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INTERMITTENCY ANALYSIS PROJECT:

FINAL REPORT

PIER PROJECT FINAL REPORT

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Intermittency Analysis Project Team

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

The Intermittency Analysis Project: Summary of Final Results is a final report by the Intermittency Analysis Project team performed under a work authorization (MR-017) through the California Wind Energy Collaborative (CWEC) at the University of California, Davis. The information from this project contributes to PIER's Renewable Energy Technologies Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-5164.

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Abstract

The California Energy Commission's Public Interest Energy Research Program assembled an industry team to tackle the challenges of integrating renewables into a future 2020 electricity transmission system. The Intermittency Analysis Project conducted a series of scenario-based studies to examine the statewide system impacts of higher levels of intermittent renewables on the California electricity and transmission infrastructure. Based on the analysis, technical and operational strategies and mitigation measures are recommended for consideration by California's utilities and system integrator. The analysis also provides a framework for system operators, utilities, and infrastructure planners to gauge the needs of the future 2020 system. Working with various agencies and California utilities to ensure coordination and to review results and findings, the Intermittency Analysis Project team also incorporated recent findings and input from a number of regional study groups in California, as well as lessons learned from the international perspective. Results include providing a detailed technical analysis of existing and future infrastructure needs, addressing potential operational strategies, developing a set of utility "best practices," and tools for integrating intermittent renewables, and as problems were encountered, assessing potential mitigation options to ensure sustainable operation.

This final project report summarizes the results and recommendations of a series of reports and presentations produced by the project team. All reports and presentations are available on the Energy Commission website (www.energy.ca.gov).

Keywords: Aggregate megawatt contingency overload, intermittency analysis, renewable integration, remedial action schemes, renewable portfolio standards, renewable transmission benefit ratio, transmission impacts, wind energy, solar energy

Executive Summary

Introduction

This report serves as the final project report for the Intermittency Analysis Project. The Intermittency Analysis Project was organized to

1. Consider the impacts on the electricity grid of higher levels of intermittent renewables from a scenario basis;
2. Trace the historical evolution of wind technologies in California and their changing impact on the grid;
3. Determine how other international regions have integrated intermittent renewables generation.

The Intermittency Analysis Project team produced five major reports, and the project resulted in recommendations for California to successfully integrate higher levels of variable renewable energy generation per state energy policy targets, which are discussed in this final report and associated appendices.

Purpose

The Intermittency Analysis Project is a comprehensive project aimed at addressing multiple aspects of the potential impact of more intermittent renewables. The project team, through transmission load flows, statistical analysis, and production cost modeling, examined the statewide impacts of more intermittent renewables on the California electricity and transmission infrastructure. These higher levels are in response to meeting the Renewables Portfolio Standard of 20 percent renewable energy by 2010 and the accelerated target of 33 percent renewable energy by 2020. The project quantified impacts on the grid as a result of increasing renewable penetration by analyzing transmission infrastructure needs as well as operational flexibility though a series of scenarios. Mitigation options as well as operational response strategies were demonstrated using production cost modeling and load-flow simulation tools. The results and recommendations based on the statewide analysis provide a framework for system operators, utilities, and infrastructure planners to gauge transmission and future grid needs for their service areas and the region as more renewable energy generation is installed in California.

The Intermittency Analysis Project assessed the following four scenarios considering renewables within California:

- 2006 Base – Baseline for the existing California grid.
- 2010T – 2010 Tehachapi case with 20 percent renewables and 3,000 megawatts (MW) of new wind capacity at Tehachapi.

- 2010X – 2010 accelerated case planning toward 33 percent renewables.
- 2020 – 2020 case with 33 percent renewables.

The effort resulted in seven reports and various presentations for two public workshops. All reports and presentation material along with study datasets are available from the Energy Commission's website (www.energy.ca.gov).

BEW Engineering was commissioned to produce a report on the historical evolution of wind turbine technology in California, while Exeter Associates, Inc., prepared a report on the international experience with integrating variable renewable energy generation. AWS TrueWind prepared the wind profiles and wind forecasts; Davis Power Consultants compiled the renewable resource mixes, load flows, and transmission expansion build-out for the four scenarios; and General Electric Energy Consulting conducted statistical analysis, quasi-steady-state simulations, and production cost modeling.

The Davis Power Consultants' and General Electric Energy Consulting reports are included as part of the Intermittency Analysis Project Final Report. The analysis and results of both reports are interdependent and should be viewed as such. Davis Power Consultants prepared the renewable resource mixes and the load flows for the four assessed scenarios, and their efforts provided an illustration of the "future grid" that could accommodate more intermittent renewable energy generation. General Electric Energy Consulting, in turn, relied upon the renewable resource mixes, transmission infrastructure, and the load flows to conduct statistical analysis and production simulation analysis of the potential effects of intermittent renewable energy generation on operations and scheduling.

By conducting power flow and production cost simulations, the Intermittency Analysis Project team, with the Intermittency Analysis Project industry advisory team, established a 2006 baseline and renewable resource portfolios and infrastructure for 2010 and 2020 study cases. Load flows were prepared using PowerWorld software. Production costs were modeled using General Electric's Multi-Area Production Simulation™ modeling software to evaluate grid operation with increasing levels of wind and solar generation in the generation mix. All datasets were prepared with utility stakeholders and will be provided to the Western Electricity Coordinating Council and utilities for ongoing study needs.

Project Objectives

The Intermittency Analysis Project focuses on five objectives:

1. Statewide transmission options to integrate in-state renewables to meet policy targets;
2. Identifying the positive and negative quantitative effects of various options on transmission reliability, congestion, and mix of renewable technologies;

3. Developing the tools and analysis methods to evaluate renewables along with conventional generation;
4. Providing a common perspective for evaluating different technologies competing for limited system resources, and
5. Providing a common forum for commissions, utilities, and developers to examine the location and timing of new generation/transmission projects and the public benefits of these resources.

Project Outcomes and Conclusions

California can incorporate the amount of renewables based on the Intermittency Analysis Project scenarios, provided appropriate infrastructure, technology, and policies are in place. Specifically, this successful integration will require:

- Investment in transmission, generation, and operations infrastructure to support the renewable additions.
- Appropriate changes in operations practice, policy and market structure.
- Cooperation among all participants, for example, the California Independent System Operator, investor-owned utilities, renewable generation developers and owners, non-Federal Energy Regulatory Commission jurisdictional power suppliers, and regulatory bodies.

Numerous findings and recommendations are discussed in further detail in each of these project-related reports.

1. *Impact on Past, Present and Future Wind Turbine Technologies on California Grid* by BEW Engineering, CEC 500-2006-050, May 2006.

   BEW reviewed past, present, and future wind turbine technologies in terms of performance and grid impact. State-of-the-art technologies are becoming more grid-friendly and incorporate advance power electronics for added electrical control during intermittent periods.

2. *Intermittency Analysis Project: Characterizing New Wind Resources in California*, by AWS TrueWind LLC, CEC 500-2007-014, March 2007.

   AWS Truewind provided wind energy forecasts in geographically diverse areas in the state and simulated generation data to support the California Energy Commission's Intermittency Analysis Project. An objective of the Intermittency Analysis Project is to assess the effects of a substantial expansion of wind generation on the reliability, operation, and economic performance of the California Bulk Power System. At the same time, the forecasts and generation took into account performance of new wind turbine technologies tailored for operation in varying wind regimes. The scenarios of wind generation include more than 10 gigawatts

(GW) of new wind production capacity, in addition to the existing capacity, of approximately 2 GW. AWS Truewind's role was to:

- Identify and characterize a number of sites for prospective new wind energy projects to satisfy the expansion scenarios in 11 focus areas of the state.
- Simulate three years of hourly wind generation from both the existing and proposed new wind plants using power curves representative of current and future wind turbines.
- Simulate next-day hourly wind generation forecasts for the same plants.
- Produce samples of one-minute output data for significant or representative times.

These data were used by General Electric Energy Consulting to assess the effects of wind generation on various aspects of the California Bulk Power System's operations and costs. This report describes the methods, assumptions, and results of AWS Truewind's analysis.

3. *Summary of Preliminary Results for the 2006 Base and 2010 Tehachapi Cases* by Intermittency Analysis Project Team, CEC 500-2007-009, February 2007.

   This interim report focuses on the assessment methods, scenarios, and explanation of assumptions and highlights some of the preliminary findings presented at a Commission staff workshop on August 15, 2006.

4. *Review of International Experience Integrating Variable Renewable Energy Generation* by Exeter Associates Inc., CEC 500-2007-029, April 2007.

   This report summarizes the experience in the United States and internationally through 2006 with integrating variable renewable energy generation, primarily wind generation, and discusses potential operating and mitigation strategies for incorporating variable renewable energy generation. Initially, wind development in Europe, particularly in Denmark and Germany, consisted of smaller but numerous wind projects interconnected to the distribution grid, in contrast with larger, utility-scale wind projects interconnected to the transmission grid in the United States. The differences between Europe and the United States are starting to narrow as development of variable renewable energy generation (for example, wind and solar) increases and as wind development takes place in more countries. In addition, as more utility-scale wind projects emerge, more countries are relying on common strategies, such as grid codes, to help integrate variable renewable energy generation. A review of the international experience provides perspective and insight to the Intermittency Analysis Project analysis team on various techniques for

managing intermittency. Detailed country profiles are also provided for Germany, Denmark, India, and Spain.

5. *Intermittency Impacts of Wind and Solar Resources on Transmission Reliability* by Davis Power Consultants.
6. *Intermittency Analysis Project* by General Electric Energy Consulting.
7. *Intermittency Analysis Project: Final Report* by Intermittency Analysis Project Team.

Reports 5 and 6 are contained in this Final Report as Appendices A and B. This report is Report 7. Highlights of the transmission expansion study by Davis Power Consultants and the operational impact study by General Electric Energy Consulting are provided below. Findings are recommendations are organized and presented in three topical areas: Generation Resource Adequacy, Transmission Infrastructure, and Renewable Generation Technology, Policy and Practice.

Generation Resource Adequacy

- A combination of in-state generating resources and power exchange agreements or capability should be pursued to allow operation to a minimum net load of between 18,000 to 20,000 MW.
- Pursuing generating resources with greater minimum turndown and diurnal start/stop capabilities, ensuring greater participation by loads, and optimizing use of pumped storage hydro will also aid with integrating variable renewable energy generation.
- In-state generating resources should also be targeted for providing scheduling flexibility hourly. For light load conditions, total hourly scheduling flexibility requirements are smaller, but the relative impact of variable renewables is greater. Maintaining or improving hydro flexibility and accessing generating resources with faster start and stop capabilities will aid with hourly scheduling flexibility.
- For sustained, multi-hourly load increases and decreases, the California grid should have the capability to meet a maximum morning load increase of 12,000 MW over three hours and a maximum evening load decrease of 14,000 MW over three hours.
- An increase of 10 MW/minute of load following is necessary to incorporate the levels of renewables studied as compared to the requirements for load alone. About 70 MW/minute of down load-following requirements is necessary during light load periods.
- California should consider allowing import and export scheduling to occur more frequently and at other times than on the hour.
- The effect of variable renewables on regulation is relatively modest (20 MW). Still, California should, at least, maintain current level of regulation capability and

consider other means of providing regulation besides conventional generation, such as flywheels or variable speed pumped hydro.

- While operational flexibility is valuable to the grid, it can impose significant costs and revenue reductions on generation providers. Expanded ancillary service markets, incentives, and requirements may be necessary to overcome this problem.
- The Intermittency Analysis Project analysis did not include historical constraints such as long-term contractual obligations. New proposed contracts and existing long-term contracts up for renewal or subject to renegotiation should be reviewed to increase grid flexibility and adequacy.
- Increased competition from new resources, renewables or otherwise, may push marginally profitable generating resources out of business. Plant retirements should be projected, monitored, and evaluated.
- California should measure, verify, and catalogue the flexibility characteristics of individual generating resources.

Transmission Infrastructure

- Transmission planning to accommodate multiple wind plants should consider the spatial diversity of these plants. Wind plants close together will typically require transmission capability to the aggregate rating of the plants, while wind plants further apart may require less transmission capability.
- Significant transmission investments are necessary to meet the 2010 and 2020 renewable targets. For the 2010 Tehachapi case, 74 new or upgraded transmission line segments are needed at a first-order estimated cost of $1.2 billion. Most of these line segments (63) are needed to serve growing load. In addition, 31 new or improved transformers would be needed for an additional cost of $161 million (excluding detailed land use and right of way costs).
- The 2020 case would require 128 new or upgraded transmission line segments, with just over half (66) needed to serve increasing load requirements. For just the 500-kilovolt (kV) and 230-kV additions, a first-order estimated cost would be $5.7 billion. In addition, 40 new or improved transformers would be needed at an estimated cost of $655 million (excluding detailed land use and right-of-way costs).
- The transmission analysis suggests that wind variability may contribute to transmission congestion under certain renewable energy dispatch scenarios, and that transmission congestion patterns are more difficult to predict as the penetration of variable renewable energy resources increases.

Renewable Generation Technology, Policy, and Practice

- Policy and regulatory and contractual practices to maximize existing use of transmission should be encouraged, such as real-time line ratings, local short-term forecasting, and controls that manage output from multiple variable renewable energy resources.
- Under rare circumstances of coincident minimum load, high wind generation, and low conventional hydro flexibility, curtailment of variable renewable energy generation may be necessary.
- Regulatory and contractual arrangements for intermittent renewables should be designed to allow and compensate for the provision of ancillary services such as frequency regulation.
- Wind and solar forecasting offers significant benefits in the multi-day, unit commitment, and short-term (hours and minutes) time frames. Through policy or investment, high fidelity forecasting for all variable renewable energy generation in California should be conducted.

Recommendations

This project provides a piece of the larger transmission planning and system operations picture. As renewable penetration levels increase, continuing timely and routine long-term planning and analysis of the statewide system as well as local system by utilities is needed to determine the existence of and the magnitude of potential problems. Technology, policy, and the environment (market and infrastructure) need to be assessed holistically with periodic reassessments using complete and quality data. As much as possible, experiences, data, and results from this effort should be leveraged for other state, multi-state, and western region studies. The Intermittency Analysis Project as designed is limited to the in-state renewable resource perspective, defined technical scope, and a number of assumptions defined by the scenario analysis. For a more complete description of the scenario assumption, see *Summary of Preliminary Results for the 2006 Base and 2010 Tehachapi Cases* by Intermittency Analysis Project Team, CEC 500-2007-009, February 2007. It is recognized that the portfolio implemented in the future will be a balance of in-state and out-of-state resources, thus defining in actual impacts on the grid. This feasibility analysis identifies some of the issues seen from a statewide integrated perspective using in-state renewables. However, it is limited in resolution and data. The results and findings supplement and support continuing transmission and renewable integration studies being conducted by the California Independent System Operator, the California Public Utilities Commission, and the utilities.

Benefits to California

The Intermittency Analysis Project should provide significant information, recommendations, and benefits in support of attaining the state's accelerated Renewables Portfolio Standard targets. These include:

1. A vision of the "*in-state* future transmission grid" (infrastructure and operating services) and the mix of renewable resources (wind, solar, geothermal, biomass) needed to accommodate the Renewables Portfolio Standard penetration levels.
2. Recommendations for a portfolio of renewable resources to meet the 20 percent Renewables Portfolio Standard target by 2010 and the 33 percent goal by 2020.
3. Unified transmission infrastructure solutions and intermittency mitigation measures that transcend utility service boundaries to achieve an economically robust and reliable grid.
4. Quantified system performance and results based on the "future grid solutions" that can later be converted into integration cost adders.
5. Integrated transmission expertise from various California utilities, industries, state agencies, and consultants to form a consolidated statewide system of solutions, mitigation measures, and intermittency management strategies.
6. Delineation of the physical transmission limits from policy and contract limits to push intermittent renewable resource penetration levels and to provide future market structure recommendations.
7. Estimates on emission benefits for the state based on study scenarios for oxides of sulfur (SO_x), oxides of nitrogen (NO_x), and carbon dioxide (CO_2).
8. Identification of the technology, policy, and market gaps that may be barriers to meeting Renewables Portfolio Standard goals.

1.0 Introduction

California has one of the most diverse electricity supply systems in the nation with a large potential to generate electricity from renewable sources, such as wind, geothermal, biomass, hydroelectric and solar. With renewable energy policies such as the Renewables Portfolio Standard (RPS) and the *2005 Energy Action Plan II*, the challenge facing the state will be how best to integrate and manage renewable energy resources with traditional generation while ensuring a reliable electricity system.

The California RPS requires investor owned utilities to have 20% of its generation from renewable energy by 2010. In addition, the State Energy Action Plan has set a state goal of 33% renewable energy by 2020. A few of the main challenges facing the state in trying to achieve these targets include:

- Building sufficient transmission infrastructure to support and sustain the renewable energy development envisioned for 2020.
- Balancing the need to integrate increasing levels of renewable energy while minimizing adverse impacts on the surrounding environment.
- Developing tools with the industry to properly integrate variable renewable resources including wind and solar while maintaining grid reliability.

The Intermittency Analysis Project (IAP) is tailored to present a statewide perspective for the transmission infrastructure and services needed to accommodate the renewable penetration levels defined in the state's renewable energy policy. The IAP is technical in nature and is intended to provide a future perspective through 2020 on the potential operational needs and impacts to meet future growth and demand. As a result, certain assumptions on technology availability, system conditions and constraints, as well as market constraints have to be made.

Questions that the IAP seeks to address include:

- What are the impacts of increasing levels of renewable energy generation on system reliability and dispatchability, with a particular focus on wind and solar energy?
- What will the future system look like and where will the resources come from?
- How will the future grid need to respond (i.e. market structure, services, and technologies)?

In this project, power flow and production cost modeling are conducted, first, to establish the operational baseline of the California grid as of 2006 and then second, to develop the renewable resource mixes for the 2010 and 2020 scenarios emphasizing in-state resources. Renewable portfolio mixes, as well as the transmission needed to interconnect the resources will be evaluated in the scenarios based on a transmission benefit criteria. The modeling builds and expands on previous Commission funded transmission studies that focused on connecting statewide renewable resource potential and transmission considerations.

The IAP effort leverages work conducted by the California Wind Energy Collaborative (CWEC) *RPS Renewable Generation Integration Cost Analysis Multi-year Report*, the Consortium for Electric Reliability Technology Solutions (CERTS) *Assessment of Reliability and Operational Issues for Integration of Renewable Generation*, and the *Strategic Value Analysis (SVA) for Integrating Renewable Technologies in Meeting Target Renewable Penetration* work by Davis Power Consultants (DPC). Under the SVA project, the Public Interest Energy Research (PIER) program and DPC assessed the availability of renewable resources and defined an approach that minimizes transmission infrastructure changes and maximizes benefits for integrating renewables onto the California grid by avoiding congestion. Availability of inter-and intra-state renewable resources and transmission requirements were also modeled using the SVA approach to alleviate, or at least minimize, transmission constraints. Details on state energy policy and referenced project efforts can be found on the Commission website (www.energy.ca.gov).

In addition to this project report, the IAP project produced a number of reports and presentations for two public informational workshops. The reports are as follows:

1. ***Impact on Past, Present and Future Wind Turbine Technologies on California Grid*** **BEW Engineering, CEC 500-2006-050, May 2006**

   This document describes the evolution of utility-scale wind turbine technology and wind plant development over the past 25 years with an emphasis on the electrical impacts related to performance, reliability, power quality and operation of the interconnected transmission network. The electrical characteristics of modern-day wind turbines and the impact of those characteristics on electric power transmission system planning and operation are emphasized. The target audience is the engineer with some basic familiarity with electric power systems and the transmission planning process, but with little or no background in wind energy conversion technology and its impact on the grid. Prior California Energy Commission (Energy Commission) and CWEC reports have provided technical background on the aerodynamic and mechanical aspects of modern wind turbines, including the turbine rotor (blades) and drive train, up to and including the gearbox. This report expands upon that body of work by focusing on the electromechanical conversion of wind energy to electrical energy, from the gearbox output shaft all the way to the bulk power transmission network. The scope of this document is limited to utility scale wind plants with interconnections at the high voltage transmission level.

2. ***Intermittency Analysis Project: Characterizing New Wind Resources in California*****, by AWS TrueWind LLC, CEC 500-2007-014, March 2007**

   AWS Truewind provided certain wind energy forecasts and data in support of the Energy Commission's IAP. The objective of the IAP is to assess the impacts of a substantial expansion of wind generation on the reliability, operation, and economic performance of the California Bulk Power System (CABPS). The scenarios of wind

generation include over 10 gigawatts (GW) of new wind production capacity, in addition to the existing capacity, which totals about 2 GW. AWS Truewind's role was to:

- Identify and characterize a number of sites for prospective new wind energy projects sufficient to satisfy the expansion scenarios in 11 focus areas of the state;
- Simulate three years of hourly wind generation from both the existing and proposed new wind plants;
- Simulate next day hourly wind generation forecasts for the same plants, and
- Produce samples of one minute output data for significant or representative times.

These data were used by General Electric Energy Consulting (GE) to assess the impacts of wind generation on various aspects of the CABPS's operations and costs. This report describes the methods, assumptions, and results of AWS Truewind's analysis.

3. ***Summary of Preliminary Results for the 2006 Base and 2010 Tehachapi Cases* by Intermittency Analysis Project Team, CEC 500-2007-009, February 2007**

This interim report focuses on the assessment methodology, scenarios, explanation of assumptions, and highlights some of the preliminary findings presented at a Commission staff workshop on August 15, 2006.

4. ***Review of International Experience Integrating Variable Renewable Energy Generation* by Exeter Associates Inc., CEC 500-2007-029, April 2007**

This report summarizes the experience in the United States and internationally through 2006 with integrating variable renewable energy generation, primarily wind generation, and discusses potential operating and mitigation strategies for incorporating variable renewable energy generation. Initially, wind development in Europe, particularly in Denmark and Germany, consisted of smaller but numerous wind projects interconnected to the distribution grid, in contrast with larger, utility-scale wind projects interconnected to the transmission grid in the United States. The differences between Europe and the United States are starting to narrow as development of variable renewable energy generation (e.g. wind and solar) increases and as wind development takes place in more countries. In addition, as more utility-scale wind projects emerge, more countries are relying on common strategies, such as grid codes, to help integrate variable renewable energy generation. A review of the international experience provides perspective and insight to the IAP analysis

team on various techniques for managing intermittency. Detailed country profiles are also provided for Germany, Denmark, India and Spain.

5. ***Intermittency Impacts of Wind and Solar Resources on Transmission Reliability*** **by Davis Power Consultants**
6. ***Intermittency Analysis Project*** **by GE Energy Consulting**
7. ***Intermittency Analysis Project: Final Report*** **by Intermittency Analysis Project Team**

All reports and public workshop presentations are available from the Energy Commission's web site. The DPC and GE reports are released as part of the Final Report. The analysis and results are interdependent and should be viewed as such. DPC prepared the renewable resource mixes and the load flows for the four scenarios, and their report provides an illustration of the "future grid" that could accommodate higher levels of intermittent renewable energy generation. GE, in turn, relied upon the renewable resource mixes and the load flows to conduct statistical analysis and production simulation analysis of the potential impacts of intermittent renewable energy generation.

The IAP project addressed four renewable resource scenarios with varying amounts of wind and solar:

- ***2006 Base*** – Baseline for the existing California grid
- ***2010T*** – 2010 Tehachapi case with 20% renewables and 3,000 megawatts (MW) of new wind capacity at Tehachapi
- ***2010X*** – 2010 accelerated case planning toward 33% renewables
- ***2020*** – 2020 case with 33% renewables

The materials in this report focus on the *Intermittency Analysis Project* assessment methodology, the renewable resource scenarios that were developed and of the findings and recommendations contained in the DPC and GE reports.

The IAP as designed is limited to the in-state renewable resource perspective, defined technical scope and a number of assumptions defined by the scenario analysis For a more complete description of the scenario assumption, see *Summary of Preliminary Results for the 2006 Base and 2010 Tehachapi Cases* by Intermittency Analysis Project Team, CEC 500-2007-009, February 2007. It is recognized that the portfolio implemented in the future will be a balance of in-state and out-of-state resources thus defining in actual impacts on the grid. This feasibility analysis identifies some of the issues seen from a statewide, integrated perspective using instate renewables, however is limited in resolution and data. The results and findings supplement and support continuing transmission and renewable integration studies being conducted by the California Independent System Operator (California ISO), the California Public Utilities Commission (CPUC) and the utilities.

2.0 Analysis Methodology and Project Approach

2.1 Renewable Resource Potential and Availability

The IAP incorporates previous work which identified in-state renewable resource locations and availability. Renewable resources included in the IAP portfolios were evaluated for both "locational" and "temporal" benefits in relation to transmission and used a basic approach developed as part of the *Strategic Value Analysis for Integrating Renewable Technologies in Meeting Target Renewable Penetration* (Figure 2-1). The process steps include:

1. Review renewable resource assessments for the state to generate a set of gross and technical resource potential and their locations for each renewable type. These assessments are included in *California Wind Resources* and in the *Renewable Resources Development Report.*
2. Conduct transmission impact analysis for the system.
3. Apply economic filters such as current costs of energy and type of technology to reduce the technical resource potential to an economic potential, as contained in *Strategic Value Analysis – Economics of Wind Energy in California*.
4. Refine economic potential by combining it with a transmission impact analysis as described in *Draft Report on 2010 and 2017 Weighted Transmission Loading Relief Factor (WTLR)*.
5. Evaluate and prioritize resource areas for the most significant impact on alleviating congestion on the electrical grid within a certain timeframe (i.e. to meet 2010 or 2020 goals) as well as other non-energy economic drivers/benefits such as jobs and reduction of pollutants.
6. Integrate all resources into a combined analysis to include all renewables assessed as described in *Strategic Value Analysis for Integrating Renewable Technologies in Meeting Target Renewable Penetration*.

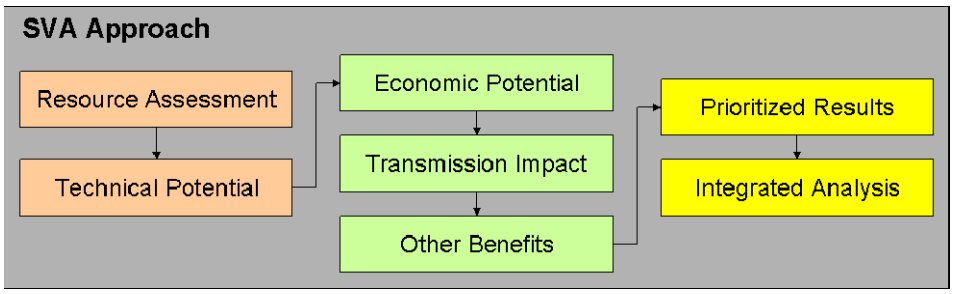


Figure 2-1. Renewable resource and transmission integrated analysis approach

2.2 Data Sources

Data from a variety of sources are used to construct the California statewide transmission dataset for the future scenarios as summarized in Table 2-1.

The load data was scaled for 2006 and 2010 conditions by the ratio of peak loads based on historical years, 2002 through 2004. Hourly load data, both forecasted and actual, came from the California ISO) for 2002 through 2004. The California ISO also provided load data in megawatts sampled at 4-second intervals for 400 days in the same three-year analysis period. California ISO also provided historical operations data for hydroelectric generation and Department of Water Resources (DWR) pump loads for 2004 and 2006, and confidential ramp rate data for individual generating units.

Table 2-1. IAP data and resources for transmission models

Data Description	Source
• Hourly load (forecasted & actual) for 2002–2004 • 4-second load (MW) data samples for 400 days during the 2002-2004 period • Historical operations data for hydro and DWR pumped loads for 2004 and 2006	California ISO
• Wind data (forecasted & actual) • 1-minute MW data for wind in 51 selected time periods for existing and new potential wind sites in CA	AWS Truewind – modeled data
• Historical solar insolation database • Hourly solar insolation measurements & satellite assessed data • Hourly solar generation for new resource potential in Mojave areas • 1-minute solar insolation variability data for select locations	National Renewable Energy Laboratory, Stirling Energy Systems, State University at Albany
• Hourly and 15-minute photovoltaic generation data for 2004 aggregated by zip code	California Public Utilities Commission-Self Generation Incentive Program
• Historical hourly and 1-minute generation data for existing renewable facilities from 2002-2004; • OASIS database	California Wind Energy Collaborative, California ISO

OASIS = Open Access Same-Time Information System

AWS TrueWind provided wind data for the 2002–2004 period, covering hourly wind MW (forecast and actual) and 1-minute wind MW data for 51 selected time periods for a large number of existing and future wind plant sites in California. Focus areas for future wind resources in California identified for this study are shown in Figure 2-2.

Solar data was assembled from a variety of sources. Hourly and 1-minute generation data for the Sungen and Luz facilities from 2002 through 2004 was provided by the California ISO and CWEC. Using historical insolation data from 2002 to 2004 provided by the National Renewable Energy Laboratory (NREL), Stirling Energy Systems produced hourly solar MW data for potential sites near Mojave. The California Public Utility Commission's (CPUC) Self-Generation Incentive Program (SGIP), administered by Southern California Edison (SCE), supplied hourly and 15-minute photovoltaic (PV) generation data for 2004,

aggregated by zip code. Onsite data also came from a number of local projects throughout California. To account for sub-hourly variability in solar data, the Atmospheric Sciences Research Center at the State University at Albany provided 1-minute and 3-minute solar insolation data at two representative locations for the months of January and July 2002. Using this data, representative solar profiles were complied for multiple sites throughout California.

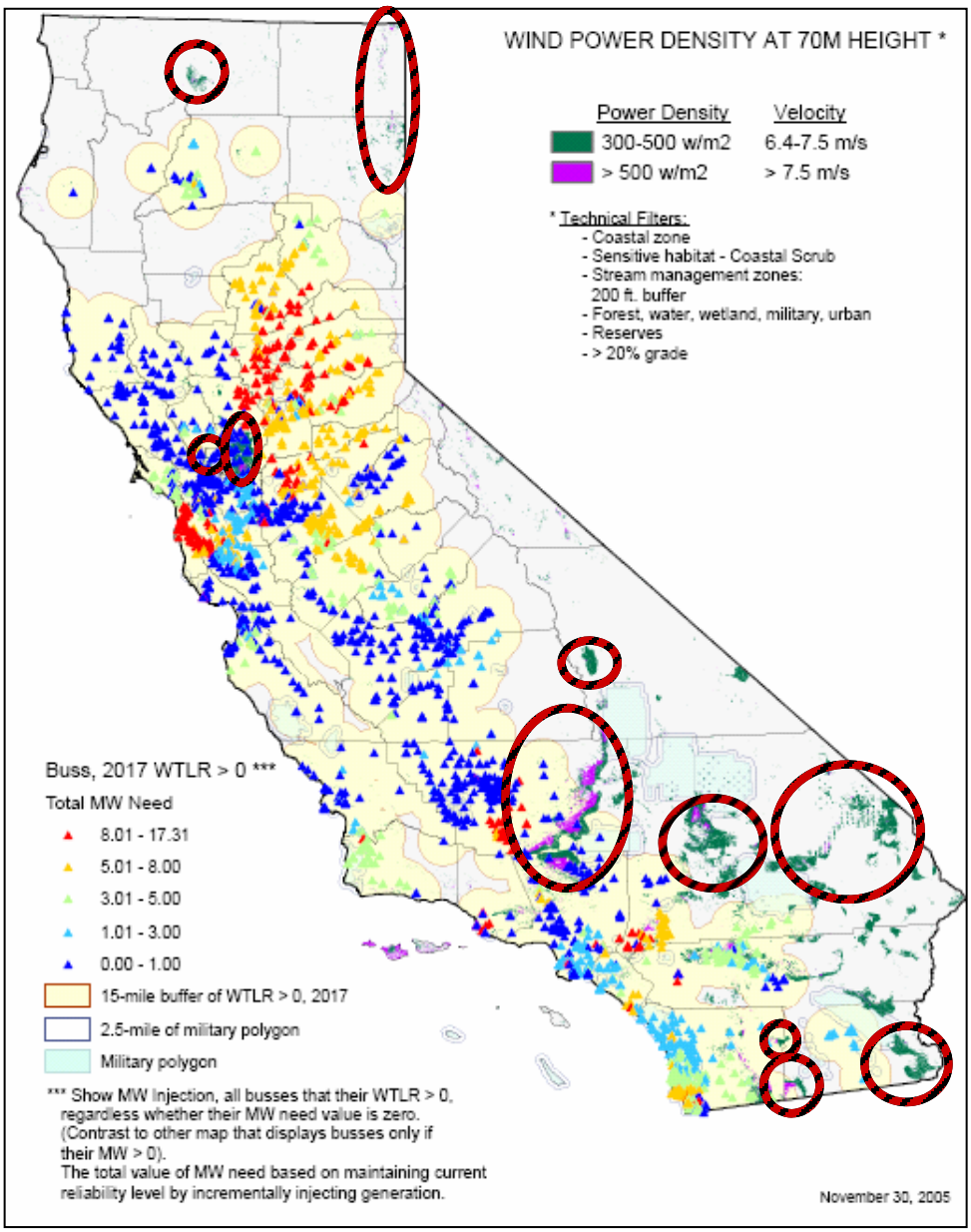


Figure 2-2. Focus areas for future wind sites

w/m2 = watts per square meter; m/s = meters/second

Historical load, wind, and solar MW are thus related and correspond to time of day and weather. The load data from each of the 2002 through 2004 historical years is scaled to match the projected peak load for 2006, 2010 and 2020 target years. As a result, for the

analysis of each scenario, all three years versus only one year of historical performance data is used to account for variations from year to year. For example, for the 2010 Tehachapi case, the three years of data generated include:

- 2010 peak load using 2002 load, wind, and solar profiles
- 2010 peak load using 2003 load, wind, and solar profiles
- 2010 peak load using 2004 load, wind, and solar profiles

2.3 Transmission Assessment

Potential transmission impacts due to deploying new renewable resources are assessed using a transmission reliability metric developed by the DPC team which includes Davis Power Consultants, PowerWorld and Anthony Engineering. This metric is called the Aggregated Megawatt Contingency Overload (AMWCO).

The AWMCO metric is based on standard reliability measures from the North American Electric Reliability Council (NERC) "N-1" contingency approach. This "N-1" approach examines the impact that the loss of a generator, transmission line or substation has on the reliability of the electricity system. The AWMCO is a relative measure and is defined as the weighted sum of the number of overloads and the percentage the lines are overloaded. The larger the AWMCO value, the weaker is the transmission element. The AMWCO for the California grid can be measured by summing over all transmission elements. Using this contingency approach and incorporating forecasted load growth, expected new generation and transmission capacity, a forecast of potential overload situations or "hot spots" can be determined for various analysis years.

The DPC team created factors to prioritize generation source locations and compare transmission benefits. First, areas where transmission is relatively weak were identified and correlated to potential renewables locations. "Hot spots" are then determined by running a series of contingency analyses which look at over 5000 transmission lines, transformers and power plants in the state. Using PowerWorld, power flow simulations were conducted that applied the AMWCO approach to compare and to prioritize locations for adding new power plants (renewable as well as conventional generation) which would alleviate congestion and provide a net benefit to the grid.

The AMWCO is used to determine the Renewable Transmission Benefit Ratio (RTBR). The RTBR is the difference in AMWCO between the renewables case and base case, divided by the total added renewables. The more negative the RTBR, the more the transmission reliability is improved by the addition of renewable energy capacity at that particular location. The RTBR is expressed by the equation:

$$RTBR = \frac{AMWCO_{renewables} - AMWCO_{base}}{\sum MW_{renewables}}$$

where:

- $AMWCO_{base}$: Base Case [MW]

- $AMWCO_{renewables}$: system with new installed renewables [MW]
- $MW_{renewables}$: additional renewable capacity [MW]

An RTBR < 0 indicates improved transmission system reliability.

The results of a number of transmission impact analyses are then combined with all renewable resources studied (wind, geothermal, biomass, solar) to arrive at the final integrated statewide portfolio mix. Results include:

- Generation mixes for scenario analysis specifying capacity in MW, generator type and location.
- Prioritized resource areas by location and benefit to transmission.
- Recommendations for potential transmission upgrades and new transmission needs.
- Estimated transmission implementation cost projections (does not include right of way or land use costs).
- Levelized cost of energy projections for 2006, 2010, and 2020.

Based on the transmission load flow modeling, renewable resource portfolios containing a mix of renewables are developed for each of the scenarios identified under the IAP. Four renewable resource scenarios are evaluated under the project. Each scenario has varying amounts of wind and solar which meet policy targets. The scenarios are:

1. 2006 Base case.
2. 2010 Tehachapi case with 20% renewables and 3,000 MW of wind at Tehachapi.
3. 2010 Accelerated case planning toward 33% renewables.
4. 2020 33% Renewables case.

The 2006 case represents the operational baseline for the California grid and consists of 2005 information scaled to 2006. The 2006 Base case represents the operational baseline for the existing California grid. The 2010 Tehachapi case, also known as 2010T, targets the inclusion of 3,000 MW of wind capacity in the Tehachapi region of southeastern California and is designed to test for potential grid impacts given a large concentration of wind resources in a particular region. The 2010 Accelerated case also known as 2010X, serves as a sensitivity case for planning toward 33 percent renewable energy penetration. The 2020 case provides a perspective on a 33 percent renewable portfolio mix and the necessary accompanying transmission infrastructure. Table 2-2 summarizes the non-hydro renewable resource mix for the four scenarios.

Table 2-2. Non-hydro renewable resource mix for the Four Study Scenarios

	Scenario			
	2006	**2010T**	**2010X**	**2020**
Peak California Load, MW	58,900	62,600	62,600	74,300
Peak California ISO Load, MW	48,900	51,900	51,900	61,200
Total Geothermal, MW	2,400	4,100	3,700	5,100
Total Biomass, MW	760	1,200	1,000	2,000
Total Solar, MW	330	1,900	2,600	6,000
Total Wind, MW	2,100	7,500	12,500	12,700
Wind in Tehachapi Region, MW	760	4,200	5,800	5,800
Intermittent Penetration in CA	4%	15%	24%	25%
Intermittent Penetration in California ISO	5%	18%	29%	31%

Wind and solar generation resources are distributed among several sites in California. Table 2-3 illustrates the numbers of individual wind and solar sites represented in each scenario. The 2010T scenario includes 12 concentrating solar plants, 136 PV generation sites, and 98 wind generating plants, 40 of which are in Tehachapi. The 2020 scenario includes 43 concentrating solar sites, 228 PV generation sites, and 147 wind generating sites.

Table 2-3. Wind and Solar Generation in California

	Scenario			
	2006	**2010T**	**2010X**	**2020**
Concentrating Solar (CS)				
Number of Sites	7	12	42	43
Total CS, MW	330	1200	2100	3100
Photovoltaic (PV)				
Number of Sites	0 *	136	128	228
Total PV, MW	0 *	630	530	2900
Wind Plants				
Total Sites in California	57	98	142	147
Sites in Tehachapi Region	16	40	54	54
Total Wind, MW	2100	7500	12500	12700

* Existing PV generation aggregated with load

The California ISO supplied most of the historical grid operations data and therefore included only the California ISO operating area. Though municipal utilities were consulted and operations data requested, detailed analysis data was not made available to the IAP team. As a result, most of the statistical analysis focused on the impacts of intermittent generation on the California ISO operating area, as representative of the statewide. More specifically, the statistical analysis assessed the impact of wind and solar generation for each scenario compared to just the California ISO load. Although it is somewhat conservative in its approach, it is not too far from what is forecasted for California. As indicated in Tables 2-

4 and 2-5, a vast majority of variable renewable energy generation in the study scenarios is anticipated within the California ISO's operating area.

Table 2-4. Locations of Wind and Solar Resources for Scenario 2010T.

	Wind		Solar		Total Wind+Solar	
	MW	%	MW	%	MW	%
California ISO	7300	97%	1700	89%	9000	96%
Non-California ISO	200	3%	200	11%	400	4%
Total California	7500	100%	1900	100%	9400	100%

Table 2-5. Locations of Wind and Solar Resources for Scenario 2010X.

	Wind		Solar		Total Wind+Solar	
	MW	%	MW	%	MW	%
California ISO	11600	93%	2300	88%	13900	92%
Non-California ISO	900	7%	300	12%	1200	8%
Total California	12500	100%	2600	100%	15100	100%

2.4 Operational Impact Assessment

Once the load flows are completed and the resource mixes are established, production cost modeling is conducted for all four scenarios using General Electric's (GE) Multi-Area Production Simulation (GE-MAPS™) modeling software. The GE team consists of GE Energy Consulting, Rumla Inc. and AWS Truewind. This level of modeling helps evaluate grid operation with increasing levels of wind and solar generation; identify and quantify system performance and operation issues; and identify and evaluate potential mitigation strategies and options if necessary.

Based on the analysis of these scenarios, the anticipated results from the production cost modeling include the following:

- Projections on utilization, resource and capacity planning needs;
- Estimates of the potential impact of intermittent renewables on regulation, load following and unit commitment;
- Changes in transmission congestion, both in timing and of duration;
- Impact of intermittent renewables on operational and reliability performance measures;
- Changes in emissions of oxides of sulfur (SO_x), oxides of nitrogen (NO_x)and carbon dioxide (CO_2)due to changes in operations with increasing intermittent renewables resources;
- Insight on time and duration of operational constraints that may result in intermittent renewable energy not being delivered, and

- Quantifiable changes in the total cost of energy production in California from the added production of intermittent renewables

The IAP analysis spans across the operational and planning time horizons with a focus on a 2020 33% renewable energy scenario. Several different time scales are involved in grid operations and planning as illustrated in Figure 2-3. For example, frequency and regulation are performed on a second-to second basis. Unit commitment of generating units and forecasting are planned on a day-ahead or multi-day-ahead basis. Load growth and transmission infrastructure planning are performed at even greater intervals, spanning years.

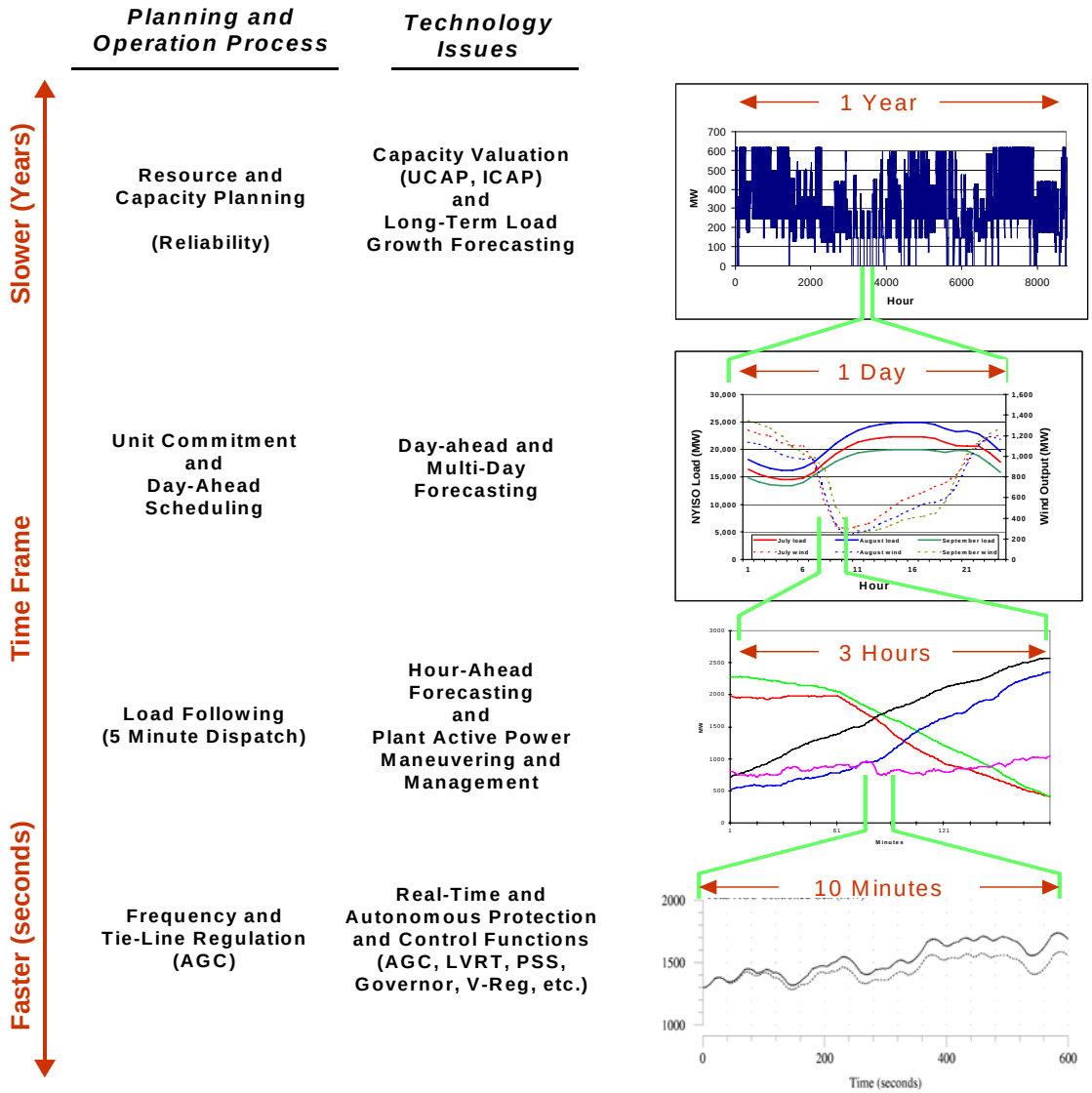


Figure 2-3. Time scales for grid planning and operations.

UCAP = uniform capacity, ICAP = installed capacity, AGC = automated generator control, LVRT = low voltage ride through, PSS = power system stabilizer, V-Reg = voltage regulation

3.0 IAP Findings

Project findings were reported by the IAP team at two public workshops held at the Energy Commission, one on August 15th, 2006 and a final on February 13, 2007. Detailed reports on all IAP findings and recommendations are available on the Energy Commission website (www.energy.ca.gov). Results reported in this section focus on the transmission expansion study conducted by DPC and the operational study conducted by GE. Full reports are provided in the Appendix of this report.

3.1 Transmission Analysis Results

3.1.1 Goals, Objectives, and Assumptions of IAP Transmission Analysis

The IAP project investigated the transmission impacts of higher penetration of intermittent resources such as wind and concentrated solar power on transmission adequacy and system security for different years, seasons and penetration levels. The goals of the transmission analysis for the IAP study were to:

1. Develop a methodology to evaluate the potential impacts of intermittent resources on the transmission grid;
2. Define a planning process by which conventional and renewable resources can be analyzed; and
3. Develop a common framework that can be used by agencies, utilities and developers to plan renewable and conventional resources that continue to support a reliable transmission grid.

To accomplish these goals, the following objectives were defined:

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

Before beginning the study of the impacts of intermittent renewables on the California transmission system, an evaluation process was developed, illustrated in Figure 3-1, that consisted of the following five steps:

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

- Step 2: Development of Study Cases and Renewable Mix Development.
- Step 3: Hourly Intermittency Analysis.
- Step 4: Maximum Renewable Penetration Analysis.
- Step 5: Wind and Load Correlation Analysis.

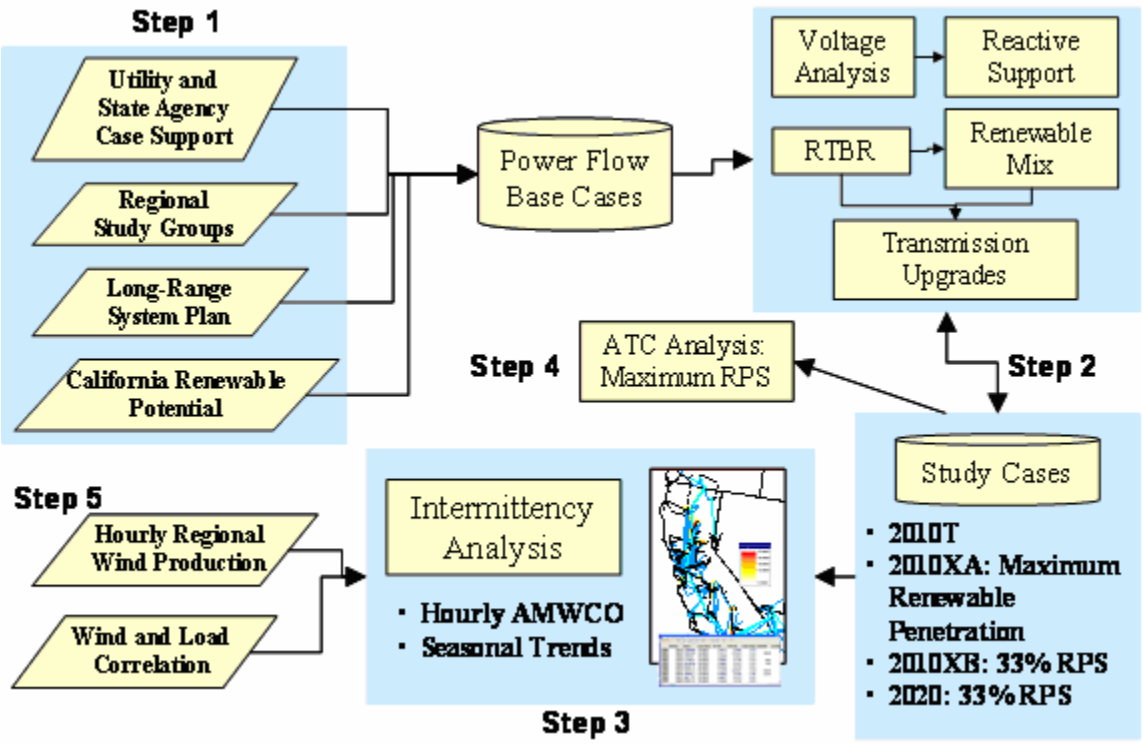


Figure 3-1: IAP Transmission Evaluation Process

ATC = Available Transfer Capability

Power flow models were compiled representing system load, conventional generation, and hydro dispatch patterns for projected summer peak, spring peak, and fall off-peak periods. California utilities and several working groups provided seasonal cases based on Western Electricity Coordinating Council (WECC) models and supplemental data from which base cases for the years of interest are compiled. The Energy Commission's state-wide load forecasts were applied to create base cases for each season in 2010 and 2020.

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

Additional direction concerning the characteristics of some specific renewable projects, such as the Tehachapi wind development and transmission at Imperial Valley, was provided by the Tehachapi and Imperial Valley Study Groups, with input from utilities and other

stakeholders. Transmission upgrades were added to each case to relieve transmission overloads under normal operating conditions. Combining the seasonal base cases with the renewable mixes and transmission upgrades yielded a set of study cases used to analyze the impacts of intermittent resources on transmission security.

Assumptions on plant additions and retirements were provided by the Energy Commission's Electricity Analysis Office (EAO). The EAO also determined the amounts and locations of gas-fired plants to be added in the IAP study in order to meet a 15% reserve margin. Table 3-1 lists the gas units, their projected location and the projected on-line date. More details are provided in Section 5-2 of the DPC report.

The 2010 and 2020 study cases use a wind output of 60% of the installed wind capacity for the summer, spring, and fall transmission power flow cases to determine the transmission expansion requirements. The same percentage is assigned to all of the wind sites equally. The transmission expansion may be over stated in some seasons under this modeling assumption. More detail is provided in Appendix A, Section 5-1 of the DPC report.

Table 3-1: New Gas-Fired Generators

AREA	STATUS	BUS	NAME	TYPE	MW	DATE
SDG&E	Retired	22780	SouthBy1			2008
SDG&E	Retired	22784	SouthBy2			2008
SDG&E	Retired	22788	SouthBy3			2008
SDG&E	Retired	22792	SouthBy4			2008
SCE	New	24151	VALLEY	CCCT- Frame H	387	2008
SCE	New	24151	VALLEY	CCCT- Frame H	387	2008
SCE	New	24151	VALLEY	DT	26	2008
SMUD	New	37524	Sutter	SCCT	150	2008
IID	New	21026	El CENTRO	SCCT	50	2009
LADWP	New	26025	HAYNES	SCCT	150	2009
PG&E	New	30873	Helm	CCCT- Frame G	250	2009
PG&E	New	30873	Helm	DT	30	2009
PG&E	New	30875	Mccall	CCCT- Frame G	250	2009
SMUD	New	37547	Folsom	SCCT	150	2010
SDG&E	New	22768	South Bay	CCCT- Frame G	140	2011
SDG&E	New	22772	South Bay	CCCT- Frame G	360	2011
SCE	New	24077	LBEACH	SCCT	150	2011
PG&E	New	30624	Tesla E	SCCT	150	2011
PG&E	New	30873	Helm	CCCT- Frame G	250	2011
PG&E	New	30875	Mccall	DT	15	2011
PG&E	New	31000	Humboldt	SCCT	150	2011
PG&E	New	33204	Potrero	SCCT	150	2011
SMUD	New	37549	Folsom	SCCT	150	2011
SCE	New	24077	LBEACH	SCCT	150	2012
SCE	New	24077	LBEACH	SCCT	150	2012
PG&E	New	30560	Eastshore	CCCT- Frame G	265	2012

AREA	STATUS	BUS	NAME	TYPE	MW	DATE
SCE	New	24401	ANTELOPE	CCCT- Frame G	259	2013
SCE	New	24401	ANTELOPE	CCCT- Frame G	259	2013
PG&E	New	32786	OAK C115	SCCT	150	2013
SMUD	New	37549	Folsom	SCCT	150	2013
PG&E	New	37585	Tracy	DT	26	2013
PG&E	New	37585	Tracy	CCCT- Frame G	265	2013
LADWP	New	26025	HAYNES	SCCT	150	2015
PG&E	New	33540	Tesla	SCCT	150	2015
SMUD	New	37016	Ranchoseco	CCCT- Frame G	250	2015
SMUD	New	37016	Ranchoseco	CCCT- Frame G	250	2015
SMUD	New	37016	Ranchoseco	DT	30	2015
TOTAL					5,849	

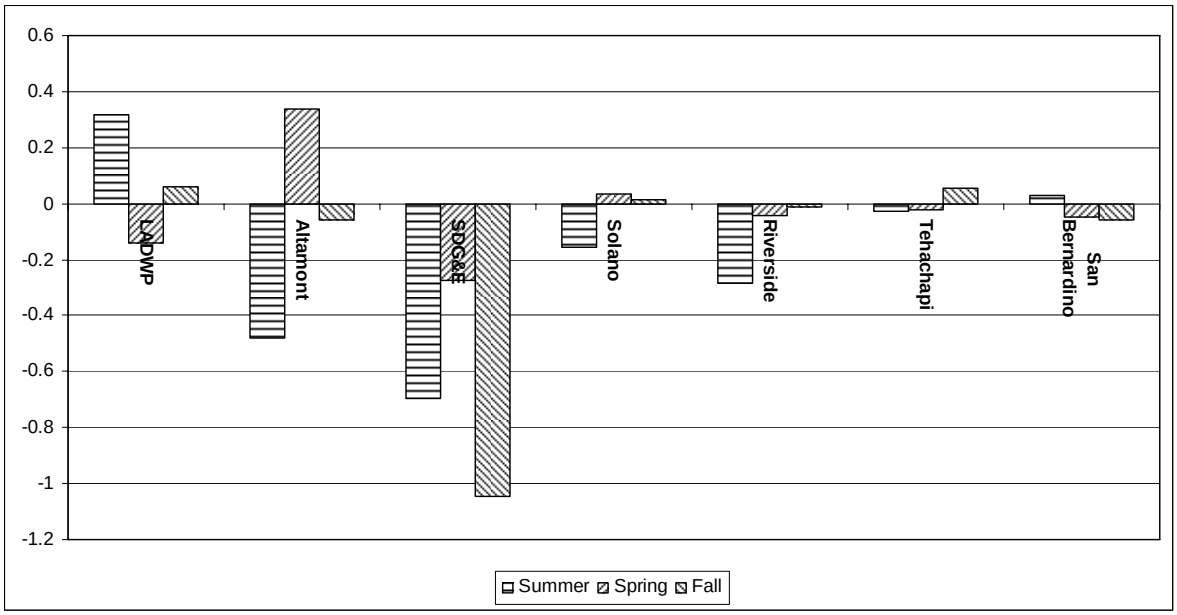
SDG&E = San Diego Gas & Electric Company, SCE = Southern California Edison Company, SMUD = Sacramento Municipal Utility District, IID = Imperial Irrigation District, LADPW = Los Angeles Department of Water and Power, CCCT = Combined Cycle Combustion Turbine, SCCT = Simple Cycle Combustion Turbine, DT = Duct Firing Combustion Turbine.

3.1.2 RTBR Results

Using the renewable resource mix outlined in Table 2-2, the system security of the study case is analyzed with non-variable production from normally intermittent wind and solar powered generators, in order to establish a baseline for later comparison of varying production. The system AMWCO metric provides a measure of security by totaling the amount of transmission overloading in California resulting from all single transmission element or generator (N-1) contingencies (approximately 7,000 total.) The change in security resulting from each proposed renewable project using the RTBR is analyzed. The RTBR measures the improvement in system AMWCO contributed by each renewable project, per MW of generation.

Figure 3-2 shows the seasonal RTBRs for the 2010 renewable resource mix by resource location. Negative values indicate that RTBR improves transmission reliability by reducing the AMWCO. There are only a few renewables locations that have positive values. For many locations, the RTBR values change in magnitude and sign by season.

In contrast, Figure 3-3 shows the RTBRs for the 2020 renewable mix. There are more renewables in the three seasons where the RTBRs are positive. A positive RTBR by itself does not mean that the project cannot provide net benefits to system operation. Transmission upgrades or operational remedial action schemes (RAS), including the effective re-dispatch of responsive conventional generation, may mitigate adverse RTBR locations observed in the study but will need to be further assessed by each utility.



[1]

Figure 3-2: 2010 Renewable Mix Seasonal RTBR by Location

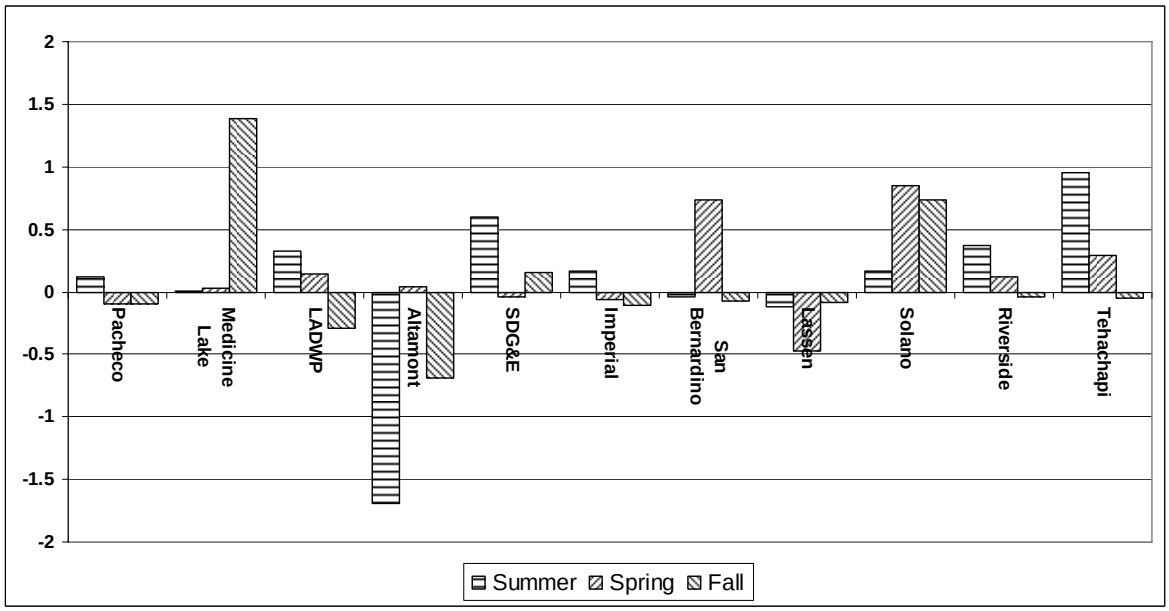


Figure 3-3: 2020 Renewable Mix Seasonal RTBR by Location

[1] Riverside is the same wind site as San Gorgonio.

3.1.3. Transmission Improvements Needed for 2010 Scenario

The results of the 2010 case developed for the IAP study indicate that the 2010 Tehachapi case can be met with in-state renewables if permitting, licensing and construction of transmission infrastructure is completed by 2010, and if the available renewable energy resources are the least cost-best fit alternative when compared to out-of-state renewable energy resources. Required infrastructure improvements include 74 new or upgraded transmission line segments (i.e., section of a line between two substations) ranging from 69 kilovolts (kV) to 500 kV. Most of the 500 kV upgrades are associated with wind development at Tehachapi. A majority of the upgrades (63) are lower voltage improvements to move power to the growing load. A first order estimated cost for just the 500 kV and 230 kV transmission lines and tower upgrades or additions is approximately $1.2 billion (excluding detailed land use and right of way costs).

In addition to the transmission line upgrades, several transformer upgrades are also identified for the 2010 case development. A total of 31 transformers are added or improved, most of which are upgrades to transformers in lower voltage substations. A first order estimated cost for the transformer upgrades is $161 million (excluding detailed land use and right of way costs).

3.1.4 Transmission Improvements Needed for 2020 Scenario

The 2020 renewable energy target can also be met with in-state renewable resources, but requires even more extensive transmission upgrading to meet load growth and new power plant construction. Many of the transmission upgrades used in the IAP study are currently being planned. In addition, whether the 2020 target can be met is dependent on permitting, licensing and construction of transmission infrastructure being completed by 2020, and if the available renewable energy resources are considered the best alternative when compared to out-of-state renewable energy resources.

Necessary infrastructure improvements to meet this target include 128 new or upgraded transmission line (i.e. section of a line between two substations) ranging from 69 kV to 500 kV. Most of the 500 kV upgrades are associated with the Tehachapi wind development, the SDG&E Sun Path expansion project, and a fourth California Oregon Intertie (COI) line (with supporting area upgrades.) A majority of the upgrades (66) are lower voltage improvements to move power to the growing load. An estimated cost for just the 500 kV and 230 kV transmission line and tower upgrades or additions is approximately $5.7 billion.

In addition to the transmission line upgrades, several transformer upgrades are also identified for the 2020 case development. A total of 40 transformers are added or improved, most of which are upgrades in higher voltage substations. An estimated cost for the transformer upgrades is $655 million. Table 3-2 provides the 2010 and 2020 transmission expansion results from the IAP transmission analysis. Non-disclosure agreements prevent the IAP project from releasing the locations of the proposed new transmission, although Figure 3-4 provides an approximate location from a state-wide perspective.

Table 3-2. 2010 and 2020 Transmission Expansion Results

Voltage	2010 Line Segments	2020 Line Segments	2010 Transformers	2020 Transformers
500	8	22	2	9
230	8	38	6	18
161/138	0	2	1	0
115	49	49	9	5
Below 110	13	17	14	8
Total	78	128	32	40

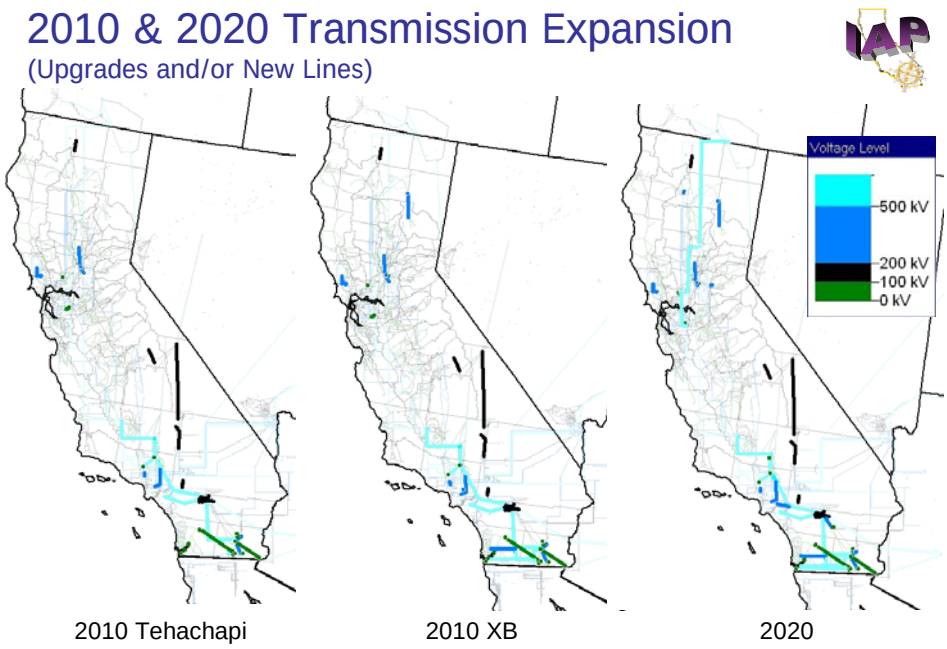


Figure 3-4. 2010 and 2020 Transmission Expansion for the IAP Project

3.1.5 Voltage Stability

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

case voltages) and then planning studies evaluate those base cases as load and generation growth are modeled out to future years.

3.1.6 Transmission Intermittency Analysis Results

Wind intermittency requires the transmission system to be capable of supporting a variety of wind generation patterns, as variable regional wind production gives rise to variable power transfers across the system. The variable wind conditions are simulated for each of the seasonal study cases with historical regional hourly capacity factors provided by the California ISO.

The transmission study used the 2004 historical wind production data represented by five major wind regions. The California wind regions from the 2010 Tehachapi and 2020 cases are assigned to one of the five existing wind regions shown in Figure 3-5. As such, the transmission results may have some bias due to the limited data. For example, all the wind sites south of San Gorgonio are assigned the same hourly wind pattern as San Gorgonio. This may result in less realistic wind variation as all wind units in the same region will be following the same output pattern, as opposed to each individual unit having its own pattern. However, the methodology developed to study intermittent resources is still useful for indicating transmission system concerns from the regional wind variation. Further refinements may be made using the IAP hourly forecasted wind data provided by AWS Truewind or site data as new information becomes available.

Figure 3-5. Wind Generation Regions

Source: California ISO

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

- The Proposed Tehachapi – Midway 500 kV Upgrade exhibits overloading on a series capacitor during periods of high Tehachapi production. If bypassing the capacitors during periods of high loading is not operationally feasible, the capacitors should be sized to handle the rated load of the transmission lines served.
- The high voltage transmission lines north of Midway experience various levels of transmission overloads depending on the season and the wind generation. The lines tend to have overloads during the fall seasons of various durations depending on the wind generation from Tehachapi, Solano and Altamont. When Solano and Altamont are low and Tehachapi high, there are more transmission problems.
- The Vaca Dixon – Peabody 230 kV line exhibits extreme loading variability and vulnerability to thermal overloads under contingencies across seasons, especially in the 2010 XB and 2020 scenarios.
- The COI and 500 kV paths south of the COI are vulnerable to thermal overloads during periods of high Northwest imports. Variable wind production imparts some variability to the level of contingency overloading on the COI as other resources are dispatched during periods of low wind.
- The low voltage collector network in the Altamont region may require upgrades if circuit breaker operation and other RAS (e.g., dropping load or branch switching) are unable to alleviate overloading observed during periods of low Altamont wind production.

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

Under contingency analysis, a few hours of extremely high system AMWCO levels occur during a period of unusually high Tehachapi production, which coincides with low wind production in northern California. The proposed Tehachapi – Midway 500 kV circuit overloads under contingencies, as in the base case. The line includes a modeled capacity of 1,848 mega volt amperes (MVA), limited by one of its series capacitors. The capacitor rating may be inadequate to support some wind patterns, unless conventional resources in Northern California are dispatched to sufficiently offset south to north flows or unless the

capacitors are bypassed during heavy loading. The contingency rating of the proposed transmission line itself is 2,567 MVA.

The variability caused by greater reliance on intermittent resources may require mitigation with special protection schemes that limit the magnitude of hour-to-hour changes in wind production or curtail wind if production exceeds the capacity of the transmission network to deliver wind energy to the load. To the extent possible, fast responding load-following resources such as simple cycle gas turbines could be needed and be strategically re-dispatched by region in response to varying wind conditions.

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

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

3.1.7 Data Compatibility and Input Data Limitations

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

In addition to the topological issues, the interchange assumptions in all WECC power flow data sets are preset to maximum imports and/or exports, which make re-dispatching of resources in the power flow model difficult. The import/export extremes are maintained in

the data sets for the IAP study, but should be modified in future studies to an import/export schedule more representative of "normal" operating conditions. In the IAP study, the extreme imports/exports did force an extended set of non-reliability-must-run units to be used as generation offset for the renewable resources being added to the data sets.

It is recommended that consistent base cases for all represented renewables be produced and made available for future studies in the region (i.e. WECC).

3.2 Results from the Statistical and Production Cost Modeling Analysis

GE Energy Consulting conducted statistical analysis and production simulation analysis of the California grid to determine the operational impacts of intermittent renewable energy generation. The statistical analysis provides a broad view of the relative contribution of the intermittent renewables to system generation and overall system variability. For the production cost modeling, the entire WECC grid was modeled in addition to California, and all transmission constraints in the WECC Path Rating Catalogue were considered.

The statistical analysis and production cost models are tools to capture the hour-by-hour and minute-by-minute impacts on operation. The statistical analysis also involved searching through the hourly data for periods that warrant more detailed analysis. For example, 50 different sample periods are assessed for 2010 to look at sub-hourly system impacts (Figure 3-6). The characteristics of such periods include:

- Large changes in load over 1-hour and 3-hour periods.
- Periods of high wind and solar generation.
- Periods of high penetrations of wind and solar.
- Low load periods.
- Large changes in wind and solar over 1-hour and 3-hour periods.
- Periods of high wind with low wind variability.

Data was aggregated into 3-hour blocks and the top 20 3-hour blocks for each category (largest change in load, periods of high wind and solar generation, low load periods, etc.) was compiled. Fifty specific 3-hour periods were selected and differentiated by year, season, time of day, changes driven by load, wind or solar, and direction of changes, whether up or down. The 50 periods are cataloged in Table 3-3.

Sub-hourly statistical analysis was conducted on these 3-hour periods for each season similar to the 1-hour data set. The seasons are classified by the Gregorian calendar. The largest 3-hour change in MW represents the biggest group, with 15 periods, followed by the group of high wind capacity with low wind variability with 11 periods and the largest 1-hour change in capacity with eight periods. Of the 50 periods, spring is reflected in 20, followed by summer with 17, winter with eight and fall with five. For each 3-hour period, 1-minute MW output profiles were developed for wind and solar resources, and 1-minute load data was obtained from the California ISO.

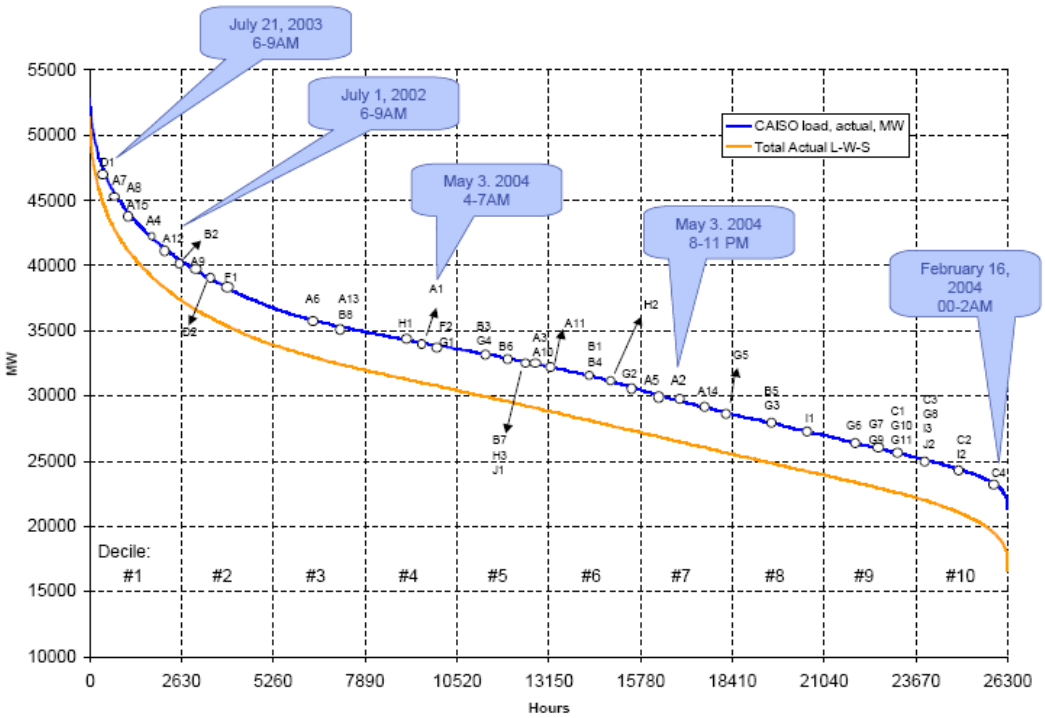


Figure 3-6. 2010 hourly load and L-W-S duration curves with 50 assessment periods

L-W-S = Load minus wind minus solar.

Table 3-3. Selected periods for sub-hourly analysis

	Year	Season	Month	Day	End Hour
Large 3-Hour Delta MW (Group A)	2004	Spring	5	3	7
	2004	Spring	5	3	23
	2004	Fall	10	28	7
	2004	Summer	7	19	9
	2004	Summer	9	6	23
	2004	Summer	9	7	22
	2003	Summer	7	21	10
	2003	Summer	8	12	10
	2003	Summer	7	19	10
	2003	Summer	6	26	23
	2003	Spring	5	28	23
	2002	Summer	7	1	9
	2002	Summer	7	9	23
	2004	Spring	4	27	23
	2004	Summer	8	10	10
Large 1-Hour Delta MW (Group B)	2004	Winter	1	30	6+1
	2002	Winter	1	30	18+1
	2003	Spring	4	10	7+1
	2004	Winter	12	31	17+1
	2003	Spring	4	7	19+1

	Year	Season	Month	Day	End Hour
	2003	Winter	2	9	18+1
	2002	Winter	2	14	22+1
	2003	Spring	5	28	22+1
Low Load Periods (Group C)	2002	Fall	10	14	4+1
	2003	Winter	2	2	6+1
	2002	Fall	10	27	23+1
	2004	Winter	2	16	1+1
Largest 3-hr Delta W+S (D)	2003	Summer	7	21	19
	2004	Fall	11	29	18
Largest 1-hr Delta W+S (F)	2004	Summer	6	24	19+1
	2003	Fall	10	31	17+1
High Wind MW with Low Wind Variability (Group G)	2002	Summer	7	3	22+1
	2002	Summer	6	27	23+1
	2002	Summer	6	19	2+1
	2002	Spring	6	3	22+1
	2003	Summer	7	3	24+1
	2003	Summer	6	20	24+1
	2003	Spring	5	15	4+1
	2003	Spring	5	24	24+1
	2003	Winter	3	17	24+1
	2004	Spring	5	10	24+1
	2004	Spring	5	18	24+1
Highest Wind MW (Group H)	2002	Spring	5	20	18+1
	2003	Spring	5	8	18+1
	2004	Spring	5	28	19
Highest Wind Penetration (Group I)	2002	Spring	6	18	2+1
	2003	Spring	5	15	2+1
	2004	Spring	5	29	1+1
Highest Wind+Solar MW (J)	2004	Spring	5	28	17
Highest Wind+Solar	2004	Spring	5	29	1+1

Note: The +1 indicates that the ending time for this period was increased by one hour to place the most interesting hour in the middle of the period.

3.2.1 Example of Quasi-Steady-State Simulation Analysis

Three primary study periods were chosen for further analysis using quasi-steady-state (QSS) simulation. The QSS analysis consists of detailed time simulations of specific 3-hour periods and is designed to illustrate key aspects of system performance and potential mitigation measures within the broader context of the statistical and production simulation analyses. As such, the QSS analysis is tightly linked to both of these analyses. All QSS analysis was performed using GE's Positive Sequence Load Flow (PSLF) software package.

The three study periods consisted of:

1. July morning with both a load increase and a net decrease in wind and solar generation,
2. May night with both a low load level and high wind penetration, and
3. June evening with both a load decrease and a significant increase in wind generation.

The May night case will be discussed in brief to illustrate the QSS methodology. Additional information and the details of all cases are available in Appendix B, Chapter 5 of GE's report.

Conditions:

- The May night study period occurred between 1 a.m. and 4 a.m. and was evaluated under the 2010X renewable scenario, which includes about 12,500 MW of wind generation capacity at 142 sites and 2,600 MW of solar generation capacity at 42 concentrating solar plants and 128 PV sites.
- The load was derived from 2003 data. The units available in the QSS analysis are a subset of both the total number of units in California as well as the units available in the production analysis. Thus, the analysis is slightly conservative.
- The May night study period represented a relatively light load condition (25,100 MW) with a high level of instantaneous wind penetration (10,200 MW or 41%). There is no solar generation profile at night. Neither the load nor the wind changed significantly over the 3-hour study period.
- The statistical analysis of three years of hourly data showed the peak wind generation output was 11,500 MW, and wind generation was greater than 10,000 MW for less than 1% of the hours. The average hourly intermittent penetration at light load was about 29%, and the peak hourly intermittent penetration was about 39%.

Observations:

- Several load steps greater than +/- 200 MW were observed during the May night study period, likely due to switching pumped storage hydro facility pumps or other large loads.
- The QSS analysis determined that the economic dispatch units run out of down-ramp rate capability at about 1:30 a.m., and at about 1:45 a.m., the economic dispatch units run out of down range. Therefore, all down rate capability is exhausted by that point.
- After about 3:15 a.m., the net load has increased such that some down maneuverability is recovered

Based on this analysis, two major findings are:

1. Large steps in load have more significant impact on the regulation duty than the variability of load and wind.
2. Insufficient down capability (both range and ramp rate) shifts load following duty to regulation, which may then become exhausted. This in turn may result in a violation of CPS2 criteria.

A sensitivity case was performed to evaluate the impact of increasing the maneuvering capability of the balance-of-portfolio generation by changing the generation commitment. This was accomplished by replacing 2,200 MW of baseload generation with 2,200 MW of combined-cycle generation. It was determined that neither down range nor down ramp rate capability is exhausted, suggesting that replacing non-maneuverable generation with maneuverable generation in the balance-of-portfolio (i.e., non-renewable generation) effectively mitigates loss of both down range and down ramp rate capability under light load conditions.

Another sensitivity case was performed to explore the temporary curtailment of wind generation. The curtailment consisted of a relatively fast reduction in wind generation of about 500 MW over 5 minutes. The reduction was applied at about 1:15 a.m. before all down maneuverability was exhausted in the original May simulation. Total wind production was curtailed for the next two hours. The curtailment was removed after some down maneuverability was recovered in the original May simulation at about 3:30 a.m. Wind farm output was allowed to increase over about 10 minutes back up to that available due to the prevailing wind. This temporary curtailment was implemented at all wind farms, with each reducing its output by a share of the 500 MW proportional to its rating. The wind energy lost during the curtailment was about 1,400 MW-hr out of about 30,000 MW-hr, or 3.8%, for this 3-hour period. As noted above, the statistical analysis of three years of hourly data showed total wind generation was greater than 10,000 MW for less than 1% of the hours. Hence, this is a rare occurrence. The analysis found that the remaining non-renewable generation maintains sufficient maneuverability to follow load. Therefore, curtailment of wind effectively mitigates loss of maneuverability under extreme light load, high wind conditions. Curtailment would also allow the wind plants to provide regulation. For details on the QSS analysis refer to Appendix B, Chapter 5.

3.2.2 Key Findings by Operational Time Frame

Extensive quantitative results were produced in GE's analysis (Appendix B). This section summarizes key qualitative findings by operational time frame. Of the four scenarios studied, the accelerated 2010X scenario represents the most challenging. However, the observations, conclusions and recommendations presented in this section apply to all scenarios, not just the most challenging.

Day-Ahead and Overall Operation

Intermittent renewable generation will displace other more expensive generation, i.e., generation with a higher marginal variable cost. Because natural gas combined-cycle power plants are frequently on the margin in WECC, most of the displaced generation is combined-cycle. Roughly half of the displaced generation is inside California and the other half outside (Appendix B, Section 4.4.).

Conventional hydroelectric facility operation within the state is temporally shifted due to wind and solar generation. However, the change in operation is less than 1,000 MW more than 90% of the time, on a hydro system with over 9,000 MW of capacity (Appendix B, Sections 4.4, 4.4.1). The conventional hydro facilities should be able to provide this maneuverability, particularly when augmented by the available pumping loads.

Day-ahead operations will be less certain as intermittent resources increase. Total load and intermittent renewable forecast errors will be roughly twice that of the load forecast error alone. This may increase the operation of peaking generation when other generation is under-committed due to over-forecasting of intermittent renewables. The increased use of peaking combustion turbines offsets some of the economic value of the intermittent renewables. This uncertainty was included in the analysis. System performance based on currently available load data and wind forecasting technology was satisfactory (Appendix B, Sections 3.5.1, 4.7).

Hourly Schedule Flexibility

The requirements for hourly schedule flexibility increase over time due to both system load growth and additional intermittent renewables. Three times the standard deviation of one-hour change, which was the primary metric of required schedule flexibility, shows the relative impact of these two components. The increase in hourly variability due to load is substantially greater than the impact of wind and solar for the expected intermittent renewable scenarios (2010T, 2020). The load growth through 2020 continually increases the schedule flexibility requirement. The incremental requirement due to load growth from 2006 to 2020 is about 1,700 MW/hr. The intermittent renewables uniformly increase the schedule flexibility requirement above the load alone requirement by about 130 MW/hr for these scenarios (Appendix B, Sections 3.2 and 6.2.1).

A comparison between the 2006 and the artificially stressed 2010X scenarios shows the increase in schedule flexibility requirement due to load alone is about equal to that due to the accelerated addition of intermittent renewables (Appendix B, Section 6.2.1).

The addition of zero marginal cost intermittent renewables will displace other generation with higher marginal operating costs. This means that the commitment and dispatch of the other generation resources necessary to provide operational flexibility will change. In general, the ability to dispatch down at light load and to dispatch up at heavy load represents the limiting condition (Appendix B, Section 4.4.3).

The analysis of the available range to dispatch up at peak load showed no limitations. Range (i.e., the remaining capacity in megawatts available between the current operating point and either the maximum or minimum) measures the ability of the balance-of-portfolio (i.e., non-renewable) generators to respond to changing load, wind and solar conditions in the hourly time frame. The available range to dispatch down at light load was also adequate. However, limitations may be encountered with coincident minimum load, high wind generation and low conventional hydro flexibility. Conventional and pumped storage hydro generation as well as pump loads play an important role in providing the necessary schedule flexibility (Appendix B, Section 6.3.2).

During daily real-time operation, the incremental hour-ahead uncertainty due to intermittent renewables is much less than day-ahead values. The combined hour-ahead forecast error is about 20% greater than that for load alone (Appendix B, Section 3.5.2).

The analysis found that a rational, i.e., least cost, dispatch and commitment of available resources results in satisfactory operation in this time frame (Appendix B, Section 4.7).

5-Minute Load Following and Economic Dispatch

An examination of the change in the standard deviations in the 5-minute time frame shows the relative impact of load growth and additional intermittent renewables on the load-following requirements. Load growth will increase the load-following requirement about 10% by 2010 and about 35% by 2020. The intermittent renewables will further increase that requirement by 3% to 7%. Although the relative increase is greater at light load, the light load requirement itself is less than the overall requirement (Appendix B, Sections 3.3, 6.2).

The load following capability at any given operating point is dictated by unit commitment and dispatch. Ramp rate capability (i.e., the speed (MW/minute) at which the system can use the remaining up and down range) measures the ability of the balance-of-portfolio (i.e., non-renewable) generators to respond to changing load, wind and solar conditions in the 5-minute time frame. The available ramping capability of on-line units, both up and down, was found to be largely adequate. Under light load conditions, various mitigation strategies (e.g., selective wind curtailment and thermal unit recommitment) were effective in relieving load-following limitations should they occur (Appendix B, Sections 5.2.2, 6.3.2).

1-Minute Regulation

The 1-minute variability also increases with load growth, and is further increased by the addition of intermittent renewables. On a percentage basis, the increase in regulation requirement due to load growth and due to intermittent renewables are similar to the load-following increases. Unlike the hourly and load-following time frames, however, regulation

requirements are relatively uncorrelated to system load level. The increase in regulation requirement due to the intermittent renewables is about 3% to 7%.

Insufficient load-following capability increases the need for regulation capability. Rapid variation in load as well as intermittent renewable production will increase the area control error (ACE), which also drives a greater use of regulation. Any increase in ACE may degrade NERC Control Performance Standard 2 (CPS2) performance. If no changes are made to the present regulation procurement, the impact on CPS2 is about 2% (Appendix B, Sections 3.3, 5.2.3, 6.3.4).

3.3 Recommendations

Two scenarios (2010T and 2020) represented steps on an expected trajectory to meet California's renewable generation goal. The accelerated 2010X scenario was developed to increase system stress and represents the most challenging study condition. However, the conclusions and recommendations presented in this section apply to all scenarios, not just the most challenging. They are intended to enable consistent, sustained renewable growth through 2020.

The 2010X scenario examined a total of 19,800 MW of renewables in California, including 12,500 MW of wind generation, 2,600 MW of solar, 1,000 MW of biomass, and 3,700 MW of geothermal. This scenario represents a stressed condition designed to test the system with more renewables than projected for 2010.

This level of renewable generation can be successfully integrated into the California grid provided appropriate infrastructure, technology, and policies are in place. Specifically, this successful integration will require:

- Investment in transmission, generation and operations infrastructure to support the renewable additions,
- Appropriate changes in operations practice, policy and market structure,
- Cooperation among all participants, e.g., California ISO, investor owned utilities, renewable generation developers and owners, non-Federal Energy Regulatory Commission (FERC) jurisdictional power suppliers, and regulatory bodies.

The study scenarios represent stages along a trajectory to meet California's renewable generation goal by 2020. The following recommendations are a set of targets, actions and policies designed to ensure successful integration of significant levels of intermittent renewable generation into 2020. The implementation of these recommendations should proceed concurrently with the renewable generation growth. Such evolutionary improvements will allow secure and economic integration at all stages along the renewable generation growth trajectory.

The challenge of accommodating substantial intermittent renewable generation is incremental to the challenge of serving existing and new load. Long term planning must always consider requirements for transmission, generation, and strike an appropriate

balance between the two. Further, new considerations specific to renewable technologies must be included. Thus, the planning process must consider three major system components:

- Generation Resource Adequacy
- Transmission Infrastructure
- Renewable Generation Technology, Policy and Practice

The recommendations presented below are grouped accordingly.

3.3.1 Generation Resource Adequacy

The Energy Commission, CPUC and California ISO have ongoing processes to provide the generation infrastructure necessary to maintain reliable operation. The addition of both intermittent and non-dispatchable renewable resources to the California grid increases the requirement for generation resource flexibility. It is essential that this requirement for flexibility be included in the overall assessment and planning for resource adequacy. It is recommended that specific attributes of generation flexibility be inventoried, maintained, and increased. Where possible, quantitative targets are suggested; others may be adopted as circumstances and understanding changes. To avoid repetition, specific policy and technology recommendations are grouped with the most relevant performance issue. However, many recommendations could apply to a broader range of performance categories. Further, none of the recommendations are either self-sufficient or mutually exclusive. An appropriate combination of means will be most successful.

Minimum Load Operation. The California grid should target a combination of in-state generating resources and power exchange capability/agreements with neighboring systems that allow operation down to a minimum net load (load minus wind minus solar) in the range of 18,000 MW to 20,000 MW. These targets will meet the long-term (2020) needs of the system, and allow for operation with minimal curtailment of intermittent renewables.

- *Minimum Turndown.* Generating resources with lower minimum power output levels provide greater flexibility, and allow successful operation at minimum load. New generating resources should be encouraged and/or required to have this capability; existing generation should be encouraged and/or required to upgrade their capability. A comparison of the load and net load (load-wind-solar) for the various scenarios shows that minimums are less with the intermittent generation on the system. The minimum system turndown capability will determine the amount of renewable generation curtailment that is necessary. A minimum of 20,000 MW is expected to result in curtailment during a few hundred hours per year for the expected growth trajectory.

- *Diurnal Start/Stop*. Another way to meet minimum load is to increase the amount of generation that is capable of reliable diurnal cycling. This will benefit the

system by allowing the commitment of units that are economic at peak and shoulder loads, without requiring their non-economic operation at light load.

- *Load Participation*. Active participation by large loads, especially pumps, is another way to assure adequate flexibility. The pumps controlled by the California DWR are already participants in the energy market, but additional types of participation and cooperation could increase overall system flexibility. For example, additional investment in pumps, controls or other load infrastructure to take advantage of light load energy pricing could be both economic and effective.

- California should explore other means to encourage load shifting towards light load conditions. Various load shifting and storage technologies, such as cold storage (e.g. for building cooling or inlet air cooling for gas peaking generation) hold promise, and may prove to be economic. Arrangements that give the grid operator control over loads for a contractual consideration or rate reduction will be more attractive as penetration of intermittent renewables increases.

- *Pumped Storage Hydro*. Use of pumped storage hydro (PSH) facilities was shown to increase for the scenarios examined. The infrastructure and policy necessary to allow optimal use of existing PSH within California should be enhanced. Additional PSH capability could also enhance system scheduling flexibility, and will likely aid other flexibility attributes discussed below. This is particularly true when conventional hydro flexibility is low, due to unusually high run-off conditions.

Hourly Schedule Flexibility. The California grid should target a combination of in-state generating resources that provide a minimum level of scheduling flexibility. The anticipated load growth to 2020 will drive the overall system flexibility needs from the present level of about 4,300 MW/hr to about 6,000 MW/hr. The additional variability and uncertainty associated with intermittent renewables will increase the amplitude of sustained load ramps (both up and down), and the frequency of generation starts and stops. For the expected renewables growth trajectory (2010T, 2020), the overall hourly flexibility requirement is expected to be about 130 MW/hr greater than that required for load alone. Under the artificially accelerated renewable expansion of the 2010X scenario, that incremental requirement is about 400 MW/hr.

During light load conditions, total requirements are smaller but the relative impact of intermittent renewables is larger. The anticipated load growth to 2020 will drive the light load system flexibility needs from the present level of about 2,000 MW/hr up to about 3,000 MW/hr. For the expected renewables growth trajectory (2010T, 2020), the hourly light load flexibility requirement is expected to be about 1,000 MW/hr greater than that required for load alone.

- *Hydro Scheduling*. Conventional hydroelectric generation plays a key role in light load schedule flexibility as well as load following and regulation. Economic

operation will be enhanced by high hydro flexibility. Existing flexibility should be maintained at least, and investments to increase maneuverability should be considered. A documented inventory of capability is important. California should periodically examine the amount and type of hydro constraints, and evaluate investments or contractual mechanisms for cost-effective relief of those constraints.

- *Faster Start/Stop.* Uncertainties in forecasts create a somewhat different flexibility requirement. Even with state-of-the-art wind forecasting, both day-ahead and hour-ahead net load forecast uncertainties will increase due to intermittent renewables. With an increased risk of an actual net load significantly different from the forecast net load, short-notice start/stop capability during daily operation will be an important part of the redispatch needed to balance generation and load. The California grid should target sufficient in-state generating resource capability to meet day-ahead forecast errors in the range of ±5,000 MW, and hour-ahead forecast errors in the range of ±2,000 MW. Overall, this represents about double the present level of day-ahead load forecast error and about 20% more than the present hour-ahead load forecast error.

  During lighter load periods, the net load forecast error may be three times the load alone forecast error in the day-ahead forecast. The targets recommended above will also be sufficient for light load conditions.

Multi-Hour Schedule Flexibility. Flexibility targets should also address periods of sustained load increases and decreases. The recommended targets are for the California grid to have resources adequate to meet a maximum morning load increase of 12,000 MW over three hours, and a maximum evening load decrease of 14,000 MW over three hours. This represents an increase of about 1,000 MW over the capability needed to meet the load alone.

Load Following Capability. The California grid should target a combination of in-state generating resources that provide a minimum level of generation ramping capability, both up and down. On average, the system should maintain on the order of +/-130 MW/min for a minimum of 5 minutes. This is about a 10 MW/minute increase over the requirement due to load alone.

During light load conditions, approximately 70 MW/min of down load-following capability are required. Up load-following requirements are lower. The load-following capability should be subject to economic dispatch from the system operators. Load following duty should not be shifted to units providing regulation.

- *Import/Export Scheduling*. The California grid should recognize that economic incorporation of substantial in-state renewables will inevitably involve significant displacement of imported energy. Regulatory and contractual arrangements for imports and exports should be structured such that the value of scheduling flexibility is recognized, allowed and appropriately compensated.

In particular, California should allow schedule changes to occur more frequently and at times other than on the hour.

Regulation Capability. The California grid should target a combination of in-state generating resources that provide a minimum level of regulation capability. The California ISO currently procures regulation in the range of 300 MW to 600 MW. The procured amount varies substantially over all load levels. The impact of intermittent renewables on regulation (20 MW) is considerably less than the normal variability in the amount procured. However, regulation resources will continue to be important. Therefore, the California grid should at least maintain the current level of regulation capability. This level of regulation should allow the state to continue to satisfy their regulatory obligations for interchange and frequency control, i.e. NERC CPS2 performance. CPS2 performance should be continually scrutinized as intermittent renewables are added to the grid to refine regulation requirements and procurement.

- *Regulation Technologies*. California should consider the use of technologies beyond conventional generation to provide regulation. The earlier discussion about load participation in schedule flexibility applies here as well. Functional requirements for loads to provide regulation are different from those for generation. Given a suitable regulatory and market structure, however, it is likely that other technologies and participants will emerge to provide the required services. Examples include some types of storage technology, such as variable speed pumped hydro and the latest flywheel energy storage systems. Policy and market structure should encourage diversity of participants in providing ancillary services, and technical specifications for performance should be sufficiently flexible to allow the introduction of new technologies.

Non-Technical Resource Adequacy Considerations. The preceding recommendations were aimed at securing the technical capabilities necessary for successful integration of intermittent renewables. The following items address policy and commercial considerations:

- *Market Design.* It must be recognized that while operational flexibility is of considerable value to the grid, it currently holds little attraction for power suppliers. Deeper turnback, more rapid cycling and load following, and more frequent starts and stops all impose significant costs and revenue reductions on the suppliers. Market and regulatory structures must recognize the value of these flexibility features. Policy changes may include a combination of expanded ancillary services markets, incentives, and mandates.

- *Contractual Obligations.* Much of the analysis presented in this report is based on the presumption that the grid is operated in a rational fashion – that is, the available generation resources are used as efficiently and economically as possible. The analysis did not include historical constraints (i.e. long term contractual obligations) that force the system to run less efficiently than possible. New contracts under consideration, existing long-term contracts up for renewal,

or indeed any existing contracts that could be renegotiated should be reviewed with all of the preceding resource adequacy recommendations in mind. The California grid must maintain operational flexibility, and to do so, it must have not only the physical resources necessary, but also the business and contractual arrangements necessary to enable the rational use of those physical resources.

- *Retirements.* Generating plant retirements that were firmly scheduled when the databases were assembled were incorporated into this study. However, increased competition from new resources, renewable or otherwise, will tend to push marginally profitable generating resources out of business. Such speculative, economic retirements were not considered in the study. Successful implementation of the recommendations above will ensure that resources with the necessary flexibility are available. In addition, it is recommended that retirements be projected, monitored, and evaluated during the resource planning process.
- *Inventory.* During this study, it was noted that generator characteristics and capabilities (e.g., minimum turn down, ramp rate capability) were not always known with sufficient detail or certainty. Some degree of uncertainty is inevitable. However, with the increased need for resource flexibility, California should implement a program to measure, verify, and catalogue the flexibility characteristics of the generation resources. A program similar to the WECC generator dynamic testing might prove suitable.

3.3.2 Transmission Infrastructure

The addition of thousands of MW of new generation of any variety will require expansion of the transmission system. The DPC study identified the need for 74 new or upgraded transmission line segments (a section of a line between two substations) for the 2010 Tehachapi case and 128 new or upgraded transmission line segments for the 2020 case. However, the DPC study is not a detailed transmission study and is not a substitute for one. Policies must recognize that local problems might develop, and enable the necessary transmission additions. Practice and policy that correct problems and strike a balance between infrastructure investment and congestion are necessary. To an appreciable extent, this observation holds for all transmission planning and all generation additions. California can economically benefit from changes in planning and operation of the transmission infrastructure by recognizing the locational and variable nature of intermittent renewables. The following are recommendations that are specific to these needs:

Existing Constraints. California has existing infrastructure that is valuable for secure and economic operation of the grid with high levels of intermittent renewables. That infrastructure should not be constrained by local transmission limitations. One example of such a constraint is the occasional inability of Helms pumped storage hydro to reach full pumping power.

Rating Criteria. Conventional planning criteria require sufficient transmission system capability (i.e. thermal rating) to accommodate all power plants at simultaneous peak output. These criteria need to be re-examined to accommodate significant levels of intermittent renewable generation. Wind generation is variable and the spatial diversity between multiple plants substantially impacts the coincident production of power from those plants. Clearly, an individual wind plant will reach rated output for many hours per year. Thus conventional transmission rating criteria still applies to the design of transmission dedicated to that plant.

However, as more wind plants vie for access to specific transmission corridors, it will be progressively less likely that all wind plants will simultaneously reach their maximum output. Note that in three years of data, all wind plants in this study *never* simultaneously reached maximum output. And, the 12,500 MW of wind generation exceeded 10,000 MW of production less than 1% of the time. Thus, transmission planning to accommodate multiple wind plants should consider their spatial diversity and the statistical expectation of simultaneous high power output levels. Plants in close proximity will generally require transmission capability equivalent to the aggregate rating of the plants. Plants that are farther apart may require less transmission capability. Hence, it is not necessary to guarantee sufficient rating on the bulk transmission infrastructure to accommodate all wind projects at full output.

Technology. Policy should reward investment in technology to maximize use of transmission infrastructure for renewables. Such policies should recognize that wind generation is a relatively poor resource for capacity and that creative use of technology may optimize use of transmission. Regulatory and contractual practice should allow technologies such as real-time line ratings, controls that manage output from multiple intermittent renewable resources, local short-term forecasting, and other non-standard approaches to balance renewable energy delivery with transmission infrastructure costs.

3.3.3 Renewable Generation Technology, Policy, and Practice

With significant levels of intermittent renewable generation, operation may be challenging at extremely light load levels, under a constrained transmission grid, or with high wind volatility. Under these conditions, renewable generation must participate in overall grid control. The following recommendations are specific to renewable technology, and are aimed at assuring that intermittent renewables play an active and positive role in the secure and economic operation of the grid:

Curtailment. Under the rare occasions of coincident minimum load, high wind generation and low conventional hydro flexibility, it must be possible to curtail intermittent renewables. The grid operator should have the ability to order such a reduction in production. Regulatory and contractual arrangements for intermittent renewables should be structured such that curtailments are recognized, allowed and appropriately compensated. Ramp rate controls could also be considered.

Ancillary Services. Intermittent renewables may be able to provide ancillary services that are both valuable and economic under some operating conditions. For example, wind generation can provide frequency regulation. Such functionality is a requirement in some regions. Regulatory and contractual arrangements for intermittent renewables should be structured such that providing such services are recognized, allowed and appropriately compensated.

Forecasting. Successful and economic operation of the California grid requires wind and solar forecasting. This study verified substantial benefits from the use of state-of-the-art day-ahead forecasting in the unit commitment process. Substantial benefits are expected for improvements in both longer term (multi-day) and short-term (hours and minutes ahead) forecasting. Investment and policy must encourage development of high fidelity intermittent renewable forecasting for all intermittent renewable generation in the state.

Monitoring. The wind production profiles used in this study are based on historical weather data and sophisticated computer models. Recorded data from real operating experience will be invaluable in refining operating practice, performance and flexibility requirements. Time synchronized production and meteorological data from many plants will provide validation or correction of the trends and results predicted by this study. They will show the benefits and limitations of spatial diversity, meso-scale modeling, and various wind plant controls. It is recommended that California continue and expand, as necessary, programs to monitor, analyze and disseminate performance information relevant to grid operations and planning for intermittent renewables.

4.0 Conclusions

The IAP project is a comprehensive effort aimed at assessing the impact of increasingly higher levels renewables on the future California grid. Specifically, the IAP project focuses on transmission infrastructure and operations strategies necessary to accommodate 20% renewables in 2010 and 33% renewables by 2020. The efforts will help provide a vision of the "in-state future transmission grid" (infrastructure and operation services) and the mix of renewables and traditional generation resources. The IAP project also included reports on the historical operation and technical development of wind turbines on the California grid, and on the international experience with incorporating variable renewable energy technologies.

The IAP project included four scenarios: 2006 (2,100 MW of wind and 330 MW of solar); 2010 Tehachapi with 20% renewables (7,500 MW of wind and 1,900 MW of solar); 2010 Accelerated with 33% renewables (12,500 MW wind and 2,600 MW solar); and 2020 with 33% renewables (12,700 MW wind and 6,000 MW solar). Preliminary results were reported at public workshops held at the Energy Commission on August 15, 2006, and February 13, 2007. The final results are in the GE and DPC reports that are attached as appendices to this executive summary.

The principle conclusion is that California can incorporate the level of renewables assessed in the IAP project provided that appropriate infrastructure, technology and policies are implemented. This includes investment in transmission, generation and operations infrastructure; appropriate changes in operations practice, policy and market structure; and cooperation among all participants.

Organized by generation, transmission and renewable energy technology policy and implementation, several findings and recommendations were made and are discussed in more detail in the GE and DPC reports:

Generation Resource Adequacy

- A combination of in-state generating resources and power exchange agreements or capability should be pursued to allow operation to a minimum net load of between 18,000 to 20,000 MW.
- Pursuing generating resources with greater minimum turndown and diurnal start/stop capabilities; ensuring greater participation by loads and optimizing use of pumped storage hydro will also aid with integrating variable renewable energy generation.
- In-state generating resources should also be targeted for providing scheduling flexibility on an hourly basis. For light load conditions, total hourly scheduling flexibility requirements are smaller but the relative impact of variable renewables is greater. Maintaining or improving hydro flexibility and accessing generating

resources with faster start and stop capabilities will aid with hourly scheduling flexibility.

- For sustained, multi-hourly load increases and decreases, it is recommended that the California grid have the capability to meet a maximum morning load increase of 12,000 MW over three hours and a maximum evening load decrease of 14,000 MW over three hours.
- An increase of 10 MW/minute of load following is necessary to incorporate the levels of renewables studied as compared to the requirements for load alone. About 70 MW/minute of down load-following requirements is necessary during light load periods.
- California should consider allowing import and export scheduling to occur more frequently and at other times than on the hour.
- The impact of variable renewables on regulation is relatively modest (20 MW). Still, California should, at a minimum, maintain current level of regulation capability and consider other means of providing regulation besides conventional generation, such as flywheels or variable speed pumped hydro.
- While operational flexibility is valuable to the grid, it can impose significant costs and revenue reductions on generation providers. Expanded ancillary service markets, incentives and requirements may be necessary to overcome this problem.
- The IAP analysis did not include historical constraints such as long-term contractual obligations. New proposed contracts and existing long-term contracts up for renewal or subject to renegotiation should be reviewed with regards to increasing grid flexibility and adequacy.
- Increased competition from new resources, renewables or otherwise, may push marginally profitable generating resources out of business. Plant retirements should be projected, monitored and evaluated.
- California should measure, verify and catalogue the flexibility characteristics of individual generating resources.

Transmission Infrastructure

- Transmission planning to accommodate multiple wind plants should consider the spatial diversity of these plants. Wind plants in close proximity will typically require transmission capability to the aggregate rating of the plants, while wind plants further apart may require less transmission capability.
- Significant transmission investments are necessary to meet the 2010 and 2020 renewable targets. For the 2010 Tehachapi case, 74 new or upgraded transmission line segments are needed at an estimated cost of $1.2 billion. Most of these line segments (63) are needed to serve growing load. In addition, 31 new or improved transformers would be needed for an additional cost of $161 million.

- The 2020 case would require 128 new or upgraded transmission line segments, with just over half (66) needed to serve increasing load requirements. For just the 500 kV and 230 kV additions, an estimated cost would be $5.7 billion. In addition, 40 new or improved transformers would be needed at an estimated cost of $655 million.
- The transmission analysis suggests that wind variability may contribute to transmission congestion under certain renewable energy dispatch scenarios, and that transmission congestion patterns are more difficult to predict as the penetration of variable renewable energy resources increases.

Renewable Generation Technology, Policy and Practice

- Policy and regulatory and contractual practices to maximize existing use of transmission should be encouraged, such as real-time line ratings, local short-term forecasting, and controls that manage output from multiple variable renewable energy resources.
- Under rare circumstances of coincident minimum load, high wind generation, and low conventional hydro flexibility, curtailment of variable renewable energy generation may be necessary.
- Regulatory and contractual arrangements for intermittent renewables should be designed to allow and compensate for the provision of ancillary services such as frequency regulation.
- Wind and solar forecasting offers significant benefits in the multi-day, unit commitment and short-term (hours and minutes) time frames. Through policy or investment, high fidelity forecasting for all variable renewable energy generation in California should be conducted.

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Glossary

ACE	Area control error
AGC	Automated generator control
AMWCO	aggregate megawatt contingency overload
ATC	Available transfer capability
CABPS	California Bulk Power Storage
California ISO	California Independent System Operator
CERTS	Consortium for Electric Reliability Technology Solutions
COI	California Oregon Intertie
CO_2	Carbon dioxide
CPS2	Control Performance Standard 2
CPUC	California Public Utilities Commission
CS	Concentrating solar
CSP	concentrated solar power
CWEC	California Wind Energy Collaborative
DPC	Davis Power Consultants
DWR	Department of Water and Power
EAO	Electricity Analysis Office
Energy Commission	California Energy Commission
FERC	Federal Energy Regulatory Commission
GE	General Electric Energy Consulting
GE-MAPS™	General Electric's Multi-Area Production Simulation
GW	gigawatt
IAP	Intermittency Analysis Project
ICAP	installed capacity
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District

kV	kilovolt
LADWP	Los Angeles Department of Water and Power
LCOE	Levelized cost of energy
LVRT	Low voltage ride through
m/s	meters per second
MVA	megavolt amperes
MVAR	megavolt-amperes reactive
MW	megawatt
NERC	North American Electric Reliability Council
NO_x	oxides of nitrogen
NREL	National Renewable Energy Laboratory
OASIS	Open Access Same-Time Information System
PG&E	Pacific Gas and Electric Company
PIER	Public Interest Energy Research
PSH	Pumped storage hydro
PSLF	Positive Sequence Load Flow
PSS	power system stabilizer
PV	photovoltaic
QSS	quasi-steady-state
RA	rolling average
RAS	Remedial action schemes
RD&D	research, development and demonstration
RPS	Renewables Portfolio Standard
RTBR	Renewable Transmission Benefit Ratio
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
SGIP	Self Generation Incentive Program
SMUD	Sacramento Municipal Utility District

SO_x	oxides of sulfur
SVA	Strategic Value Analysis
UCAP	uniform capacity
VAR	voltage-ampere reactive
V-Reg	voltage regulation
WECC	Western Electricity Coordinating Council
w/m^2	watts per square meter
WTRL	Weighted Transmission Loading Relief factor

Appendix A: Intermittency Impacts of Wind and Solar Resources on Transmission Reliability

See separate publication number CEC-500-2007-081-APA

Appendix B: Impact of Intermittent Generation on Operation of California Power Grid

See separate publication number CEC-500-2007-081-APB

Appendix C: List of IAP Industry Participants

This project required cooperation from various industry stakeholders and represents a culmination of perspectives, data and willingness to openly share in the planning effort. The following organizations (listed alphabetically) were actively engaged in the IAP and project reporting process. Staff from the following organizations actively participated in monthly conference calls, team meetings, attended workshops and provided feedback on the scenario development for this effort.

AES SeaWest, Inc.
Beacon Power
Bonneville Power Administration
California Department of Water Resources
California Energy Commission
California Independent System Operator
California Public Utility Commission
California Wind Energy Association
Center for Energy Efficiency and Renewable Technologies
Consortium for Electric Reliability Technology Solutions
Crossborder Energy
Electric Power Group
Florida Power & Light Energy, LLC
Imperial Irrigation District
Independent Energy Producers of California
Los Angeles Department of Water and Power
National Renewable Energy Laboratory
Oak Creek Energy Systems
Oak Ridge National Laboratory
Pacific Gas and Electric Company
Sacramento Municipal Utility District
San Diego Gas & Electric Company
Southern California Edison Company
Utility Wind Integration Group