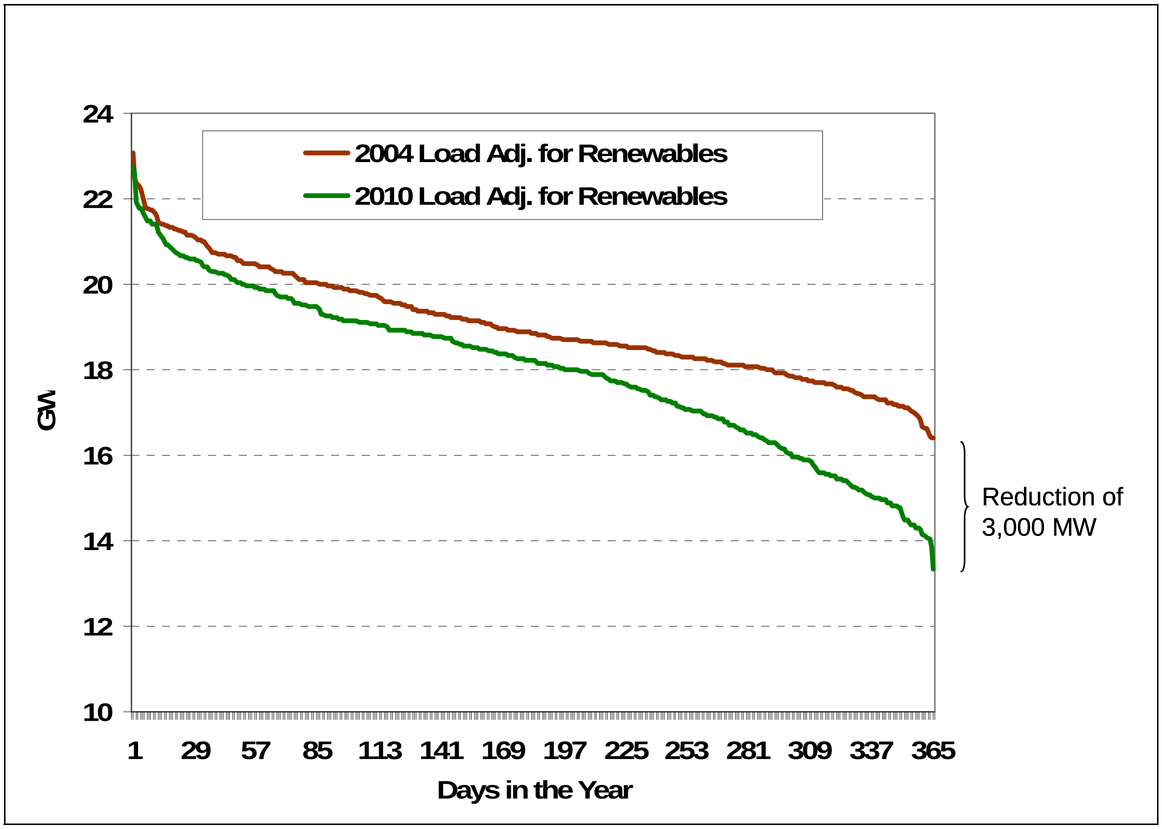
Table 2 below shows the residual minimum load after inclusion of renewable generation in 2010 compared to that in 2004. The reduction in minimum loads is an average of 1,100 MW and 3,000 MW when comparing the absolute minimums.

Table 2
Residual Minimum Loads with Renewables

Residual Minimum Load Adjusted for Renewables (GW)	**2004**	**2010**	**Difference** ('10 – '04)
Average	19.1	18.0	-1.1
Maximum	23.1	22.7	-0.4
Minimum	16.4	13.4	-3.0

Figure 8 shows the results of Figures 6, 7, and Table 2 in a load duration curve. As illustrated, the minimum loads for 2010 are 3,000 MW lower than for 2004.

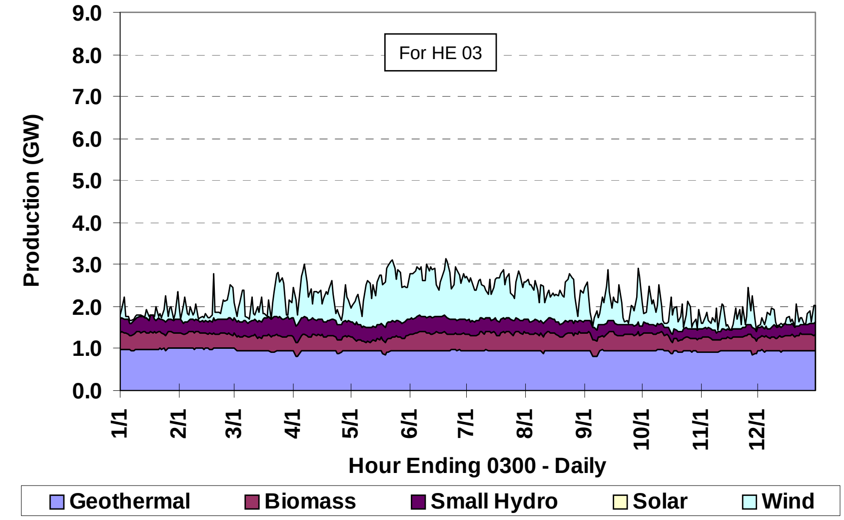
Figure 8
Comparison of Minimum Loads



Analysis
Since the daily minimum loads for 2010 are lower than for 2004 for nearly every day of the year, while the daily maximum loads are the same or higher, there will be a need for greater cycling capability in the controllable generation portfolio than is required to serve the 2004 load. For the most extreme forecast days in 2010, there will be a need to be able to reduce generation output by up to an additional 4,000 MW on nearly a daily basis for nearly two calendar months, which coincide with high run-off and high wind periods.

Figures 9 and 10 respectively illustrate the recorded 2004 and projected 2010 energy production from the RPS portfolio, reflecting the high levels of production in late spring, which coincides with the spring hydro runoff season. The correlation of these two high production events will create significant pressure on the control area operator to manage the generation during the lightly loaded early morning hours.

Figure 9
2004 Actual Daily Renewable Production



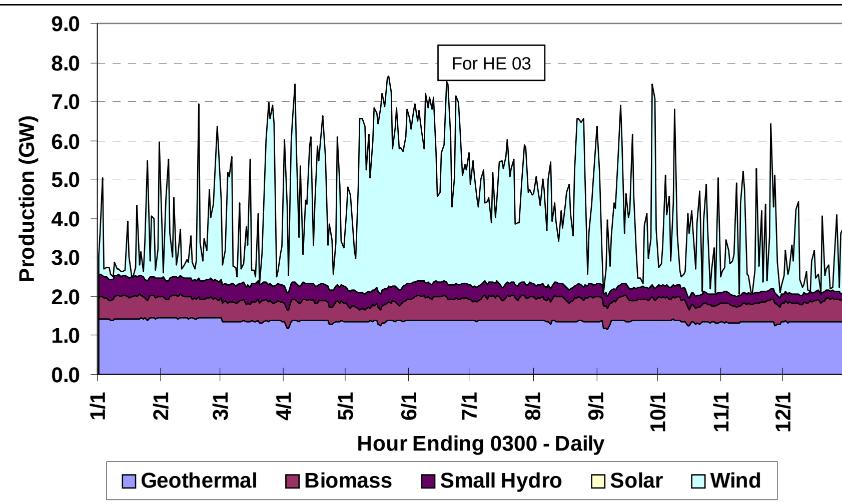
Total Production

- Mean = 2.2
- Max = 3.1
- Min = 1.4
- Std. Dev. = 0.4

- Highest in May and June

- Lowest in fall

Figure 10
2010 Forecast Daily Renewable Production



Total Production

- Mean = 4.2
- Max = 7.6
- Min = 2.0
- Std. Dev. = 1.5

Discussion
To manage the greater range of daily generation swing, and the lower nighttime minimum generation levels estimated for 2010, several factors need to be considered.

1. Operating combined cycle gas turbine (CCGT) plants around-the-clock or base loaded may result in lowest unit production costs but higher system costs when requirements such as the full generation cycling and minimum generation turn-down requirements of the forecast 2010 energy mix are considered.

2. Continuation of energy procurement contracts on a 24-hours per day, 7 days per week basis (24x7), such as the Department of Water Resources – California Energy Resources Scheduling (DWR-CERS) contracts, would further aggravate the minimum load conditions. Replacing these contracts upon expiration with generation that matches load profile will mitigate minimum loads and facilitate new renewables integration.

3. Exporting excess energy through off-system sales is an attractive option but the typical trading partners may be less able to accommodate California's excess off-peak energy as they too may be adding renewables.

4. Enhanced use of existing pumped storage facilities should help to mitigate the minimum load problem (see the discussion on Storage, below).

5. Enabling end-use customers to participate in real-time dispatch and load shifting through price signals or other initiatives for off-peak load building will improve minimum load operations.

6. Finally, there may need to be changes to the energy market to ensure that generation which provides the necessary operational and turn-down flexibility needed by the system operator to effectively manage the grid are adequately compensated. A purely spot energy market price may not be sufficient to value these additional operational attributes on a going-forward basis.

Findings

With development of the additional renewable generation to meet RPS, the daily and seasonal minimum loads will be lower in 2010 than they were in 2004 essentially for all days of the year. To meet these lower loads without jeopardizing grid reliability, the operating performance of controllable generators will have to provide sufficient flexibility (e.g., cycling and turn down capability) to the grid operator. Changes in energy contracting may be required.

Policy Options

1. The control area operator should establish the existing attribute requirements for controllable generation (see Appendix C).

2. The control area operator along with the Energy Commission should forecast future needs for control attributes (and that future level becomes the metric for monitoring planning and performance).

3. The load serving entities should be required to provide sufficient generation to meet the attribute requirements of the control area operator.

4. Determine what impact the following will have on the expected minimum load conditions:

   - DWR-CERS contracts expiring. Over 2,000 MW of state signed “7x24” contracts drop off starting 2010.
   - Qualifying Facilities contracts expiring
   - Shutdown of Mohave Generating Station
   - More flexible contracts with coal suppliers

5. Work with market suppliers to develop more flexible products that match load shapes.

6. Explore opportunities for seasonal exchanges with the Pacific Northwest or other regions of WECC.

7. Develop a state-wide coordinated pump storage strategy.

8. Develop a market such that the appropriate price signals are available to end use customers during periods of minimum load.

9. Generation management procedures and communication infrastructure requirements (between the CAO and generation facility) must be in place if insufficient generation to meet the attribute requirements are not provided.

10. Develop the necessary policies and procedures to clearly identify the priority order of managing resources during minimum load conditions

Reserves and Ramping

Issue
The adequate supply of generation reserves and ramping capability is essential to maintain operating margins for safe and reliable operation. Installed reserve capacity includes both stand-by and operating reserves and can be brought on/off-line at short notice to balance deviations between actual/forecast of generation or load. Reserve calculations are impacted by the methodology used to incorporate capacity in operations and resource planning. For example, should nameplate capacity be used or dependable operating capacity or expected load carrying capability or expected production?

Focus - Reserves

Work has already been conducted by the Energy Commission to estimate the effective capacity value of renewable generation for long term planning purposes.[3] For the purposes of this assessment, the effective capacity values already determined for the California renewables are assumed.

Implicit in the methodology used to determine effective capacity value is the assumption that the planned generation is available to serve load at any time it is not otherwise forced or scheduled to be offline for maintenance. (For intermittent generation, this unavailability exception is broadened to include those time periods when the generation is unable to produce energy due to lack of prime mover energy, such as periods of no sun or wind). Thus, for generation which is otherwise not energy limited, it is expected that the generation will be available to serve load when called upon. During actual operation, the control area operator must balance the reliability need to provide sufficient capacity to cover load variations and contingencies with the cost of keeping reserve generation on-line. With the addition of intermittent generation, such as wind, with its greater variability in output, it will fall to the control area operator to maintain sufficient operating reserve (spinning and non-spinning) to meet WECC and NERC standards.

Purpose of Operating Reserve

Operating reserve is required to assist real-time operations in managing the uncertainty and contingencies related with operating the grid, such as load and resource variations and forced outages of lines and resources. WECC requires adequate operating reserves to cover regulation requirements, non-firm imports, on-demand obligations and largest contingency. Contingency reserve is the greater of (1) loss of the largest generator or transmission line from a single contingency or (2) the sum of 7 percent for load served from thermal and 5 percent for load served from hydro generation.

Knowledge of Operating Reserve

WECC requires that operating reserves shall be calculated such that the amount available which can be fully activated in the next ten minutes will be known at all times.

Managing Operating Reserves in Real-Time

- Hourly regulation requirements will require CAO to continuously adjust the operating reserves (up or down).

- Forecast errors (load and resource) will require CAO to continuously adjust operating reserves (up or down).

- Contingencies (forced outages of lines or generation) will require CAO to replace their operating reserves within 60 minutes.

Discussion

In real-time operating reserve requirements are impacted by the decision on how much of the energy from intermittent resource is counted on as firm capacity. Below are three options to illustrate a methodology in which intermittent energy resources can be incorporated into the daily and hourly energy and capacity planning:

1) Incorporate energy production forecast in the plans based on nameplate ratings;

2) Incorporate the day-ahead forecast hourly quantity of energy in the plan; and

3) Incorporate none of the day-ahead forecast hourly quantity of energy in the plan (i.e., plan based on zero output from the intermittent resource)

Option 1 recognizes full nameplate capacity of all resources in the plan. For example, an intermittent generation facility with 100 MW of installed capacity will be assumed to produce 100 MW every hour. While recognizing full capacity of the generation, it will nearly always overstate the actual energy production and available capacity. Since capacity is overstated, offsetting additional reserves are required in order not to have an adverse reliability impact.

Option 2 relies on expected intermittent resource output in the daily plan. This will result in some variation around the forecast either an excess of energy resources (which means more to sell and possibly some operational impact, but typically little reliability impact), or a deficiency of energy resources (which means more to buy, and occasionally an adverse reliability impact). However, the impact is a lot less than Option 1.

Option 3 values the intermittent resources in the daily plan at zero. Thus any actual energy produced will be in excess of the plan, requiring continuous rebalancing of the plan. This will result in excess energy having to be sold (or not produced), with little reliability impact but some operational impact. The operational impacts results from the need for some dispatchable resource to operate at or near their minimum limits and making them less responsive to the control area's 10 or 15 minute response requirements. This will especially be true during minimum load periods), but there would not be an energy deficiency due to overestimation of intermittent generation (which means no adverse reliability impact). Under this option, the control area will nearly always be carrying excess amounts of unloaded generation, but technically not excessive reserves, since operating reserves is unloaded generation (or generation off line) that can be activated within ten minutes minus (-) the non-firm energy (i.e., intermittent resources).

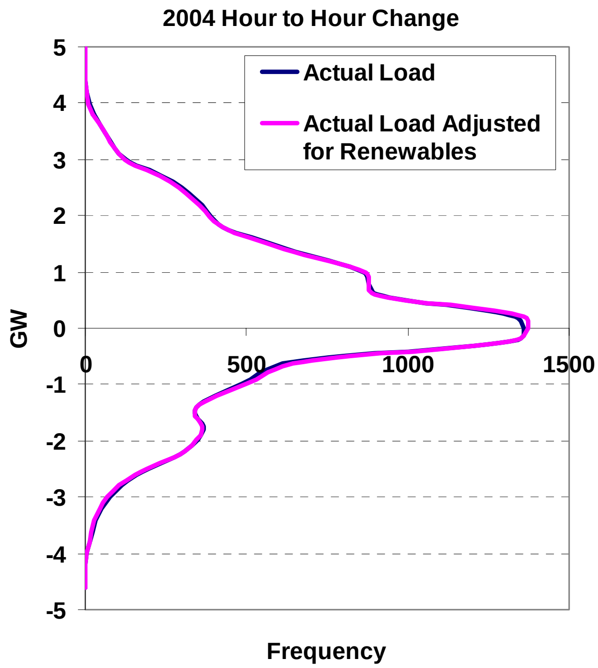
Additionally, operating reserves are defined by the greater of the largest contingency or 7 percent thermal and 5 percent hydro of the load requirement. Assuming the intermittent generation was: 1) counted on at or near its nameplate capacity, 2) the CAO defined the generation as a single contingency (e.g., on a single collector station), and 3) the generation capacity exceeded the reserve requirement based on the percent of load, the reserve requirement would be higher defined by the largest contingency criteria.

There are, of course, many degrees of flexibility between these extremes, such as including some portion, but not all of the hourly forecast intermittent energy. One of the key objectives to successfully integrating RPS resources is to maximize operating efficiency while operating within reliability standards. To achieve that optimum balance point, requires good historical trends, accurate real-time weather data, operating experience and improved forecast techniques. The more we attempt to improve the resource efficiency there will be a greater dependency on the non-RPS resources to provide greater flexibility and to posses the necessary attributes (e.g., quick start, fast ramp capability).

Focus – Ramping

To illustrate the impact of the changes in the hourly ramp, the three-hour ramp, and the six-hour ramping requirements are analyzed. Figure 11 illustrates the change in the hour to hour ramping requirements for recorded 2004. When the variations associated with the renewable generation for 2004 are included, the total ramping requirement (load plus renewable generation change) experienced negligible change. Similar conclusions were drawn for the three-hour and six-hour ramping requirements.

Figure 11
2004 Renewable Production Impact on Hourly Ramps



Actual Load

- Mean = 0.0
- Max = 3.9
- Min = -4.3
- Std. Dev. = 1.3

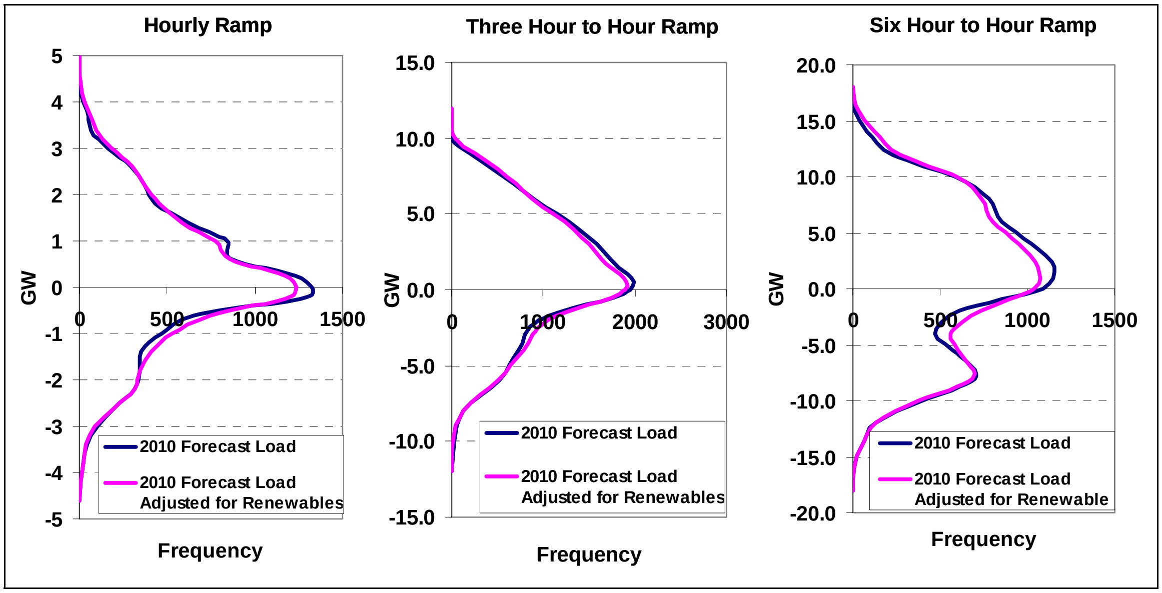
Actual Load (Adj. for Renewables)

- Mean = 0.0
- Max = 3.9
- Min = -4.3
- Std. Dev. = 1.3

Renewables negligibly changed hourly ramps

Under a similar analysis focusing on 2010, the projected hourly, three-hour and six-hour ramping requirements are presented in Figure 12.

Figure 12
2010 Renewable Production Impact on Hourly, Three-Hour and Six-Hour Ramps



As shown Table 3, the maximum upward ramping requirement increases by 300 MW, 600 MW, and 1,300 MW for the three ramp intervals, while the downward ramping requirement increased in the first two ramp intervals by 100 MW and 500 MW respectively. These changes in ramping requirements are in addition to the ramping requirements inherent in the load pattern. Figure 12 and Table 3 illustrate that with the addition of renewable generation, there will be a greater need for upward ramping capability, and a smaller need for increased downward ramping capability in the generation portfolio of 2010.

Table 3
2010 Renewable Production Impact on Hourly, Three-Hour, and Six-Hour Ramps

(GW)	Hourly Load Change	Hourly Load Change (Adjusted for Renewables)	Difference	3-Hr Load Change	3-Hr Load Change (Adjusted for Renewables)	Difference	6-Hr Load Change	6-Hr Load Change (Adjusted for Renewables)	Difference
Max.	4.1	4.4	0.3	8.6	9.2	0.6	14.9	16.2	1.3
Min.	-4.6	-4.7	-0.1	-11.7	-12.2	-0.5	-17.4	-17.1	0.3
Std. Dev.	1.4	1.3	0.0	3.7	3.8	0.1	6.3	6.4	0.1

Because thermal generation typically ramps at a rate of approximately 1 percent of capacity per minute (except during emergency conditions) in order to achieve a ramp of 500 MW in a single hour, approximately 830 MW of unloaded generation capacity is required at the beginning of the ramping hour (830 MW x 1 percent x 60 minutes = 500 MW). This requirement for unloaded generation is in addition to the control area operator's requirement for spinning reserve and operating reserve, because this unloaded generation will be progressively loaded up during the hour to meet the ramping requirement. (Note that while the assessment is based on hourly data, it is possible that there are even faster ramping requirements within the hour due to changes in load or generation.)

As these figures illustrate, the overall ramping requirements are greater with renewable generation. This increase should be manageable if the mix of future non-RPS generation has the ability to ramp up and down to follow dispatch instructions. The need to dispatch renewables may be infrequent but the ability to do so will provide CAO with needed operating flexibility for reliability management. It will be important for both the control area operator and the load serving entities to carefully assess the need for controllability in procured generating resources. (See Appendix C for a list of generation attributes).

Policy Options

1. The control area operator will need to carefully assess the existing needs for controllability and ramping capability. (See Appendix C.)

2. The load serving entities should be required to provide a resource mix which will meet the control attributes established by the control area operator.

3. Reserves
   - Immediately start monitoring and tracking forecast and actual performance for all intermittent resources by:
     - Consistent standardized method and metric
     - Developer, region, LSE and CAO
     - Day-ahead, 12-hours ahead, 6-hours ahead and 3-hours ahead

   - Deploy best available metering to support better forecasts.

   - Perform benchmarking study to identify best-in-class for forecast models, processes and techniques.

   - Assure that the portion of the LSE and CAO resource portfolio used to provide operating reserves has the necessary attributes (e.g., quick start, fast ramp, cycle) to enhance efficiency while ensuring reliable operations.

   - Monitor and track compliance with WECC reserve standard

Load and Generation Forecast Variability

Issue
Accurately forecasting both the day-ahead and hour-ahead load and generation is important in maintaining reliable operation and achieving economic efficiency.

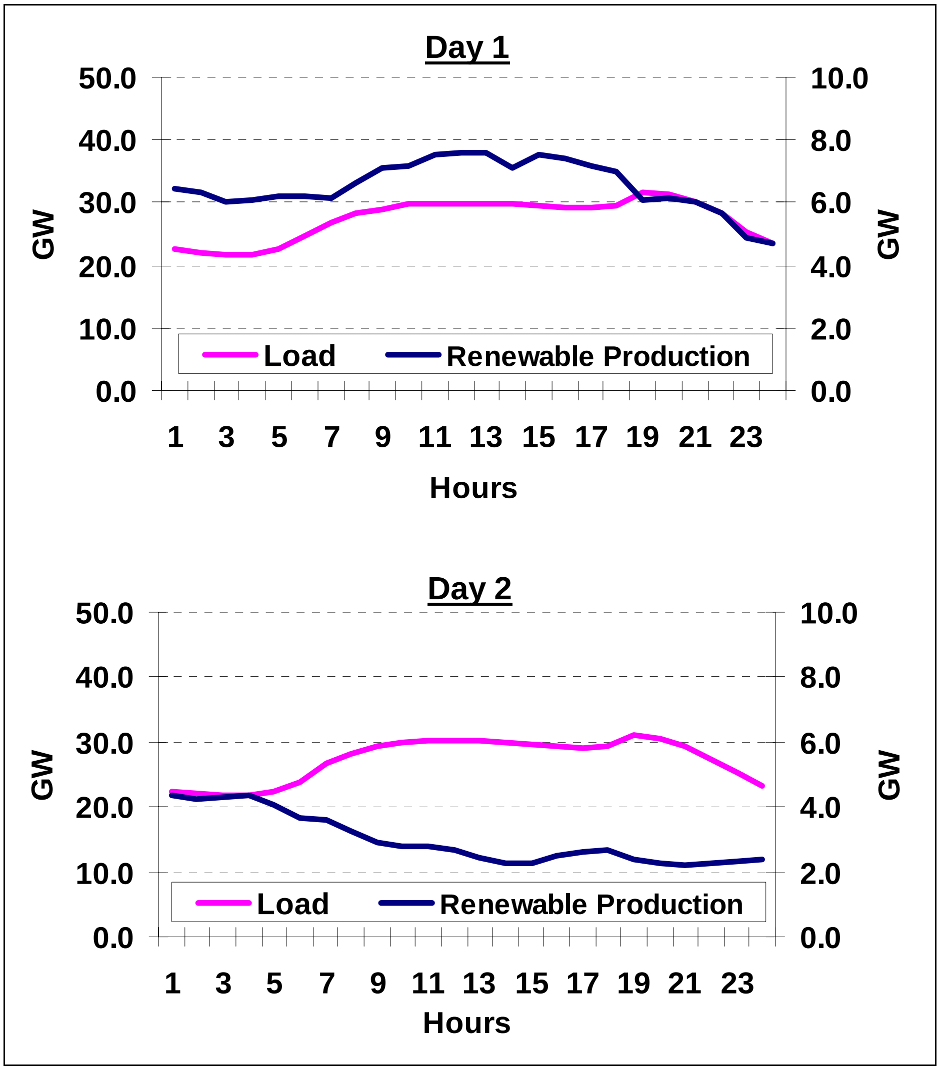
Focus
The importance of accurate forecasting of both load and generation for operations planning is discussed.

A common way for utilities and CAOs to forecast renewable generation is to assume tomorrow's generation will be the same as today's latest recorded information. This is known as the persistence model approach and is currently utilized by CAOs as alternative forecasting methodologies have failed to improve forecast error.

Applying the persistence model to the forecast CA ISO renewable generation in 2010,[4] the difference in renewable generation at the time of daily system peak demand can be examined from one day to the next. The difference in daily production is quantified with perfect foresight given the 2010 forecast hourly renewable generation.

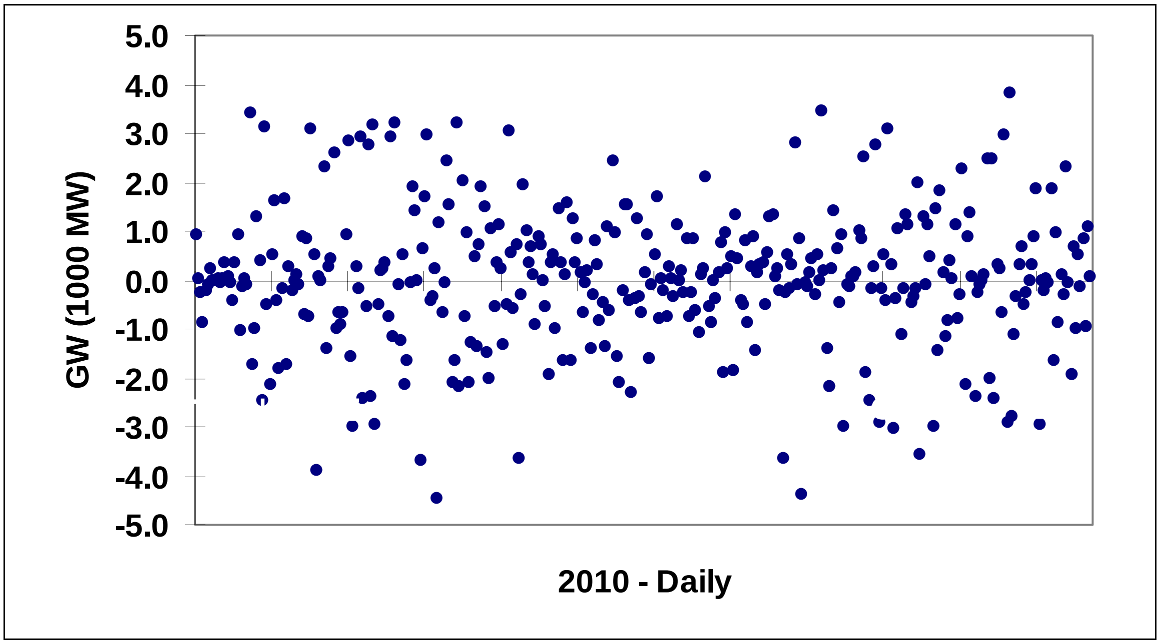
This is illustrated by examining the change in renewable production between two consecutive dates in April 2010, as shown in Figures 13. The forecast wind production on April 2 at time of peak is 6.1 GW. The forecast wind production at time of peak for the next day April 3 is 2.4 GW. However, if a persistence model is used, the operating plan would have assumed a production of 6.1 GW on April 3 versus the actual production of 2.4 GW, resulting in a forecast error of 3.7 GW

Figure 13
Forecast Load and Renewable Production
(Two Consecutive Days – April 2010)



A chronological x-y plot of the 2010 daily change in CA ISO renewable production, at time of the system peak load, is provided in Figure 14. Daily change in total renewable production ranges from a minimum of minus 4.5 GW to a maximum of 3.5 GW with a standard deviation of 1.4 GW.

Figure 14
2010 Daily Change in Renewable Production at Peak



This expected variance in renewable energy production from one day to the next will have significant operational implications for the CAO. It makes improved forecasting techniques over the persistence model imperative so that generation commitment and dispatch decisions can be made in a timely manner to balance generation and load in real time.

The required attributes of replacement controllable generation, including start-up time and ramping capability, will depend on both the lead time and accuracy of production forecasting models.

Methodology to Reduce Forecast Error
State-of-the art wind forecasting techniques and monitoring systems need to be investigated and employed to insure successful integration of the accelerated RPS generation.

The accuracy of the intermittent energy forecast is critically important to the effectiveness of incorporating intermittent energy into the grid operation, with a perfectly accurate forecast being the goal. Furthermore, because forecasts typically improve in accuracy with reduced time horizons between forecast and actual, scheduling protocol changes which can reduce the time lag between preparing the forecast and energy plans, and the actual operation, are beneficial.

Finally, it must be noted that intermittent resources are neither the sole source of unpredictability, nor are they necessarily the largest source of hourly uncertainty. Load forecasting is imprecise at best, with error rates up to several percent on extreme load days. Furthermore, generation and transmission forced outages can easily remove several hundred MWs of capability from the grid, requiring significant resource rebalancing. So, while intermittent resources introduce some uncertainty in the daily plan, they are neither the sole, nor necessarily the most significant causes of that uncertainty. It is the role of the grid operator to manage the grid in the face of that uncertainty, at the lowest practicable cost.

Much work has been done in recent years to improve the tools used to forecast wind energy, and to improve the sources of raw data for such forecasting tools (such as installation of meteorological monitoring stations in the right locations. With these improvements have come more accurate forecasts of hourly wind energy. To the extent that improvements can be made to both the weather monitoring capabilities at California's wind sites, and to the forecasting models which use that data, California will facilitate integration of intermittent wind generating resources into its electric grid, with fewer operational and reliability impacts.

With improved wind forecasts, California can more confidently incorporate the hourly forecasts of wind production into its daily and hourly resource planning, with the expectation that any real-time adjustments will be both small, and readily manageable.

Findings

California's goal of expanding the role of renewable generation resources to provide 20 percent of the state's energy by 2010, and which includes a greatly expanded role for wind generation, can most effectively be supported by a continued focus on improving the monitoring and modeling of renewable energy and improving wind forecasting tools and techniques, as well as critically evaluating scheduling protocol changes which would shorten the lead time between forecasting, scheduling, and actual operation.

Actions and Policy Options

1. Implement state-of-the-art wind production forecasting.
2. Continue efforts to improve wind monitoring and data gathering.
3. Evaluate changes in CA ISO protocols to allow later forecasting of intermittent energy for daily and hourly planning.

The reliability and operational issues 5-9 were not analyzed by the study team for the following reasons:

Storage

Issue
Storage has been identified as one means of mitigating minimum load impacts.

Focus
The state presently has over 4,000 MW of pump storage capability. This capability is under the control of several different organizations and they are located in two separate control areas, the CA ISO and the Los Angeles Department of Water and Power. The portion that is within the CA ISO control area is controlled by three entities, SCE, Pacific Gas and Electric (PG&E) and California Department of Water Resources, who may require the use of these facilities for their own resource needs or in the case of SCE and PG&E to turn over dispatch to the CA ISO.

Furthermore, during certain times of the year, some of these pumped storage facilities may have limited or no pumping capability due to both water flow-through requirements, such as during the spring runoff season, and due to low fore bay water levels which prevent use in the pumping mode.

Analysis
Two questions were considered with regard to storage:

1. Should storage be required as an adjunct to further development of renewable resources?
2. Is the present storage capability being used effectively?

With regard to the first question, it was the consensus of the stakeholders that expansion of the state's energy storage capability should be considered separately from the expansion of renewable generation. There are many options for managing the combined energy production from both the RPS and non-RPS portfolios, of which expanding or enhancing the use of storage is but one option. Thus, linking storage to expanded renewables is not warranted. Moreover, storage, if it is needed, can be economically justified on its own merits.

Second, the scope of this assessment limited our ability to examine the extent to which the combined pumped storage capability of the state was now being used to enhance operational flexibility. However, due to the diversity of operators and their respective grid interests, it is likely that a more holistic strategy for operation of all the pumped storage facilities in the state would yield a more efficient overall operation.

Finally, there exist contractual options to achieve additional pumped storage-like capability through day-night and seasonal energy exchanges with other regions of the west. These options have been used in the past and may still be available if conditions warrant their use again in the future.

Findings
Storage is but one option in a large portfolio of generation control options available to the state. Before any substantial effort is expended in exploring the development of additional storage alternatives, the control area operators should identify the generation attributes needed to effectively manage the grid in 2010, and the quantities required of each of those identified attributes. The load serving entities should then be required, with the active participation of the Energy Commission, the CPUC and stakeholders, to identify resource portfolios that will meet the control area operator's needs for capacity, energy, and the other generation attributes identified. Additional storage, if it is required, would then be an option to provide some of the generation attributes.

Policy Option
Develop a state-wide coordinated pump storage strategy.

Frequency and Voltage Requirements

Issue
In the case of a low voltage ride-through (LVRT), WECC has made an assessment and determined the need for a LVRT standard. On March 3-4, 2005, the WECC Planning Coordination Committee (PCC) voted on and approved the LVRT performance standard, as modified and at the April 6-8, 2005 meeting; WECC Board also voted on and approved a LVRT performance standard, as modified by PCC. The standard is scheduled to be implemented in March of 2006. Also, FERC is currently going through a due process to establish a LVRT standard at a national level. AWEA has taken a leadership role in sponsoring an LVRT standard at FERC. The LVRT standard will impact system design and operations, for example the size of a substation, number of collector stations to interconnect intermittent generation, or fault current propagation. This needs to be evaluated by utilities and assess system specific impacts and guidelines to plan a reliable system conforming to adopted standards.

As a result of this new WECC LVRT standard being implemented, each transmission owner and control area operator will now have to assess how the standard will impact their planned grid interconnections and expansion.

Policy Option
The frequency response of generating resources in WECC has been deteriorating over the last two decades for various reasons and is not uniquely related to the introduction of renewable resources onto the system. The reliability authorities (e.g., transmission owner, control area operator and reliability regions) collectively, through an open process forum, need to perform the necessary evaluations and assessment to accurately determine those generation attributes that relate to frequency, as well as the minimum acceptable performance level of the attribute,

that are essential to grid reliability. Based on their findings, a due process could be initiated for the establishment of a frequency response and/or ride-through standard.

Resource Deliverability

Issue

Currently, utilities and generators perform and comply with interconnection standards and requirements to connect generation. Interconnection standards, however, do not address deliverability, which is the ability to move power freely across the interconnected grid.

For the investor-owned utilities which are under the CPUC jurisdiction, there is an established process to evaluate deliverability under the resource procurement process. The deliverability evaluation process only requires an assessment at the time of the annual peak demand. That process may be adequate to insure deliverability for some of the RPS resources that are either base loaded or whose energy production correlate well with the load demand, but for some intermittent resources, such as wind, the peak production periods may not be during the summer months or the on peak hours of the day. As a result, when simulation and power flow studies are performed, at time of peak, they will reflect limited production from some intermittent resources and therefore, may miss potential problems. It is only when the resources become operational and attempt to deliver maximum energy production onto the grid, during non-studied hours, that the problems start showing up. At that time, the only recourse for the system operator is to implement some form of generation curtailment or congestion management protocol resulting in stranded generation. The net impact of this inadequate deliverability assessment is that the state, and ultimately the consumer may not realize the full benefit from the RPS resources.

Policy Options

1. The reliability authorities (e.g., transmission owner and control area operator) collectively need to perform a more comprehensive state-wide deliverability evaluation to ensure the grid is adequately designed for resource deliverability during the non-peak time periods (e.g., spring time and evenings).

2. Utilities need to study their systems to assure deliverability of renewable generation over a range of operating conditions. This may result in requirements for additional investments beyond the first point of interconnections (capacitors, transformers, and debottlenecking projects) which need supportive regulatory policy to address cost recovery.

Transmission Import Capability

Issue

The frequency response of generating resources in WECC has been deteriorating over the last two decades and reduced inertia and variability in generating performance in this area could negatively impact existing transmission path ratings into California and throughout WECC. This reduced performance is a result of 1) many generating resources throughout the WECC operating at base load (i.e., coal), leaving limited upward capability, 2) nuclear resources, under regulatory mandate, operating with their governors blocked (non-responsive), 3) modified combustion control systems on conventional thermal resources and 4) the design characteristics of the new combined cycle plants.

With the above in mind, under the sponsorship of Governors Richardson and Schwarzenegger and the Western Governors' commitment to a viable economy and a clean and healthy environment in the West they have agreed to collaborate in the exploration of opportunities to develop a clean, secure, and diversified energy system for the West and to capitalize on the region's immense energy resources. Western Governors will examine the feasibility of achieving a goal to develop 30,000 MW of clean energy in the West by 2015, of which California, under the accelerated RPS, is expected to add almost 7,000 MW of RPS resources by 2010. The significant portion of those resources may provide a limited or no contribution to the necessary frequency response required to effectively manage an integrated grid.

There are three major items that will affect the transfer capability of a transmission path: (1) the thermal capability of installed facilities, (2) the voltage support between source and sink and (3) the dynamic performance of generation resources during a likely contingency event. A significant change in the operational resource mix, at times, could potentially have a negative impact on the transfer capability of some transmission paths. The impact, if any, may not be noticed during peak periods when there is approximately 150,000 MW of connected generation, but an issue could arise during the many non-peak hours of the year.

This is not an issue caused by RPS resources, but the impact of a significant change in the WECC resource mix, as a result of the above commitment, needs to be evaluated, especially during non-peak hours and seasons.

Policy Option

The reliability authorities (e.g., WECC members, transmission owner and control area operators) collectively need to perform a comprehensive region-wide peak and non-peak evaluation of the grid's performance and potential impacts on transfer capability, as a result of a changing resource mix. This will assist California utilities and others in WECC better understand what, if anything, they may need to do to maintain existing transmission path ratings.

Planning and Modeling

Issue
Lack of detailed modeling data to support studies and off-peak study cases to analyze transmission system loadings

It has been the practice of WECC, since 1996, that if you have not studied a condition that you will not operate in such a condition. This practice has worked well for WECC and the reliability of the region. The challenge of the future is do we have the necessary data, information, tools and processes to effectively study the expected operation of the interconnected grid. The following are some of the concerns of those organizations responsible for performing both the planning and operational studies:

- Most transmission planning is done for peak load day conditions, not peak power transfer conditions

- Need to develop off-peak and shoulder peak WECC study cases in order to study transmission loading patterns

- The planning models don't adequately capture the performance of the wind generators

- Lack of detailed modeling data for some intermittent resources to support studies, such as dynamic voltage and frequency performance

- There is an absence of intermittent resource production data available to allow analysis

- There is an absence of meteorological data to support real time wind forecasting

- Lack good forecasts of wind production by time of day to build into power flow studies

So, if we continue to perform local and regional grid studies with the above concerns will we unintentionally find ourselves operating in unstudied conditions and potentially suffer the consequences?

Policy Options
1. A WECC member from a California entity, at the executive level, should be requested to sponsor an initiative at the WECC to address and correct the following concerns:
   - Modeling tools
   - Operational and planning study procedures
   - Development of non-traditional base cases

2. A representative from the wind industry, such as AWEA, should be requested to work with wind developers to assure all necessary and available data required to study the grid performance is provided to those reliability authorities who have responsibility to perform both local and regional studies.
3. The state should deploy or cause to be deployed the necessary monitoring devices and infrastructure to acquire the necessary meteorological data.

Development of Solution Sets and Policy Options for Mitigating Reliability and Operational Issues

The study team researched solution options to address the issues to integrate renewables without adverse impact on reliability or operations. A list of solution options and actions were developed, including the relevance to each issue, and is provided in Table 4 below. For each solution a matrix was developed identifying the proposed action, the likely owner(s), where research is required, and the suggested metric to be used. Solution options A through I are described below.

Table 4
Summary of Suggested Solutions

ISSUES IMPACTED

	Issue Solution Option & Action Required	Load Following	Minimum Loads	Storage	Reserves and Ramping	Load and Generation Forecast Variability	Frequency and Voltage Requirements	Resource Deliverability	Transmission Import Capability	Planning and Modeling
A	**Establish requirements for controllable generation**	x	x	x	x					
B	**Enable load to participate in real time dispatch**	x	x	x		x				
C	**Renegotiate existing contracts for additional dispatchability and minimum load turndown (i.e. DWR**	x	x	x						
D	**Modify CAISO AGC algorithm to make effective use of controllable hydro generation and controllable loads**	x	x	x	x	x			x	
E	**Modify WECC and CAISO interchange scheduling protocols, policies and procedures to enhance the used of renewable resources**	x			x	x	x			x
F	**Ensure adequate generator performance standards are in place with clarity of implementation to ensure system performance**				x	x				
G	**Actively manage generation output which exceeds planned levels, or when total generation exceeds load (e.g. during minimum loads)**	x	x		x	x				
H	**Improve transmission studies**							x	x	x
I	**Improve modeling of renewable generation**							x		x

Solution A - Establish Requirements for Controllable Generation

Establish requirements for controllable generation: While there has been a lot of discussion on the need for controllable generation, there are no metrics or criteria that define how much is needed. Defining requirements for controllable generation -- magnitude, duration, timing by season and day -- will assist the generation stakeholders and market participants to take these requirements into account in their business models. Adequate quantification and tracking of controllable generation requirements will address several of the issues discussed, e.g., load following, minimum loads, reserves and storage. The CA ISO/CAO should take the lead in defining requirements and CEC research support is recommended to define metrics, monitor and track performance against requirements as well as trends.

Actions Required	Owner	Research	Metric
Establish attributes requirements for current controllable generation	CAO		
Forecast future need for control attributes	CAO/CEC	Yes	CAO determines quantities of various attributes required, those levels become the measurement metrics
Monitor and track requirements needs	CAO		
Acquire sufficient generation with necessary attributes to meet AGC and load following requirements in procurement process	LSE		

Solution B - Enable Load to Participate in Real-Time Dispatch

Enable load to participate in real time dispatch: There is minimal load participation in real time dispatch. Experts have opined that small amounts of load participation -- of the order of 5 to 10 percent -- can go a long way in improving market efficiency, mitigating market power, and reducing the control requirements for generation. To facilitate load participation, there are several steps involved -- transparent pricing that is the responsibility of the CA ISO/CAO, infrastructure to enable load participation which will require regulatory support as well as actions by load serving entities (LSEs), and a plan based on research and analysis to establish targets and timetable for load participation and subsequent tracking. This is not unlike what has been done with renewables through establishment of RPS.

Actions Required	Owner	Research	Metric
Provide energy settlement price for real time attributes	CAO		
Standards - Monitor, publish recorded, and forecast future requirements	CAO/CEC	Yes	
Infrastructure - Enable load participation in real time dispatch (Automatic Load Dispatch)	LSEs, CAO, Load Customer, CEC	Yes	Percent (%) of attribute requirements provided by load

Solution C - Renegotiate Existing Contracts for Additional Dispatchability and Minimum Load Turndown

Renegotiate Existing Contracts for Additional Dispatchability and Minimum Load Turndown: Many of the existing contracts hamper the ability to manage real time operation even though the underlying resources being used to meet contract needs have operational flexibility that could be utilized. This will require contract renegotiations by LSEs and CDWR-CERS.[5]

Actions Required	Owner	Research	Metric
LSEs responsible for providing dispatch flexibility renegotiate as required	LSE and CDWR-CERS		Percent (%) of achievable attributes from existing contracts
Regulatory approval of renegotiated contracts to meet CA ISO control area requirements (regulatory review consistent with system needs)	CA ISO (system needs assessment), CPUC Approval		

Solution D – Modify CA ISO AGC Algorithm

Currently, there are some very responsive hydro resources that are not available to the CAO for real-time control. This is due to the existing AGC control logic not effectively complying with the submitted energy schedules and causing water schedule violations. Modify and enhance the AGC algorithms to correct this deficiency thereby providing a low cost solution of capturing additional regulation and load following capability.

Actions Required	Owner	Research	Metric
Specify hydro resource and controllable load availability	LSE		
Modify CA ISO AGC algorithm to effectively use controllable hydro and load to supply AGC and meet hourly energy scheduling targets	CA ISO		Percent (%) of AGC being provided by hydro and MW of load providing ALC
Explore options to enhance use of load for ALC (Automatic Load Control)	CA ISO/CEC	Yes	
Explore options to enhance availability of hydro for AGC usage	LSE/CEC	Yes	

Solution E – Modify WECC and CA ISO Interchange Scheduling Protocols, Policies and Procedures to Enhance the Use of Renewable Resources

Modify WECC and CA ISO Interchange Scheduling Protocols, Policies and Procedures to Enhance the Used of Renewable Resources: The current interchange scheduling protocols and timetable (20 minute ramps, 21/2 hour cutoff for schedule updates etc) were designed in an era when most of the generation was “controllable." With the transition to a market system and increasing contribution of intermittent resources in CA and throughout the WECC, these protocols and guidelines need to be updated. This will involve WECC operating committees working with CAOs and developing metrics and a system for monitoring progress. Protocols that need to be addressed include, for example, ability to update next 2 to 4 hour production forecast on a more frequent basis without penalties.

Actions Required	Owner	Research	Metric
Modify energy scheduling protocol to allow longer ramping times (e.g., 40 minutes rather than 20 minutes)	WECC		Compliance with NERC CPS and percent (%) reduction in regulation requirements
Review of operating reserve standard, greater amounts or intermittent resources in daily generation plan	WECC		
Modify protocols to allow full use of dynamic scheduling of resources between control areas	CAO		
Assess the potential and complexity of modifying CA ISO scheduling protocols to reduce lead times for hour ahead and day ahead scheduling	CA ISO		
Modify market rules to allow for more frequent scheduling updates for intermittent resources	CA ISO/Market Participant		
Investigate best practices in wind energy forecasting, and implement in California for daily/hourly production planning	CAO/CEC	Yes	Compliance with NERC CPS and percent (%) reduction in regulation requirements
Evaluate the normal wind production forecasting error, to assess whether additional operating reserves are needed to backstop wind in the hourly plan	CAO/CEC	Yes	
Establish system to track wind production forecast accuracy	CAO		

Solution F – Ensure Adequate Generator Performance Standards are in Place with Clarity of Implementation to Ensure System Performance

Actions Required	Owner	Research	Metric
Monitor and track the CAOs frequency response performance during system disturbances	CAO/WECC surveys		Metric, as established in WECC survey
Monitor performance to WECC generator voltage performance standard	CAO/WECC via RMS		Compliance with new standard, effective 2006
Determine if there is a need for a governor frequency response and ride-through standard	CAO/WECC		

Solution G – Actively Manage Generation Output which Exceeds Planned Levels, or When Total Generation Exceeds Load

Research in methodologies for generation management and determine if their application is appropriate for California. Germany has implemented methodologies whereby a portfolio of generators can be "controlled" to limit output in the event of over generation that threatens reliability.

Actions Required	Owner	Research	Metric
For current and forecast years, identify those periods when generation would exceed hourly loads (minimum loads)	CAO/CEC	Yes	Minimum load hours per year and MWh/hr
Identify capability of reducing power output from generating resources, such as wind, coal, nuclear, gas, and hydro during minimum load periods	LSEs		
Establish monitoring systems to track performance of LSEs and CAO in managing generation during minimum load periods	LSE and CA ISO		
Establish criteria to economically and efficiently manage generation during minimum load periods	CA ISO and CPUC		
Assess impact of geographic diversity to mitigate wind generation feathering impacts on system operation (sudden loss of large amounts of wind generation)	CEC	Yes	Minimum load hours per year and MWh/hr
Assess resource development	CEC annual assessment		

(including resource type, new designs, and geographic diversity) impacts on system development			
Develop a state-wide strategy to maximize the efficient use of the existing pumped storage facilities	CEC	Yes	
Determine the need for additional storage facilities	CEC	Yes	

Solution H – Improve Transmission Studies

Historically, studies focus on assuring reliability during peak load conditions. With the changing resource mix, it is important to expand the focus of transmission studies and for utilities to identify and fix vulnerabilities that may be present during non-peak system conditions. Utility actions may involve additional investments on the transmission system for local voltage support, deliverability, congestion management, de-bottlenecking and reliability. This will require a coordinated effort between utilities, CAO and WECC as well as support of regulators to make the necessary investments for strengthening the grid.

Actions Required	Owner	Research	Metric
Develop off-peak and shoulder peak WECC study cases	CA ISO request WECC PCC		
Investigate impacts on transfer capability of changing the resource portfolio toward renewables	CA ISO request WECC PCC		
Investigate new tools/solutions to increase interregional transfer capability	CEC or WECC	Yes	
Investigate alternative	CEC/CPUC and CA ISO	Yes	

projects/proposals to expand grid			
Perform routine transmission system loading vulnerability assessments	LSE/CAO		

Solution I – Improve Modeling of Renewables

There is a need to have accurate, data and information related to renewable resources that is readily available to those entities required to perform the necessary grid reliability studies. Included is this need, is the deployment of the necessary monitoring devices and necessary infrastructure.

Actions Required	Owner	Research	Metric
Assure all necessary data and information required for simulation and power flow studies is available	AWEA		
Deployment of the necessary monitoring devices and infrastructure to acquire meteorological data	CEC	Yes	Actual deployment vs. required deployment

APPENDIX A
February 3, 2005, Workshop – Public Comments

(Presented in Chronological Order)

February 14, 2005

California Energy Commission
Dockets Office
Attn: Dockets No. 04-IEP-1F
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

On Thursday, February 3, 2005, the California Energy Commission (CEC) held a Committee Workshop on Transmission – Renewable Integration Issues, Docket 04-IEP-01F. Prior to the stakeholder workshop the Consortium for Electric Reliability Technology Solutions (CERTS) had provided the CEC staff with background material related to an "Assessment of Reliability and Operational Issues for Integration of Renewable Generation." The background material was posted on the CEC web site on January 31, 2005. In addition, CERTS team made a presentation at the workshop on the same subject and hard copies of the presentation were available to all stakeholders in attendance.

CERTS "Assessment of Reliability and Operational Issues for Integration of Renewable Generation" is a work in progress, with a final report due in June 2005. The purpose of the scheduled workshop was to present the research findings to date in an open forum with all stakeholders.

The planned outcomes from the workshop were:

- Validate list of issues identified for the project.
- Identify if there are any gaps in the list of issues.
- Obtain stakeholder feedback on description of issues and any suggested modifications.
- Determine if the project is headed in the right direction and is adequately focused.

The CERTS team objective is to present a factual review of industry experiences and concerns, and identify the reliability and operational issues that would have to be dealt with as California integrates renewable generation to meet the Renewables Portfolio Standard (RPS).

During the Workshop on Feb. 3, during the roundtable following the presentation, the factual basis for two aspects of the materials developed by CERTS, namely E.ON Netz experience and Voltage, were challenged as being misrepresentations. The purpose of this note is to provide specific references and documentation for the sources relied on by the team in developing the materials for the workshop.

Issue 1. The description of aspects of the E.ON Netz experience
Figure #1 is a copy of the slide the CERTS representative presented at the stakeholder workshop that pertained to recent European experience integrating wind into system operations, including that of E.ON Netz:

E.ON Netz and Eltra Operating Issues for Integration of Wind

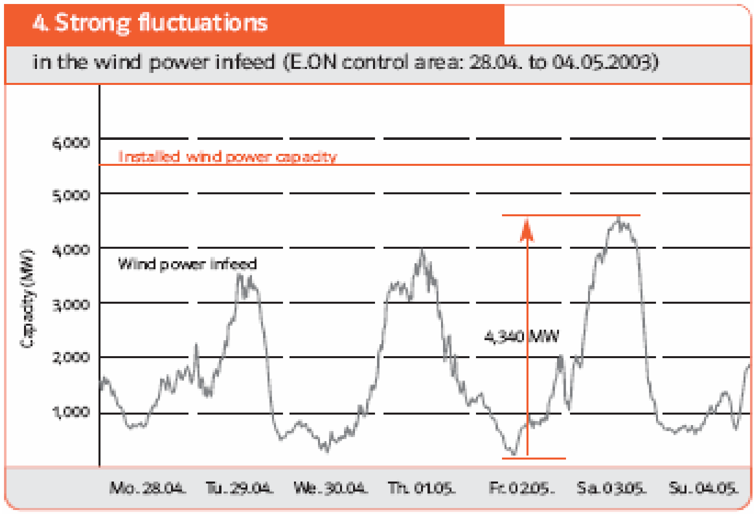
- Forecast Variability
  - Near-term forecast errors of 50 to 60%
- Production Variability (E.ON Netz)
  - Contribution to daily peak load ranged from 0.1 to 32%
- Ramping (E.ON Netz)
  - 6-hour production variability of 60 to 70% of installed capacity
  - Daily production variability of 4,300 MW
- Shadow Reserves – carry reserves for up to 80% of installed wind generation
- No grid voltage support during faults
- Wind plants disconnect during grid faults – E.ON Netz experienced 60% of wind generation loss due to voltage dip in one region
- Methodologies to address issues – generation management, grid code, high reserves, interconnection support

Electric Power Group CERTS 2/3/04 Page 9

Figure # 1 – CERTS Presentation Slide #9

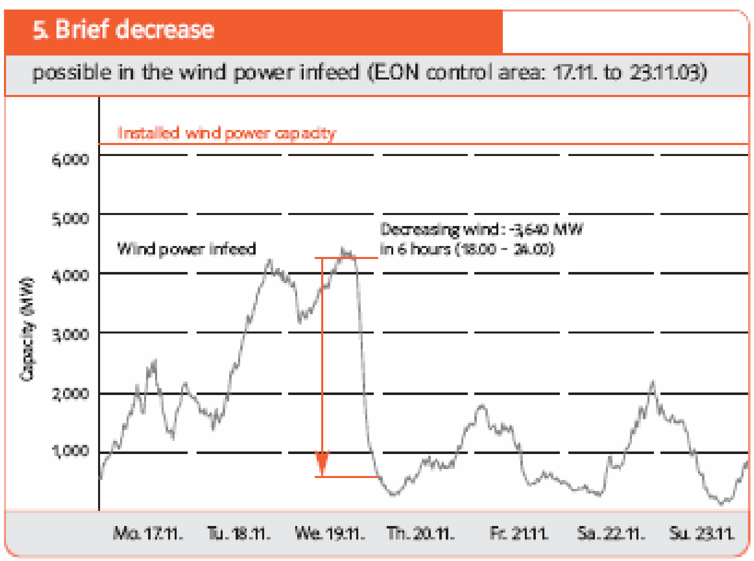
These conclusions were reached from the E.ON Netz report entitled, "Wind Report 2004" (http://www.eon-netz.com/frameset_reloader_homepage.phtml?top=Ressources/frame_head_eng.jsp&bottom=frameset_english/energy_eng/ene_windenergy_eng/ene_windenergy_eng.jsp). Specifically the following material excerpted directly from the report formed the basis of the slide:

Page 6 – "FIGURE 4 shows an example of the wind power infeed pattern in the E.ON territory during a week with strong winds. The difference between minimum and maximum infeed in this example was over 4,300 MW – equivalent to the capacity of six to eight large coal-fired power station blocks."



4. Strong fluctuations
in the wind power infeed (E.ON control area: 28.04. to 04.05.2003)

Page 6 – "The wind power infeed changes can occur in a relatively short time. This can be seen in FIGURE 5, which shows the wind power infeed pattern in the E.ON control area in the week of 17th to 23rd November 2003. It is clear that on 19th November, the wind power infeed dropped very sharply – by 3,640 MW within six hours, with an average value of 10 MW per minute."



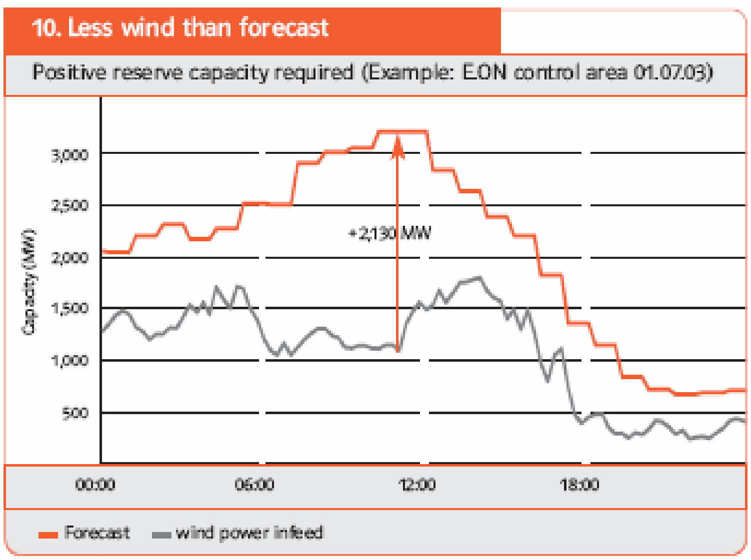
5. Brief decrease
possible in the wind power infeed (E.ON control area: 17.11. to 23.11.03)

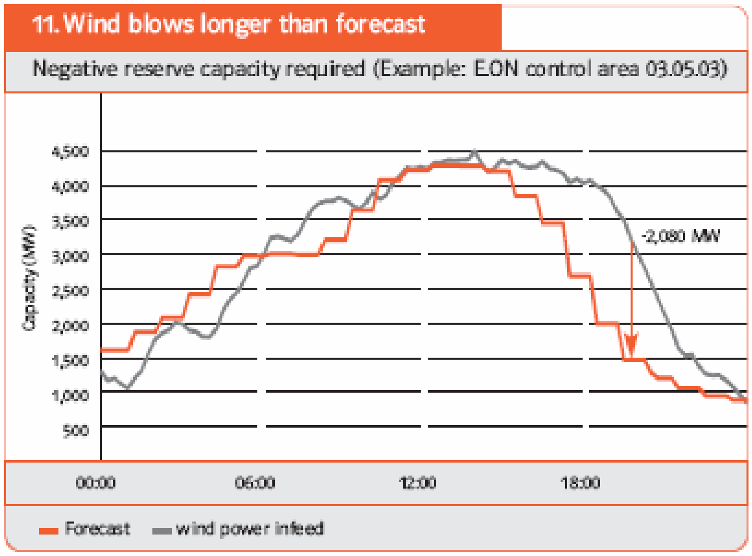
Page 7 "In order to also guarantee reliable electricity supplies when wind power plants produce little or no electricity – for example during periods of calm or storm-related shutdowns – traditional power station capacities must be available as a reserve. The characteristics of wind make it necessary for these "shadow power stations" to be available to an extent sufficient to cover over 80% of the installed wind energy capacity."

Page 9 – "Operational experience over the past few years has shown that reserve capacities in the order of magnitude of up to 60% of the installed wind power capacity must be kept for wind balancing in years when wind levels are normal. The need for reserve capacity and the resulting costs will therefore continue to rise in future parallel to the further expansion of wind power."

Page 9 – "In 2003, wind levels and therefore also the absolute fluctuation range of the wind power infeed were at above-average high levels. This meant that in retrospect, only reserve capacity amounting to around 50% of the installed wind power capacity actually had to be used."

Page 9 – "Of crucial importance to the wind-related demand for reserve capacity is the expected maximum forecast deviation and not, for example, the mean forecast error. This is because even if the actual infeed deviates from the forecast level only on a few days in the year, the transmission system operator must also be prepared for this eventuality and have sufficient capacity available so that a reliable supply is still guaranteed. FIGURES 10 and 11 (see below) show examples of the deviation between the actual wind power infeed and the forecast."





Page 10 – "In 2003, the expense required for balancing out the wind power fluctuations differed greatly in the four German control areas, depending on the wind power capacities installed there. Approximately half of the wind balance was done by E.ON Netz GmbH, even though its share of the ultimate consumer sales in Germany was only 30%."

Page 14 – "The operational behavior of wind power plants has so far differed greatly from that of traditional large power stations. Due to the massive and ongoing new expansion of wind power, it has therefore become increasingly difficult to guarantee the stability of the electricity supply – particularly in the event of a power failure. This means that wind power plants do not contribute to the same extent towards stabilising the grid frequency and to voltage stabilising as is the case with traditional power stations, which are actively involved in grid control.

But even more serious is the fact that wind power plants of the usual type have so far disconnected themselves from the grid even in the event of minor, brief voltage dips, whereas large thermal power stations are disconnected only following serious grid failures.

Faults in the extra-high voltage grid can therefore result in all wind power plants in the affected region failing suddenly. This means that within a very short time, the wind power supply of up to 3,000 MW can fail, thereby putting the grid stability at risk."

Figure #2 is a copy of the slide the CERTS representative presented at the stakeholder workshop that pertained to voltage issues:

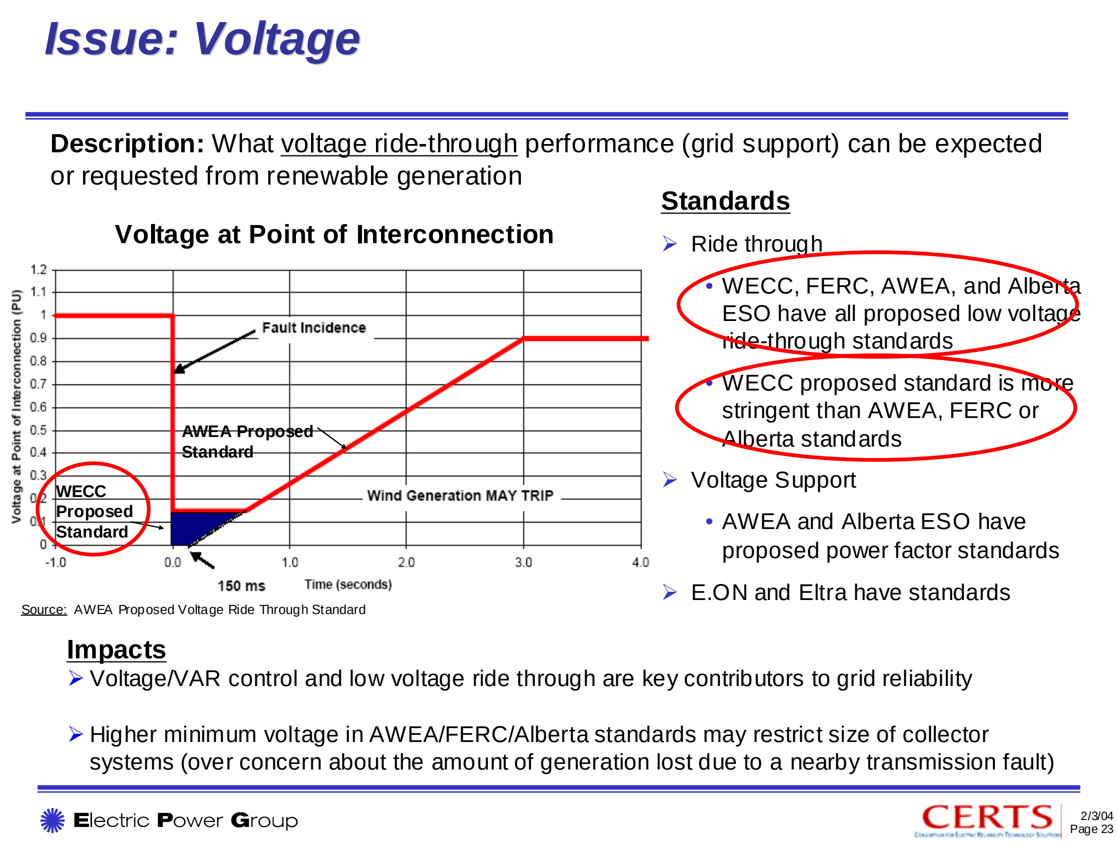


Figure # 2 – CERTS Presentation Slide #23

- As can be seen, the WECC proposed standard was presented as "proposed" as can be seen from the red circles in Figure #2, which is the CERTS presentation (slide #23). It was not presented as the "standard" as was suggested in the roundtable. The WECC proposed standard is the version dated Oct 21, 2004.

- The CERTS team used Figure #1 from AWEA's May 20, 2004, FERC filing (Standardizing Generator Interconnection Docket No. RM02-1-001, Petition for Rulemaking or, in the Alternative, Request for Clarification of Order 2003-A and a Request for Technical Conference of the American Wind Energy Association - http://www.awea.org/policy/gridcode.html), which indicates they should be able to ride-through a voltage decay down to 0.15 pu, at the point of interconnection.

- CERTS team juxtaposed the AWEA and WECC proposed standard to illustrate the system and reliability consequences of alternatives.

- The October 21, 2004 version of the WECC proposed standard (Sections 1 and 2) state:

    1. Generator is to remain in-service during system faults (three phase faults with normal clearing and single line to ground faults with delayed clearing) unless clearing the fault effectively disconnects the generator from the system.

2. During the transient period, generator is required to remain in-service for the low voltage and frequency excursions specified in WECC Table W-1 as applied to load bus constraint. These performance criteria are applied to the generator interconnection point, not the generator terminals.

Note: See the following WECC web page for a copy of the document: (http://www.wecc.biz/index.php?module=pnForum&func=viewtopic&topic=34)

The CERTS team's interpretation of the above sections is that the generator would have to ride-through a short duration close in fault down to zero (0) voltage. On this basis, the team concluded the WECC proposed standard was more stringent, since if the AWEA curve was adopted, then a wind generation plant would drop off following a short duration close in fault that resulted in a voltage decay below 0.15 pu. A consequence, if a less-stringent standard (defined in this manner) is adopted, is that it may impact the ultimate size of the collector station for this generation. That is, the potential impact would be based on the control area's ability to withstand the loss of a large quantity of generation for a single transmission contingency.

Note: At the time the workshop background material and the CERTS PowerPoint presentation were completed and sent to the CEC staff, the WECC's October 21, 2004, version was the only proposed LVRT standard posted on their site. We subsequently learnt that a revised version of the standard was proposed and posted on their web site on February 2, 2005, the day before the workshop. As of this date, no final standard has been adopted by WECC and what may finally get adopted may be the result of additional changes and revisions.

Action Items Going Forward:

The CERTS team will continue its research and fact finding in all aspects and issues related to this project and will provide the stakeholders with the latest information and facts available at the next scheduled workshop in late April.

STATE OF CALIFORNIA
ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION

In the Matter of:	**)**	**Docket No. 04-IEP-01F**
The Preparation of the 2005 Integrated	**)**	**Re: Transmission-Renewables**
Energy Policy Report (Energy Report)	**)**	**Operational Integration Issues**

REPLY COMMENTS OF THE CALIFORNIA WIND ENERGY ASSOCIATION ON OPERATIONAL INTEGRATION ISSUES ASSOCIATED WITH TRANSMISSION AND RENEWABLE GENERATION

The California Wind Energy Association (CalWEA) appreciates this opportunity to provide these written comments in response to the February 3, 2005, IEPR Committee Workshop on Transmission-Renewables Operational Integration Issues and related materials. We comment on the January 17, 2005, "Assessment of Reliability and Operational Issues for Integration of Renewable Generation: Background Material for California Energy Commission Stakeholder Workshop" ("Background Report"), some of the presentations made at the workshop, and the associated overall project ("Project") which is scheduled to culminate in a June 2005 report and recommendations, in time to be integrated into the *Integrated Energy Policy Report* ("IEPR") process. These comments build upon the oral comments that we provided at the workshop, and respond to the specific questions posed in Attachment A to the workshop agenda.

A. Summary of Comments

As there is a tremendous amount of subject matter covered by this Project, we do not address in these comments every topic and statement in the materials. Rather, we have tried to categorize the problems and illustrate them with examples.

In general, we find that the Project has not been well-conceived. It is disorganized and lacks focus. Its presentation of the issues fails to reflect current wind technology, current analytical thinking on wind integration, and recent and ongoing institutional efforts addressing wind-related operational issues. It unfairly attributes to wind problems that are not unique to wind, and fails to take an integrated system view when a broader view is necessary to promote efficient operation of the grid overall. In particular, our views on the effort are as follows:

- The Project is not focused. It does not distinguish between relatively routine issues (such as voltage regulation) that are being or will be handled in the appropriate technical forums, and "problems" that are not being adequately addressed.

- The Project suffers from an alarmist quality and perpetuates myths (e.g., that wind requires dedicated back-up resources).

- The Background Report reflects past historical issues, such as insufficient VAR support and lack of wind forecasting, without adequately accounting for technological advances and evolving market rules which have obviated many of those issues.

- The issues list includes many issues that are not appropriately characterized as "renewables operational integration issues" because they are issues that are not caused by, or are not uniquely associated with, renewables. The IEPR process should address (and maybe already is addressing) these issues, but it should not be done in the context of *renewables* operational issues. Treating regulation and integration issues in isolation with respect to wind is not productive.

- The Project appears to be disconnected from, and uninformed by, the PIER program's excellent work on the RPS Integration Cost Studies, which is on-going. The efforts should be coordinated.

- The Project appears to be uninformed by the work well underway at FERC, the Utility Wind Interest Group, WECC, and elsewhere. Far more comprehensive summaries of this work, as well as up-to-date analyses on many of these issues, are available but are not reflected in the Project.[1].

Recommendations:

(1) The IEPR's discussion of renewables integration/operational issues should draw from the California-specific, detailed analyses that the PIER program team has conducted and continues to conduct in many of these topic areas, rather than from this Project's laundry list of potential issues drawn from myriad studies that may or may not be relevant to California's current situation.

(2) This Project should be reconsidered and refocused for the 2006 IEPR process. The effort should focus on the system as a whole, with an eye toward optimizing grid operations in view of the state's mandated renewable energy goals. The effort should consider the most efficient integration of all resources (and large single loads), separating out issues associated with resource or technology characteristics and issues caused by contractual constraints.

[1] See, e.g., *Wind Power in Power Systems*, Edited by T. Ackermann, © 2005 John Wiley & Sons, Ltd, ISBN 0-470-85508-8 http://www.windpowerinpowersystems.info/index.html. See also, generally, the materials available on the website of the Utility Wind Interest Group, www.uwig.org

These criticisms are not meant to suggest that there are no *renewables-specific* operational integration issues deserving of California Policymakers' attention. But they are relatively narrow in scope. We identify some that we believe are deserving of attention.

B. Responses to Questions 1, 2 and 4

We address questions 1, 2 and 4 together: (1) Is the List of Issues (in Attachment A) Valid? (2) Have the Issues Been Accurately Characterized? and (4) Is the Study Headed in the Right Direction and Adequately Focused?

In short, no, the list of issues is not valid as an appropriate scope for this effort and, no, the study is not headed in the right direction nor is it adequately focused, for the following reasons.

1. The Project is not focused. It does not distinguish between relatively routine issues that are being or will be handled in the appropriate technical forums, and "problems" that are not being adequately addressed.

In general, there is a "can't see the forest for the trees" problem in this effort: the work to date fails to sort through the myriad "issues" to identify those that are deserving of California policymakers' attention. The Background Report, and some of the workshop presentations, focus on past historical problems and fail to put into perspective and differentiate those that have already been addressed The Project does a poor job of informing readers of the efforts now underway in various responsible forums, such as the Western Electricity Coordinating Council (WECC) and the Federal Energy Regulatory Commission (FERC) that are addressing many of the technical issues described.

For example, the Background Report, and in some cases the workshop presentations, considers at some length voltage performance (issue number 6) and electrical governor performance (issue number 7) but does not place these issues in the proper perspective. The Report asks arcane questions like "What is the relationship between the energy output and the electrical frequency for intermittent generation during disturbances?"[2] (without contributing any new insights or proposing analyses on such topics), but does not point out that these issues are being handled adequately by WECC, FERC, and others. Nor does the Report anticipate the system impact of new operational standards being developed by the FERC in its wind interconnection docket.[3]

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[2] Background Report, p. 12.

[3] See Assessing the State of Wind Energy in Wholesale Electricity Markets, FERC Docket No. AD04-13. In this docket, FERC is developing SCADA system and VAR requirements for new projects. A new North American Reliability Council (NERC) task force is also addressing these types of issues (see ftp://www.nerc.com/pub/sys/all_updl/docs/news/news0105.pdf).

There is no reason to expect that these issues cannot or will not be appropriately and successfully handled in these forums. Similarly, some issues can be expected to be addressed during individual generator interconnection processes, and others may be addressed though California's changing market design.[4] The report would better serve policymakers if it were to broadly characterize the issues, describe the progress being made on them in other forums, and identify any issues that are not being addressed and which California policymakers should attend to (we identify a few such items in Section D, below).

Alternatively, if the Energy Commission wishes to delve into these technical issues in order to assist other agencies that are making decisions on these issues, it should commission serious work on the topics (as it is, in fact, doing through the PIER program – see Section C, below).

2. The Project suffers from an alarmist quality and perpetuates myths. The Project does not differentiate between near-term integration issues, and long-term integration on a far larger scale.

The Background Report, and in some cases the workshop presentations, create a "sky is falling" impression by discussing issues without putting them in the proper perspective. The proper perspective is that none of the wind-specific issues are "showstoppers" to meeting the RPS goals; rather, they are manageable technical issues that can be resolved as wind penetration increases gradually. While we need to be on our toes, we are not likely to encounter insurmountable problems as we achieve the state's RPS goals with the amount of wind capacity anticipated by the Energy Commission. Some of the problem appears to lie in the authors' reliance on stakeholder interviews rather than interviews with those most knowledgeable on these issues.[5] Many of the statements in the Background Report are relevant only to existing projects and obsolete technology. The Report fails to account for planned technology improvements, or the types of evaluation tools commonly in use today.[6] The result is that the report perpetuates the myths that many renewables integration studies – including the CEC's own -- are slowly but surely dismantling.

Often, the Background Report and the project team's workshop presentations suggest problems unsupported by fact or accurate citations to the literature. For example,

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[4] For example, if locational marginal pricing is introduced in California, it will affect the "curtailment priority" addressed in the Background Report's congestion question #2 (p. 13), "Where will renewable energy fit in the curtailment priority ranking when congestion exists?"

[5] Among the many knowledgeable people that the project team could have interviewed are: the authors of the RPS Integration Cost Studies and other renewables integration experts; FERC, NERC and WECC committees or staff; wind turbine manufacturers; and wind forecasting companies. We note also that neither CalWEA nor any of its members were interviewed.

[6] The excellent workshop presentation by Nick Miller of GE Energy addresses many of these issues, but that material is not reflected in the Project materials and it is unclear what, if any, GE's role in this effort is. We are pleased to learn, however, that Miller will be a part of the PIER project's team on these issues, as stated by George Simons at the February 3 workshop.

the summary report on wind energy in E.ON. Netz's central Germany utility system was not appropriately presented.[7]

First, the E.ON Netz report (a glossy 16-page color brochure that appears to have been designed to cast wind in a negative light) was not put in the proper perspective: installed wind capacity accounts for 33% of E.ON Netz's system peak demand – far beyond what California will achieve under its 20% renewables requirement.

Second, the E.ON report (and the Background Report and presentation) perpetuates the antiquated notion that reserves must be dedicated specifically to wind -- in this case that the wind energy on E.ON's system requires a "shadow reserve" of 80% of installed wind capacity. But this is the myth that Effective Load Carrying Capability (ELCC) studies put to rest. ELCC studies measure the contribution made by each system resource – none of which are perfectly dependable, and each of which back each other up to some degree -- to the reliability of the system. The ELCC studies conducted as part of the RPS Integration Cost Analyses[8] ("RPS Analyses") showed that existing California wind resources add reliability value to the system in the amount of 24%, on average, of their nameplate capacity. The E.ON "80% shadow reserve" statement can likewise be viewed as meaning that E.ON's installed wind generation provides reliability value equivalent to 20% of its installed generation – not bad given the 33% penetration level of installed wind capacity relative to peak load.

Finally, the E.ON.Netz Report (at p. 14) notes that new regulations to correct many of the operational issues discussed were adopted in August 2003, but this was not noted or discussed in the Background Report or the presentation. This critical omission is another indication that the Project team is focusing on past problems rather than current practices.

There are more relevant studies than that of E.ON Netz' available (not the least of which are the CEC's own RPS Analyses). For example, a detailed technical study commissioned by the New York State Energy Research and Development Authority (NYSERDA) recently concluded that the New York State bulk power system can reliably accommodate at least 10% penetration (3,300 MW) of state-of-the-art wind generation with only minor adjustments to its existing planning, operation, and reliability practices.[9]

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[7] See p. 29 of the Background Report, and vugraph pages 7-9 in "Assessment of Reliability and Operational Issues for Integration of Renewable Generation," Presented by Jim Dyer at the Energy Commission Committee Workshop, February 3, 2005.

[8] See "California RPS Integration Cost Analysis – Phase I: One-Year Analysis of Existing Resources," a consultant report to the Energy Commission, December 2003 (CEC Report No. 500-03-108C), and the subsequent Phase III report (P500-04-054, July 2004).

[9] See: "The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations," February 3, 2005 (draft report). Available at: http://www.nyserda.org/rps/default.asp. See also "Xcel Energy and the Minnesota Department of Commerce Wind Integration Study – Final Report" September 28, 2004 (http://www.state.mn.us/mn/externalDocs/Commerce/Wind_Integration_Study_092804022437_WindIntegrationStudyFinal.pdf). This study suggests that up to 15% of Xcel's control area can be provided by wind energy for an integration cost of no more than $4.40 per MWh.

Failure to analyze the California situation in a comparably competent manner and comparable depth is simply not a worthwhile effort and diverts valuable resources.

3. The issues list includes many issues that are not appropriately characterized as "renewables operational integration issues" because they are issues that are not caused by, or are not uniquely associated with, renewables.

The following identified issues are not appropriately characterized as "renewables operational integration issues" for the reasons stated. The Commission should address these issues in the IEPR as they relate to *all or many types of resources on the system*. If these issues are addressed solely with regard to renewables, (a) it would unfairly suggest that renewables (wind in particular) are the cause of these "problems" and (b) it would fail to treat the problems in the proper holistic context and therefore fail to identify appropriate solutions.

Issue 1: Load following generation and compliance with North American Electric Reliability Council Control Performance Standards

The questions asked in relation to these topics on pages 6 and 7 of the Background Report are not uniquely related to renewables. For example, "What options are available to limit the high rate of change of energy production from intermittent energy production?" (Background Report, p. 7) perpetuates the myth that wind and other intermittents impose unique burdens on the system. In fact, wind's ramping rate is no worse than that of block-scheduled generation and some loads, such as the State Water Project.

The small regulation impact of intermittent renewable generation is confirmed by the RPS Analyses. Those studies point out that all loads and generators require regulation and load following services at some time, and that these services exist without the presence of renewable resources.

- Regarding load following, the RPS study concluded, "there is no significant impact of existing renewable generators in the load following time scale. These results are sufficiently robust so that little impact should be expected if reasonable amounts of additional renewable resources are added to the system."[10]

- Regarding regulation costs, the RPS study concluded that solar facilities provide a small regulation benefit to the system, while wind and geothermal facilities impose a small regulation burden (biomass plants imposed no regulation burden). "In aggregate," the study says, "*the wind regulation burden is lower (on an energy basis) than that imposed by loads*"[11] (emphasis added). As with load following, the regulation results are sufficiently robust

[10] See Note 8, s*upra*, p. 74 of Phase I study.
[11] *Ibid*, p.xii-xiii.

so that little impact should be expected if reasonable amounts of additional renewable resources are added to the system.

The authors of the RPS Analyses are now evaluating the much larger amounts of wind that are anticipated under the 20% RPS scenario. Our understanding is that their present expectation is that the regulation costs will not change significantly, and may even go down due to increased geographic diversity, and that the load following requirements will remain manageable.

Because ancillary service issues are not uniquely related to wind, nor do we have reason to expect that meeting the RPS goals will lead to significant impacts, there is no reason to belabor issues related to NERC standards, etc., in this report. The IEPR should report on the findings of the RPS Analyses on these topics, as well as similar studies from other states, all of which show remarkably comparable results.

Issue 2: Minimum load challenges and the potential need for storage

Minimum load challenges are not uniquely related to renewables and should be discussed in a broader context so as not to suggest that renewables are uniquely to blame. The DWR contracts, for example, have created significant minimum load problems. Minimum load challenges are also presented by nuclear plants and are increasingly coming from new CCGT generators that cannot cycle in reasonable time intervals. These CCGTs are becoming an increasingly large portion of the generation mix -- far too large in relation to the integration problems they pose and in view of their detrimental environmental and fuel-use issues.

Moreover, minimum load issues are being considered in the RPS least-cost, best-fit resource evaluation process, because the utilities ascribe “dump energy” costs to renewables producing during minimum load hours (during which time power from the rigid DWR contracts is already flowing – a major source of the problem).

To the extent that high levels of renewables will contribute to minimum load challenges – and this issue will be specifically evaluated in the ongoing RPS Analyses -- the utilities are free to negotiate curtailment with sellers. It is very likely that significant curtailment during minimum-load hours during the spring runoff is possible without significantly driving up the cost of wind energy. If the Project staff believes that this “solution” deserves more attention by policymakers (and if it is not already being address as part of the RPS Analysis), it could study the issue and make recommendations (see section D, below). But the minimum load problem should not be ascribed to renewables uniquely, or even in significant part. Nor would it be appropriate to suggest that clean renewable generators should not generate while fossil generators, which can cycle off, are allowed to remain on line. Instead, the IEPR’s focus should be on promoting the appropriate contractual or design choices for fossil fuel generators, and provisions to correct those faulty contracts.

As for "the need for storage" – i.e., "should energy storage be required for intermittent energy additions?" (Background Report, p. 8), the question is inappropriate. First, the RPS Analyses are likely to show that the cost of integrating significant amounts of additional wind into the system are low – so adding expensive storage would be unjustified, at least until wind penetration well exceeds currently anticipated levels. Second, as noted above, intermittent resources are not uniquely to blame for minimum load problems. The possible need for storage is at least as much associated with design and contractual choices associated with conventional generation, and with transmission alternatives, as it is with renewables. Renewables should not be singled out as is being done here. Finally, it would make no sense to build expensive new energy storage systems when the state's existing storage resources and capabilities have not been assessed to see whether they could provide some of the services the Background Report calls for (assuming they are needed in the first place), or whether these resources could be better used to maximize overall system efficiency. In sum, the storage issue is much larger and should be much more broadly focused than is being done in this effort.

Issue 3: Reserves

The section in the Background Report on "Reserves" does not clearly define the many complicated topics that it appears to be addressing. The set of questions relate to issues of capacity credit, reserve margins, and ancillary services (operating reserves). We addressed the capacity credit/shadow reserve issue in section, B.2, above, and the ancillary services issues in the two subsections immediately above.

The issue of reserve margins and related requirements on load-serving entities is being addressed presently by the CPUC in its Resource Adequacy Proceeding. The CPUC is establishing the appropriate amount of "qualifying credit" for each type of renewable resource for purposes of meeting reserve requirements. The issue is not unique to renewables, and deserves no discussion here (except perhaps to note that it is being addressed), unless the Project staff has identified problems with and potential solutions to the CPUC's treatment of renewables (which does not seem to be the case).[12]

Questions such as "Will there be a need for shadow generation as we introduce greater amounts of intermittent resources in the state's resource mix" (Background Report, p. 9) falsely imply that intermittents require dedicated back-up resources. Generation resources of all types operate as part of a robust set of system resources. Each resource contributes a certain amount of reliability to the system, and no generator is perfectly reliable. Reserve requirements are established for the system as a whole, and not to specific generators (as the quoted question would imply). Wind generators are

12 CalWEA has been participating in the CPUC's Resource Adequacy proceeding on the topic of the qualifying credit ("QC") assigned to wind. We advocated that the CPUC use the Effective Load Carrying Capacity results of the RPS Integration Cost Studies to determine the QC for wind. Instead, the CPUC has chosen to use historical performance on a monthly basis, computed over the QF Standard Offer 1 on-peak period. We have urged the CPUC to clarify that the entire SO 1 on-peak period (noon to 6:00 p.m. summer weekdays except holidays) will be used over the previous five years. Workshop discussions suggest that this approach will be used. If so, we believe this methodology will appropriately value wind's capacity credit.

assigned a certain amount of capacity credit (as is being done in the CPUC proceeding) for purposes of meeting resource adequacy requirements, and the capacity value of proposed wind projects is evaluated similarly in the RPS least-cost, best-fit evaluations based on the capacity analysis results in the RPS Integration Cost Studies. That the Project staff would raise "shadow reserves" as an issue reveals its misunderstanding of these issues.

Issue 8: Congestion
Issue 9: California Imports and Western Electricity Coordinating Council transfer path capability

There is a significant amount of work going on in these topic areas, in various forums, that is not referenced in the Background Report. These forums include the Seams Steering Group for the Western Interconnection (SSG-WI) and related efforts such as the Southwest Transmission Expansion Plan (STEP) process. These efforts consider, but are appropriately not limited to, anticipated renewables developments in the west. In addition, there are two CPUC-initiated transmission planning groups – the Tehachapi Collaborative Study Group and another for the Imperial Valley – that are addressing local congestion issues. This Project should summarize these efforts and indicate where more work, if any, needs to be done.

Issue 10: Resource attribute requirements and retirement risk of California-controllable generation

The questions in the background report (p. 13) make clear that this is not an issue related uniquely to renewables. See comments on Issue 1, above.

4. Some issues are not clearly described

Issue number 5, "Existing contracts and standard products," was not described, or at least not clearly identified, in the Background Report, so it is impossible to say whether it is appropriate for inclusion in the report or adequately focused.

C. The Project Appears To Be Disconnected From, And Uninformed By, The PIER Program's Work On Renewables Integration Issues

While the Project briefly summarizes the CEC PIER Program's RPS Integration Cost Analyses, it appears not to have learned from them, as discussed in our comments above. Nor does this effort appear to be coordinated with the PIER program's ongoing related work in this area.[13] It should be. Indeed, the IEPR should draw from the California-specific analyses that the PIER program team is conducting in many of these

[13] It is our understanding that this work is being handled through UC Davis's California Wind Energy Collaborative.

topic areas,[14] which will address directly and concretely a number of the issues that are only generally and vaguely addressed by this Project. On those issues that the PIER project is not addressing, this Project should seek the input of the PIER project team in determining which issues are worthy of highlighting and which are not, as the capabilities of the PIER project team appear to be better suited to these issue areas.

D. Response to Question 3: Are there issues or potential issues that have not been captured on the list?"

The criticisms above are not meant to imply that there are no *renewables-specific* operational integration issues deserving of California Policymakers' attention. But they are relatively narrow in scope. Here are a few that have not been identified that come to our minds[15]:

- What are the ancillary service costs/benefits of, and improved operating flexibility associated with, connecting Tehachapi south and north versus south only? (CAISO staff has indicated they believe the benefits of North-South interconnection to be significant, but have not had the resources to analyze them.)

- Is it feasible to connect 900 MW to 1,500 MW of Tehachapi wind generation to PG&E via Big Creek Corridor and the Helms line to Gregg by the use of FACTS devices or Phase Shifters at the intersection of the Big Creek lines and Helms lines? Can Helms Pumped Storage be effectively coordinated with Tehachapi wind to form a higher quality or lower cost integrated resource for the system? How best would Big Creek, Helms, and Tehachapi wind be integrated, and what does the energy delivered look like at each delivery node? How does Pastoria and other conventional generation in or near the paths fit into such an optimum energy and capacity product, and what impacts, if any, would be imposed on any such conventional generators, or what portion of the regulation task should they carry?

- What procedures could the ISO implement to better balance wind resources?

- What would the benefits be of requiring wind generators to curtail during minimum load hours during the spring run-off? How much curtailment could be required of wind generators during these hours without significantly driving up the cost of wind energy? What steps would need to be taken to provide the ISO with the ability to directly curtail wind turbines? What curtailment provisions should be made in the power purchase contracts now being signed? What

[14] It is our understanding that the PIER program's RPS Analysis team is in the process of analyzing ancillary service costs and capacity credit values under the 20% RPS scenario, and that related PIER program efforts will address other topics raised in this Project.

[15] The Project staff does not appear poised to do the types of analysis that would be required to answer these questions, however. The PIER program's integration issues team may be in a better position to analyze these issues.

contractual and design mandates should be placed on new and repowered conventional generation such that it can provide regulation and curtailability?

- There are a variety of institutional barriers that should be looked at:

    - Although wind's ramping rate is not unique or extreme as compared to other resources, the CAISO does not know which direction the wind generation is moving in *because the utilities refuse to enroll their QF wind projects into the CAISO's wind forecasting program.* How can the utilities be encouraged to participate? (It should be recognized, however, that this problem will not arise with new wind projects, because they are likely to participate in the CAISO's forecasting program.)

    - There are an insufficient number of meters in wind resource areas. Currently, for example, the CAISO meters the entire Tehachapi area with only one or two meters, both far removed from the generating sites. Such poor metering practices produce insufficient and low-quality information on wind generation for system operators and also compromise proper analysis.

    - How can we get better data from the CAISO for renewables integration analyses? After two years, the RPS Integration Cost Analysis team has still not been able to obtain the data it needs to conduct robust analyses. But these are the analyses we need to determine what "problems," if any, are associated with renewables. Sufficient CAISO meter data should be available to the RPS Integration Cost team (and perhaps to the public) without restriction.

More importantly, the IEPR should look at how operation of the system as a whole can be optimized. We noted above a number of the issues that have been identified in this report that would be more appropriately addressed in a report *addressing system-wide issues*. In addition, we would add these:

- Can existing hydro and conventional resources be coordinated with intermittent renewables in a way that increases overall system reliability and efficiency and reduces transmission costs? This appears to be a potentially high value gain for the overall system, but is a complex issue to analyze.

- What is the best overall coordination strategy for the integration of intermittent renewables and hydro with conventional generation to minimize the construction of new LNG terminals, and for the reduction of GHG emissions?

- Can the CAISO N-1 and N-2 criteria be increased (with WECC approval) with increased reserves, generation coordination, storage, and other system changes, thereby increasing Path transfer ratings, and otherwise lower system costs and increase efficiency and reliability?

- To what extent should the capacity of the main North-South or South-North corridor, Path 15 and Path 26 and other nearby potentially parallel paths, be increased in order to increase operating flexibility, reduce ancillary services costs, lower the cost of energy, and better integrate renewables into the statewide mix? Should Tehachapi be a node in this Path?

- Should Path 65 be tapped for renewables transmission capability? Should new DC links, or existing AC links converted to DC be developed to create a better overall transmission system for the state? Are charges associated with use of Path 65 appropriate and are they causing misuse or under-use of this important path?

- What system costs are associated with the trend toward CCGT technologies with less flexible capabilities, and with the DWR contracted facilities, and what should the state be doing to reverse this trend, or to correct contractual errors?

We appreciate this opportunity to comment, and would be pleased to meet with the Commission and Project staff to discuss these issues further.

Respectfully submitted,

__________/s/____________

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February 17, 2005

SOUTHERN CALIFORNIA
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Gary L. Schoonyan
Director
San Francisco Office

February 17, 2005

California Energy Commission
Dockets Office
Attn: Dockets No. 04-IEP-1F
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Dear Commission:

Re: Southern California Edison's Comments Regarding the "Assessment of Reliability and Operational Issues for Integration of Renewable Generation"

Pursuant to the Commission's 2005 Integrated Energy Policy Report Committee's Consultant Report titled, "Assessment of Reliability and Operational Issues for Integration of Renewable Generation." and the questions contained within the Agenda for the February 3 workshop, Southern California Edison would like to take this opportunity to provide the enclosed comments and responses.

We would like to also commend the CEC for embarking on this needed and timely effort. In order to collectively fulfill the State's aggressive renewable vision, we need to understand all the operational implications associated with integrating significant amounts of non-dispatchable and intermittent resources in a safe, reliable and efficient manner. Proceeding in such a way will only enhance the likelihood of reaching our goals in a timely fashion, while benefiting consumers.

If you have any questions regarding these comments, please call me at (916) 441-4114.

Sincerely,

GSchoonyan

Gary Schoonyan

Enclosure

cc: Commissioner John L. Geesman
Commissioner James D. Boyd
Commissioner Jackalyne Pfannenstiel

601 Van Ness Ave.
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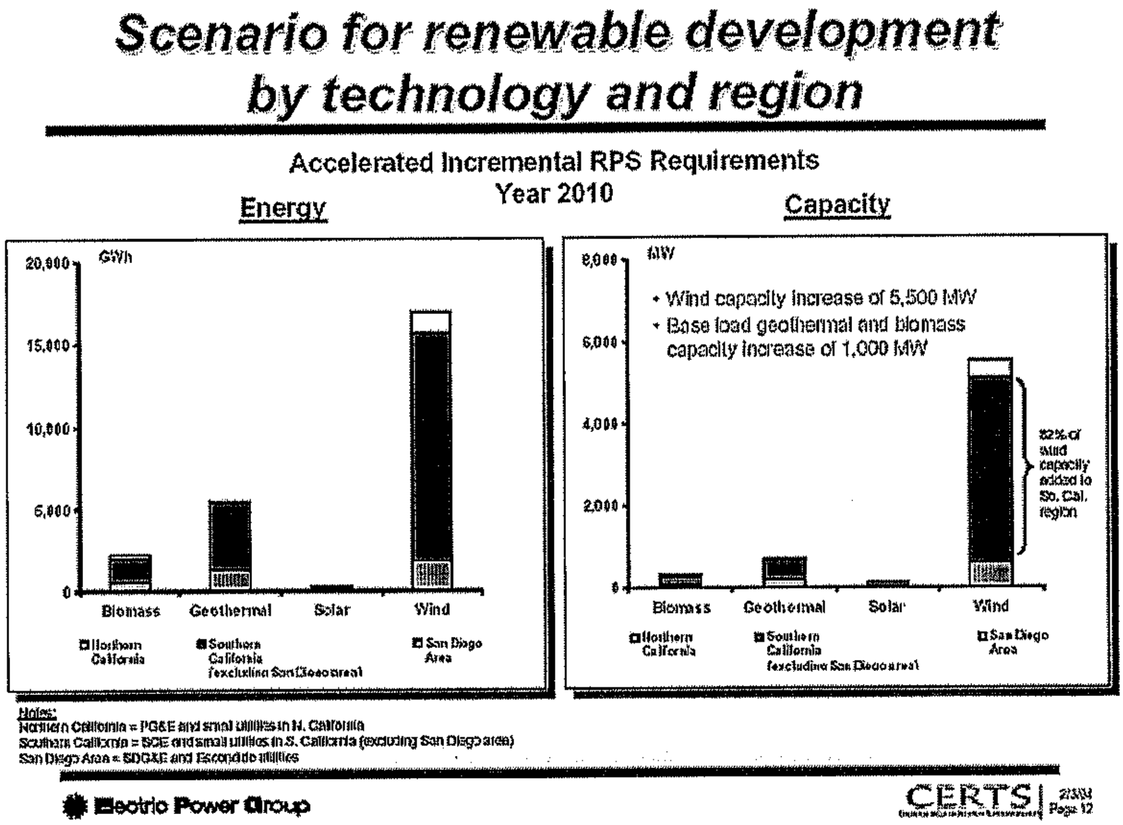
San Francisco, CA 94102
415-929-5518
Fax 415-474-3080

SCE's Comments on the Consultant Report Titled "Assessment of Reliability and Operational Issues for Integration of Renewable Generation".

The list of issues that have been identified are accurate and the study appears to be headed in the right direction. To the extent there are operational, planning and interconnection concerns, we believe they need to be addressed sooner rather than later, so that effective methods and approaches can be developed and implemented to fulfill the State's aggressive renewable objectives, without jeopardizing the quality, reliability, and cost of the power Californians use.

Along these lines, there was one key fact that appears to have gotten lost in the discussion. Given that the majority of renewable and wind potential is located in or near SCEs service territory, coupled with the desire to significantly increase renewable resources, there is a high likelihood that SCE will be required to integrate levels of intermittent and non-dispatchable resources far in excess of our own obligations (see following page). As such, the integration issues addressed by the study will likely be greatly amplified for SCE compared to the State's other electric systems. This has become increasingly relevant given the CPUC's July 8, 2004 Decision directing local utilities to assume a key role in providing local area reliability, rather than relying solely on the ISO. As such, the additional burdens associated with integrating much of the State's renewable resources, could fall to SCE.

There are, however, ways to mitigate, including having the other major utilities construct transmission to these area of high renewable potential. SDG&E has already indicated that they are considering a 500kV line to the Imperial Valley in 2010 to access geothermal power. PGandE could likewise construct 500kV facilities to the Tehachapi area, which would not only provide PGandE with direct access to a major source of wind potential, but also provide the State with additional infrastructure to help mitigate the Z-26 congestion concerns, providing those facilities were to interconnect with SCE's proposed 500kV Antelope facilities. In fact, LADWP could also access this region.



Secondly, several participants commented that "this process should not force wind resources to resolve the existing problems with the systems as a whole" SCE does not believe that the study is requiring the new renewable resources to correct the problems associated with the system. However, given the anticipated large increase in these non-dispatchable and intermittent resources, we do need to address the system reliability and operational issues, along with methods to accommodate or correct any adverse impacts.

SCE also believes the study should look at the operational issues associated with other types of renewable resources as they may encompass different integration issues and remedies.

Finally, there was a comment suggesting that fluctuations in wind don't approach the scheduling changes associated with DWR contracts, and as such, there shouldn't be an integration concern. This simply isn't true. There are substantial differences in reliability and operational integration associated with DWR's known hourly schedule changes which occur at a specified time and ramp period, as compared to the unpredictable and instantaneous changes related to intermittent resources. The fact that the CEC assumes little capacity value for wind for resource adequacy purposes, thus requiring additional reserves, should not go unnoticed.

Additional Questions for Stakeholder Panel

1. Will the retirement of conventional gas fired units and the growing percentage in the generation mix of gas fired Combined Cycle Gas Turbine units, which have little or no ability for system regulation, have a major impact on the state's ability to effectively integrate renewable resources? If so, how?

SCE Response: SCE has not performed an assessment to determine the potential impact of the retirement of gas fired units on system regulation. In general, to the extent the supply of regulating resources decreases, it is likely that the price for regulation services would increase. In addition, a significant increase in the amount of intermittent resources like wind generation will increase the demand for regulation services.

2. In the case of the California Independent System Operator control area, who is responsible and what is the process to assure that it has an adequate resource mix, with the necessary attributes, to meet the control area's ancillary service requirements?

SCE Response: The CAISO has the responsibility to ensure that sufficient resources are dispatched to meet ancillary service requirements for its control area. The CAISO operates a day-ahead ancillary services market to ensure sufficient ancillary services are available. Resources that provide ancillary services to the CAISO must meet minimum WECC operating criteria (e.g. non-spinning reserve must be available within 10 minutes). The CAISO is not responsible for ensuring there is a particular resource mix (e.g. certain percentage of gas-fired units). Currently there is not a requirement for an entity to ensure that the CAISO control area has a given resource mix to meet ancillary service requirements.

3. What steps are needed to assure that California customers get the full benefit (e.g., deliverability and integration) of the renewable resources that are connected to the grid?

SCE Response: Deliverability of renewable resources is addressed through the generator interconnection studies. Under FERC policy, generators are responsible for generator interconnection facilities (including the line from the plant to the transmission grid or "gen-tie") and any transmission network upgrades to make the generation deliverable. Since these upgrades can be costly, some renewable resources are not able to obtain funding for the upgrades. FERC policy does not permit transmission utilities to recover the cost of gen-ties in transmission rates. SCE also needs CAISO approval of transmission network upgrades to enable cost recovery through transmission rates. SCE has requested FERC to create a new category of transmission upgrade – a "trunk line" that would connect wind resources to the transmission network – and asked that FERC permit recovery of such costs in transmission rates as a way to facilitate needed expansion to accommodate renewable generation. In addition, SCE is working with the CAISO to gain their approval of transmission network upgrades to accomodate additional wind generation in the Tehachapi area.

4. What do California and others in the Western Electricity Coordinating Council need to do to maintain existing transmission path ratings that could be impacted as a result of significant changes in the region's generation resource mix (e.g., addition of baseload resources with limited or no governor response)?

SCE Response: The CPUC's resource adequacy requirement is intended to be the mechanism through which sufficient resources are procured to allow the CAISO to reliably operate the grid. Through the CPUC's resource adequacy workshop process, criteria and procedures are being developed to enable the CAISO to have sufficient resources in its control area to reliably operate the grid. The CAISO is also redesigning its market to better align the market with reliable grid operations. Stakeholder participation in the CPUC and CAISO efforts, in addition to the WECC transmission path rating process, is vital to ensure impacts of generation resource mix are fully considered.

STATE OF CALIFORNIA
ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION

In the Matter of:	)	Docket No. 04-IEP-01F
The Preparation of the 2005 Integrated	)	Re: Transmission-Renewables
Energy Policy Report (IEPR)	)	Operational Integration Issues

COMMENTS OF AMERICAN WIND ENERGY ASSOCIATION ON OPERATIONAL INTEGRATION ISSUES ASSOCIATED WITH TRANSMISSION AND RENEWABLE GENERATION

The American Wind Energy Association[1] (AWEA) appreciates this opportunity to provide these written comments in response to the February 3, 2005, Integrated Energy Policy Report (IEPR) Committee Workshop on Transmission-Renewables Operational Integration Issues and related materials. In particular, AWEA comments on the materials circulated at the workshop, and the associated overall project ("Project"), which is scheduled to culminate in a June 2005 report and recommendations, in time to be integrated into IEPR process.

Summary of Comments

AWEA applauds the Commission efforts to define and refine the operational issues associated with wind integration. In no way, however, does AWEA believe that the current record in this proceeding supports any conclusions about whether policy, procedural or regulatory changes are warranted. Indeed, AWEA recommends that the "next steps" identified in the Project - specifically, the development and risks of various policy changes - be suspended immediately. Rather, AWEA recommends that the Commission embark upon a comprehensive and detailed study of the impacts of high-penetration renewables development, as was done by NYSERDA[2]. Policy alternatives should only be considered in the light of credible, detailed analysis.

Comments

AWEA supports the Commission's clear focus on investigating the impacts of renewable generation on the interconnected electrical grid. We have reviewed the presentations offered in the February 3 workshop and find that for the most part, they represent a reasonable balance of appropriate intellectual curiosity in identifying potential issues with high-penetration renewables scenarios.

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[1] AWEA is a national trade association representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind energy resources in the United States. AWEA members include wind turbine manufacturers, component suppliers, project developers, project owners and operators, financiers, researchers, renewable energy supporters, utilities, marketers, customers and their advocates.

[2] See "The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations," February 3, 2005 (draft report). Available at: http://www.nyserda.org/rps/default.asp.

However, while AWEA supports the identification of issues, it has significant concerns with what it believes to be inappropriate conclusions that policy makers could draw from inapplicable, preliminary, and tenuous linkages and assertions presented at the workshop, particularly those presented by CERTS and the Electric Power Group (CERTS/EPG). Many of those linkages and assertions have been adequately highlighted in the comments of CalWEA and need no further discussion here.

However, the one area of the CalWEA comments that deserves further emphasis is the surprisingly narrow list of interviews performed by CERTS/EPG prior to the development of the February workshop materials. While the proponents claim to have reviewed dozens of reports and articles, they appeared to interview few of the authors of those reports. In addition, AWEA finds it surprising that our members, in spite of being the largest operators of renewables technologies within the State, were not, with one exception, contacted in the development of the workshop materials.

AWEA recommends that the Commission suspend the current efforts - in particular the next steps proposed in the Project. These next steps, as reported in the background materials, and beginning with step 6 would be to:

6. Evaluate alternatives to address reliability and operational integration issues, including resource management, operating procedures, and regulatory policies. Assess pros and cons for alternative policy options.
7. Review options in the areas of policy, procedure, and standards at a second stakeholder workshop. (April 2005)
8. Prepare a final report and recommendations. (June 2005)

Indeed, policymakers should only consider operational or regulatory intervention (as in step 6) in the face of a credible, California-specific, high-penetration renewables study that indicates such intervention is necessary. To do otherwise is likely to introduce significant development risk, delay the construction of new facilities, reduce the consumer welfare associated with renewable generation, threaten RPS goal attainment and create a host of other unintended consequences.

In order to develop a record that will allow reasoned decision-making, AWEA recommends that the Commission immediately dedicate its considerable resources to the development of a comprehensive and detailed study of the impacts of integrating renewables at high penetration rates.

This simulation would model all relevant components of the interconnected grid, and would attempt to isolate the specific impacts that renewables penetration would have on the grid. Moreover, such a study would also clearly identify challenges to the interconnected grid that occur independent of the level of renewable development.

AWEA understands that the Commission has already begun plans for such a study, and initial scoping meetings are taking place. AWEA suggests that the Commission learn from the scope of work and analysis completed by NYSERDA. Their work focused on two phases and was intended to identify the operational and economic consequences of integrating more than 3000 MW of wind on the NYISO system.

In order to allow for a comprehensive design and adequate stakeholder input and review, AWEA suggests that the Commission authorize the following steps.

> First, hold public workshops to develop a Plan of Study that defines and refines the issues - such as those identified on February 3 -- that can be addressed in a technical simulation. If issues cannot be exposed by modeling (e.g. the cost of energy storage) authorize separate research efforts.
>
> Second, hold workshops to establish standards for consultant capability and competence.
>
> Third, use a competitive process to award the contract and engage the required work.

AWEA recognizes that a study of this nature - being comprehensive, technical and detailed -- will take months, and not weeks, to prepare, review and finalize. Indeed, the NYSERDA work was performed over the course of a year or more. Fortunately, according to the results of the CEC's own PIER funded integration study, California has the luxury of time since the report shows that the operational impacts of renewables at current penetration are negligible.

While the timeline for a year-long study may not fit conveniently within the development plan of the Commission's Integrated Energy Policy Report ("IEPR"), AWEA believes that the results of such a study are a necessary precursor to policy action.

AWEA appreciates this opportunity to comment, and would be pleased to meet with the Commission and Project staff to discuss these issues further.

Respectfully submitted,

__________/s/____________

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March 17, 2005

Commissioner John L. Geesman
Commissioner James D. Boyd
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Re: 2004-2005 Integrated Energy Policy Report 04-IEP-1F
Comments from PPM Energy

Commissioners Geesman and Boyd:

At the February 3, 2005, Committee Workshop on Transmission –Renewable Integration Issues, Docket 04-IEP-01F, PPM Energy witness James Caldwell challenged two aspects of the presentation of the Electric Power Group (EPG) and their description in the background document "Operational Issues for Integration of Renewable Generation," made on behalf of the Consortium for Electric Reliability Technology Solutions (CERTS):

1. EPG's descriptions of the WECC low voltage ride-through "standard" (LVRT) and,
2. EPG's description of the experience of E.ON Netz in Germany.

In both cases, Mr. Caldwell stated EPG's testimony "did not accurately characterize these issues" (Transcript @ p. 95).

Mr. Caldwell also stated that he would be meeting with E.ON in mid-February to discuss the report EPG relied on for its analysis, the English translation of which is entitled "Wind Report 2004." Commissioner Geesman invited Mr. Caldwell to report back to the Committee on the results of that meeting. On February 14, 2005, the CERTS team filed a memorandum in this docket further documenting these two issues and asserting that no misrepresentation of fact had occurred.

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To JIM DYER	From DON KONDOLEON
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This letter serves as an answer to the CERTS February 14 filing, and reports on the results of Mr. Caldwell's February 14 meeting with E.ON which took place at E.ON Corporate Headquarters in Dusseldorf, Germany[1].

LVRT "Standards"

The comments made by EPG at the February 3 workshop concerning the LVRT Standards contain at least two important misstatements. First, the WECC proposed LVRT standard is arguably less stringent than the standard AWEA proposed at the Federal Energy Regulatory Commission (FERC), and not as claimed by EPG, "a little bit more stringent." (Transcript @ p. 28). Second, the following statement by EPG from the February 3 Workshop mischaracterizes the reliability risk associated with wind generation:

> One impact could be if you have the AWEA standard could potentially restrict the size of the collector station at Tehachapi. From the standpoint is if you have a large cluster of wind generation that can't meet the ride-through capability of WECC, then for the right event you could lose a significant amount of generation. And that would violate the reliability. (Transcript @ p.29).

A little background is in order. For some time, the American Wind Energy Association has been speaking to the need for industry- wide "reliability standards" as applied to the interconnection of wind turbines to the nation's electricity grid. The wind industry is well aware that wind generators indeed do have electrical characteristics that are different from "conventional" generation. Grid performance and reliability standards for generator interconnection that have been developed as a body of "good utility practice" over the past century never contemplated the widespread use of multiple, relatively small, non-synchronous generators connected in parallel at generally "remote" portions of the grid. The absence of such wind generator specific standards would potentially limit the penetration of wind generators to small amounts that could be basically ignored in the context of the general response of the grid to disturbances and recovery without compromising network integrity. The common good of a reliable network is a sine qua non for which all generators, regardless of technology, share responsibility. Wind generation has no exception to this rule. Following the East Coast blackout in the summer of 2003, this issue took on some urgency, and the industry formed a Task Force that led to the filing at FERC of an AWEA proposed "Grid Code.[2]" A principal element of that "Grid Code" was a recommendation that FERC adopt as a US national standard the LVRT standard then in the process of adoption throughout the European Union known, somewhat ironically, as the "E.ON Standard." In

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[1] Mr. Caldwell met with Guido Pasternack, Vice President Electricity and Gas in the Economic and Public Affairs Department, and Erik Zizow, Leiter Energy & Technology in the Corporate Development Department. E.ON Netz is a wholly owned subsidiary of E.ON AG.

[2] "Petition for Rulemaking or, in the Alternate, Request for Clarification of Order 2003-A and a Request for Technical Conference of the American Wind Energy Association," FERC Docket No. RM02-1-001, May 20, 2004.

recommending this standard, AWEA surveyed emerging practice throughout the world, and specifically tested the efficacy of the emerging EU standard against the particular conditions on the WECC grid as well as the ability of US wind turbine manufacturers to meet that standard in a timely manner. AWEA felt that the WECC grid represented not only a significant market in its own right, but a grid whose generic characteristics would indeed require a robust LVRT standard in order to achieve "significant penetration" as has been pointed out by EPG.

Shortly after the AWEA FERC filing, the WECC Reliability Sub-Committee initiated a process to adopt an LVRT standard of its own. The Reliability Sub- Committee never published a specific voltage trace that a wind plant[3] would be required to ride-through as depicted in the "AWEA/E.ON" standard, instead deciding to concentrate on describing verbally the grid fault conditions that any generator, whether conventional fossil or wind, must endure. In the process of discussing this first draft standard last fall, the "discrepancy" between the "WECC" and the "AWEA" standard described by EPG in the background material and at the February 3 workshop emerged. Indeed, literal interpretation of the WECC language would have required that the generator ride-through a brief period at zero voltage that was "more stringent" than the AWEA standard as described by EPG. On the other hand, the WECC language requiring the generator to remain on-line through "delayed clearing" of the fault is actually "less stringent" than the AWEA standard that requires ride through at 0.15pu voltage for roughly 38 cycles ("delayed clearing" is generally understood to be a time frame significantly less than 38 cycles). Several organizations pointed out that much of the conventional generation in WECC could not meet the criteria proposed in the initial comment draft -- depending on the interpretation of the language, and that the requirement to briefly ride through all the way to zero voltage conferred little if any additional contribution to reliability.

After considering all comments from not only the wind industry, but also numerous "conventional" generation owners and Transmission Providers throughout WECC, the Reliability Sub-Committee decided to limit the required voltage depression to the 0.15pu level as in the "AWEA standard" and replace the ambiguous "delayed clearing" language by referring to WECC Table W 1 for disturbance recovery. This language was voted out of the Reliability Sub-Committee in late January, and on March 3, 2005, was voted out of the Planning Coordination Committee with a March 1, 2006 implementation date for all new generation. This "proposed standard" now goes before the full WECC Board for formal adoption in early April. Instead, EPG characterizes the issue in its February 14 filing as follows:

> At the time the workshop background material and the CERTS PowerPoint presentation were completed and sent to the CEC staff, the WECC's October 21, 2004, version was the only proposed LVRT standard posted on their site. We subsequently learnt that a

[3] The AWEA proposal applies to the voltage experienced at the Point of Interconnection of the wind "farm" with the grid, not at the wind generator terminals.

> revised version of the standard was proposed and posted on their web site on February 2, 2005, the day before the workshop. As of this date, no final standard has been adopted by WECC and what may finally get adopted may be the result of additional changes and revisions. (CERTS Feb 14, 2005 filing @p.7)

At this point in time, at least three entities which have a stake in establishing power engineering standards (WECC, FERC, and NERC[4]) are fully engaged in the LVRT issue. PPM Energy believes that the Commission can, subject to continued monitoring for implementation, consider the issue closed and move on. The inaccuracies in the "background material," the February 3 Workshop presentation, and the February 14 informational filing should be corrected for the record.

E.ON Netz Experience

Before discussing the E.ON experience, and the German, Danish, and Spanish experience in a broader context, a simple fact needs to be established. The "operating reserves" required to reliably control the Continental European UCTE grid have not changed by 1 MW with the introduction of wind energy. "Shadow generation" as the term is used in the English translation of the E.ON "Wind Report 2004" is NOT operating reserves, and the German grid does NOT carry "operating reserves," as we use the term,[5] equal to 80% of nameplate wind capacity, or 50 to 60% of nameplate wind capacity as stated variously by EPG (Transcript @ p.22). If this were true, the 19,000 MW E.ON control area alone would be carrying roughly twice the operating reserves that is carried by the entire 360,000 MW UCTE grid. The proposition that operating reserves of this level are required for reliable operation of the grid is totally inconsistent with virtually every other study of the issue. EPG could have documented the experience from Denmark and Spain – both of which have roughly 3 times the penetration level of E.ON.

In fact, "shadow generation" as used in the E.ON Report is nothing other than the complement of "capacity value." Mathematically, it is equal to (1 - ELCC). Thus an 80% shadow generation figure corresponds to the roughly 22-26% wind capacity planning value calculated by the Commission for existing wind on the California grid.[6] Given that the German wind resource is inferior to California's while the German wind turbine fleet is much more "efficient" than the almost 20-year old "first generation" California turbine fleet, the data are comparable. In

[4] A NERC "SARS" process has been initiated on this subject as well as the FERC "Notice of Proposed Rulemaking", Docket Number RM05-4, 110 FERC 61,036 (2005).
[5] The UCTE grid, representing most of Continental Europe, uses the terms "primary, secondary, and tertiary reserves" the way we use the term "operating reserves." Basically, "primary"= regulation margin + spinning reserves; "secondary" = quick start reserves; "tertiary" = replacement reserves; and "operating reserves = primary + secondary + tertiary.
[6] *California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis, Phase I: One Year Analysis of Existing Resources Results and Recommendations Final* (PIER, December 2003) at page 34.

general, there have been numerous studies that have concluded the impact of wind energy on the required operating reserves for given grids is negligible. Note that there have been two rigorous studies published in the last year in the United States that review the impact of wind integration in Minnesota and New York[7]. Neither of these studies found that wind integration threatens reliability nor requires significant operating reserves. Finally, the issue of the impact of wind on the grid operations in California has been thoroughly studied in the report prepared for the CEC and the CPUC in December 2003 under the auspices of PIER.[8]

The E.ON personnel who met with Mr. Caldwell on February 14 could not give a precise mathematical definition of the 50% to 60% of installed wind power capacity that "actually had to be used" (E.ON "Wind Report 2004" @ p.9). Further clarification was promised but has not been received as of this date. PPM will file the E.ON response if and when it is received. However, the February 14 discussion made it clear that this percentage is related to the level of "flexible generation" that E.ON redispatches to "balance" the wind within German accounting rules, not what is required from a grid operations, reliability standpoint. Considering that wind was approximately 18% of installed control area capacity during the period covered in the E.ON report, that corresponds to roughly 9-11% of the generating units whose dispatch was affected by wind energy deliveries – entirely within the capability of flexible generation that is already committed to handle diurnal load following, with or without wind on the system. In fact, no additional "flexible generation" has been required to be constructed on the German grid.

Furthermore, German control area boundaries, tariffs, and control area interchange balancing rules could hardly be more unfavorable to high wind penetration, producing significant unnecessary "costs" and requiring significant overhaul if wind integration at the level supported by German energy policy is to be achieved efficiently. The control areas are Balkanized remnants of the administrative regions set up by the Allies after World War II. There is no "spot market" in which to financially settle physical delivery imbalances – not simply lack of a formal "ISO real time market," but Germany lacks even a bi-lateral "trading hub" concept like "Palo Verde" or "Mid C" or "SP 15." Fifteen-minute schedules for control area interchange are set 17 to 39 hours in advance and there is no mechanism to financially settle deviations from these rigid advance schedules.

Thus the market structure in Germany is not conducive to intermittent generation. The integration of wind energy to the German grid must be taken in the context of their overall energy policy. Germany is in the midst of replacing much of its existing portfolio of nuclear and coal generation with renewables – principally wind. E.ON is on record as being against this

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[7] Both of these studies are referenced in the background material supplied in the EPG presentation.
[8] *California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis, Phase I: One Year Analysis of Existing Resources Results and Recommendations Final* (PIER, December 2003). See also, *California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis Phase III: Recommendations for Implementation* (PIER, July 2004).

policy. (However, note that E.ON is investing significantly in wind energy in the UK.) Wind is heavily subsidized in Germany with a "feed in tariff" equivalent to over 11 cents/kwh at today's exchange rate. E.ON, by law, pays this above market rate to wind plant owners (roughly 150,000 individuals in Germany) through over 900 local distribution companies who sell electricity at retail in Germany. E.ON is then reimbursed for the above market costs from a common nationwide pool on the basis of electricity sold. E.ON points out that it pays for roughly 45% of the wind energy but only makes 29% of the wholesale electricity sales, and, in spite of an extremely complex "redistribution formula" introduced last summer, remains under-compensated vis a vis the other German utilities. Costs that can be claimed as "integration costs" benefit utilities under the redistribution scheme. Thus, the ambivalence of E.ON towards wind energy is understandable given the structure of the tariffs.

Indeed, there may be significant lessons that California can learn from the German experience. In PPM's view, the principal lesson is that tariffs/market structure matters. Integration of non-dispatchable resources like wind under a tariff structure that emphasizes local control areas, balancing individual transactions, and physical settlements of imbalances (like Germany) will always show <u>much</u> higher costs and much lower intermittent resource penetration limits than a tariff/market structure that emphasizes regional control, system balancing, and financial settlement of imbalances (like New York). California's tariff is currently a hybrid that emphasizes regional control and financial imbalance settlements, but has a rigid balanced schedule requirement for individual "scheduling coordinators." As the California ISO implements its new market redesign that eliminates the balanced schedule requirement and attempts to set up a liquid spot market for more efficient financial imbalance settlements, wind integration costs will appear to drop significantly without any physical infrastructure changes. To reiterate, a significant portion of the costs experienced by E.ON in Germany are a reflection of poor market design rather than the result of any inherent physical problems related to the integration of wind energy into the German grid.

Germany recently completed a comprehensive study of wind integration issues related to their version of an "RPS" that calls for retirement of most of the existing nuclear and coal capacity and eventual wind penetration levels approaching 40% of energy delivered. This study was sponsored by the German equivalent of the US Department of Energy, Deutsche Energie Agentur, or DENA. The press release for this study was held on February 24, 2005. Informal English translations of the press release have been circulating on the Internet and "both sides" in the debate have been extracting snippets from the roughly 600-page filing to make their case either for or against wind. PPM Energy's preliminary read of the information contained in that report is that the findings are consistent with the perspectives outlined above, and that the conclusions regarding operating reserves, etc. hold for significantly higher wind penetration rates than are currently achieved in Germany. PPM believes that this important study needs to be placed on the record in this Docket, and, if necessary, interpreted for relevance to the California experience by knowledgeable experts familiar with both the German grid and German and US tariff structures.

In summary, PPM Energy challenges several of the underlying themes in the presentation made by the Electric Power Group at the February 3 IEPR Workshop on Transmission-Integration Issues (Docket 04-IEP-01F). Specifically, the references to the debates around the "low voltage ride through" (LVRT) standards are inappropriate given that a consensus on this topic is near at hand in a number of technical fora (WECC, FERC. and NERC). Secondly, the references to the E.ON experience in Germany imply a level of operating reserves (to use the American nomenclature) that is just not accurate.. PPM Energy looks forward to a robust process in the remainder of the 2005 IEPR to clarify these specific issues as well as advance the general discussion on this important generic subject. We believe that while refinements in our knowledge over time will improve our ability to target infrastructure investments and tariff/market structure changes to more efficiently accommodate non-dispatchable resources like wind on the California grid, that the overwhelming body of international experience clearly supports early and aggressive expansion of this low cost, zero carbon energy source.

Sincerely,

Christopher T. Ellison

Attorneys for PPM Energy

APPENDIX B
Methodology Used to Develop Estimates For Renewable Production In 2010

2010 Chronological Hourly Renewable Energy Production

The Energy Commission identified the renewable energy supply scenario that might be developed to meet estimated statewide accelerated RPS demand in the Renewable Resources Development Report.[6] Resource physical location and resource type for both energy and capacity was provided in this report (Tables 15 and 16). Total statewide additional supply to meet estimated statewide accelerated RPS renewable energy demand totaled 24,800 GWh for the period 2005 though 2010. Of this amount, 16,800 GWh[7] was identified as IOU and direct access customer requirements in the CA ISO control area.

Recorded 2004 CA ISO hourly renewable energy production profiles were used as a basis for developing the 2010 accelerated RPS hourly energy profiles based on the Energy Commission scenario. The CA ISO aggregated and provided the 2004 recorded hourly renewable production data including:

- Wind by project area for San Gorgonio, Altamont, Tehachapi, Solano, and Pacheco
- Geothermal by NP15 and SP15
- Biomass
- Solar
- Small Hydro

The CA ISO control area recorded resources for 2004 were added to the Energy Commission example to determine the mix of renewables for study in 2010. CA ISO recorded renewable production was 19,625 GWh. IOU and direct access renewable incremental demand in the CA ISO control area of 16,839 GWh for the period 2005 through 2010 was added to the recorded values to arrive at the 2010 total renewable generation of 36,464 GWh.

	CAISO Energy Mix (%)					
	2004 Recorded (GWh)	2004 Recorded (%)	2010 Acccelerated RPS (GWh)	2010 Acccelerated RPS (%)	2010 Total Renewable (GWh)	2010 Total Renewable (%)
	(a)	(b)	(c)	(d)	(a+c)	(e)
Biomass	3,261	17%	1,463	9%	4,724	13%
Geothermal	8,359	43%	3,671	22%	12,031	33%
Small Hydro	3,284	17%	0	0%	3,284	9%
Solar	708	4%	265	2%	973	3%
Wind	4,013	20%	11,440	68%	15,453	42%
Total	19,625		16,839		36,464	

Geothermal generation represents the largest source of renewable generation in 2004 or 43 percent of the total. The remaining generation is diversified among biomass, small hydro, and wind with solar representing only 4 percent of the total. The majority of CA ISO accelerated RPS resources additions come from wind and geothermal assumed to be 68 and 22 percent, respectively.

2010 Chronological Hourly Profiles

Biomass, Geothermal, and Solar

Profiles, by resource type, were calculated by multiplying the historical hourly 2004 generation values by the ratio of 2010 energy divided by 2004 recorded energy.

Small Hydro

No incremental small hydro was identified in the accelerated RPS scenario. The hourly profile recorded in 2004 was assumed to be unchanged in 2010.

Wind

2004 historical capacity factors were in the mid twenties. New RPS resource additions have a higher capacity factor of 35 percent based on Energy Commission forecast. Capacity values by service area are from AWEA.

With this change in operation scaling the hourly 2004 generation values similar to that used for the biomass, geothermal, and solar resources would be unreasonable. The installed capacity value would be exceeded to obtain the integrated energy. Limiting the 2010 hourly generation to the installed capacity results in integrate energy limitations averaging 0.7 percent.

2010 hourly wind profiles were developed by project area by taking the minimum of the 2004 hourly value multiplied by the ratio of 2010 energy divided by 2004 recorded energy times a scaling factor or the installed capacity value. Scaling factors were set to achieve the forecast integrated energy by project area.

CA ISO 2010 hourly wind data has an installed wind capacity of 5,631 MW with a maximum coincident production of 5,485 MW and an average capacity factor of 31 percent.

APPENDIX C - Generation Resource Attributes

Resource Attributes	Needed for Reliability	Needed for Operational Integration	Description of Attribute	Impact(s) of Not Providing Quantity
Energy	X	X	Ability to produce energy of a suitable quality for delivery to the grid	Inability to meet load
Fast start-up capability	X	X	The ability to meet energy and capacity needs in the short-term (minutes)	Inability to meet NERC CPS and DCS standards
Dependable Start-up capability, with predictable start-up time	X		The ability to provide replacement capacity when requested	Inability to meet NERC CPS
Ramping (Normal and Fast Capability)	X	X	The ability to adjust production (up and down) to accommodate planned and unplanned changing conditions (i.e., DCS events, scheduled interchange)	Inability to meet NERC CPS
Automatic Generation Control (AGC)	X	X	The ability to meet changing energy needs on a continuous basis very short-term (seconds)	Inability to meet NERC CPS and DCS standards
Ride Through Capability - Voltage	X		The ability to withstand a short-term	Avoid making a grid problem an

			(seconds) voltage decay without it impacting production	adequacy of supply problem.
Ride Through Capability - Frequency	X		The ability to withstand a short-term (seconds) frequency deviation without it impacting production	Avoid making a grid or interconnection problem an adequacy of supply problem. Inability to meet WECC generator performance standards for over/underfrequency performance
Short Circuit Contribution	X		Ability to contribute to the short circuit duty required to clear faulted equipment from the grid	Avoid cascading events
Predictability	X	X	Ability to accurately forecast production in the short-term (hour-ahead)	Avoid making a forecast error problem an adequacy of supply problem
Controllability	X	X	Ability to control the output of the generator to a set profile	Avoid making an individual generator control problem a grid control problem
Reliability	X		Ability to provide the desired generator characteristics	Low reliability will reduce the capacity value of a specific

			with a high degree of certainty	generator, requiring higher reserves to protect against the loss of that generator.
Voltage and VAR Support	X		Ability to maintain a voltage and VAR schedule during steady state conditions, and to provide predictable voltage support during transient conditions on the grid	Comply with WECC standard
Power System Stabilizer	X		Ability to contribute to the interconnected system dampening requirements	Comply with WECC standard
Governor Response (Droop)	X		Ability to contribute to the interconnected system frequency support requirements during transient conditions (in sub-second and second time frames)	Comply with WECC standard
Dispatchability		X	Ability to adjust production (up	Inability to meet NERC CPS and

			and down and on/off) to meet the changing conditions of load and intermittent resources	DCS
Reserves/Location	X	X	Ability to have adequate deployable resources to meet un-expected events (e.g., forced outages, high forecast errors)	Compliance with WECC MORC and inability to meet NERC CPS and DCS standards
Resource Location	**X**	**X**	**Ability to have generating resources strategically located to mitigate grid problems and to reduce transmission infrastructure costs**	Potential for stranded load or generation pockets under certain conditions and higher transmission infrastructure costs

End Notes

[1] American Wind Energy Association's comments submitted by Mike Jacobs, Acting Policy Director; California Wind Energy Association's comments submitted by Nancy Radar, Executive Director; PPM Energy's comments submitted by Christopher T. Ellison, Attorney for PPM Energy; Southern California Edison's comments submitted by Gary Schoonyan, Director San Francisco Office.

[2] California Energy Commission. *California RPS Integration Cost Analysis – Phase 1: One Year Analysis of Existing Resources. Publication No. 500-03-108C. December 2003. http://www.energy.ca.gov/reports/2004-02-05_500-03-108C.PDF - 4835.*

GE Energy, Energy Consulting. Prepared for the New York State Energy Research and Development Authority. *The Effects of Integration Wind Power on Transmission System Planning, Reliability and Operations – Report on Phase : System Performance Evaluation.* March 4, 2005.

Hirst, Eric. Prepared for Power Business Line; Bonneville Power Administration. *Integrating Wind Energy with BPA Power System: Preliminary Study.* September 2002

[3] California Wind Energy Collaborative. Prepared for the California Energy Commission. Public Interest Energy Research. *California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis. Phase III: Recommendations for Implementation*. Publication No. P500-04-054. July 2004.

4 Development of the 2010 forecast hourly renewable generation is discussed in Appendix B.

[5] CDWR-CERS contract portfolio begins to drop off significantly starting in 2010. Contract renegotiations impacting the portfolio prior to 2010 could improve operating flexibility.

[6] California Energy Commission. *Renewable Resources Development Report.* Publication No. 500-03-080F. November 2003.

[7] California Energy Commission. *Accelerated Renewable Energy Development. Draft Staff White Paper*. Publication No. 100-04-003D. July 30, 2004.