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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 10-05-006 Filed May 6, 2010

REPLY COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE
ON RESOURCE PLANNING ASSUMPTIONS - Part 2
(Long Term Renewable Resource Planning Assumptions) – Track 1

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July 16, 2010

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Pursuant to the California Public Utilities Commission's ("Commission's") Rules of Practice and Procedure and the *Administrative Law Judge's Ruling Revising the Schedule for the Proceeding and Regarding Staff's Proposals for Resource Planning Assumptions – Part 2 (Long Term Renewable Resource Planning Standards)* issued by Administrative Law Judge Victoria S. Kolakowski on June 22, 2010 ("ALJ's Ruling"), the California Energy Storage Alliance ("CESA")[1] provides the following reply comments.

As stated in its opening Comments[2], CESA is extremely appreciative of the White Paper published by the Commission on July 9, 2010[3] (attached as Appendix A), and looks forward to working very collaboratively with the Commission, Commission staff, and industry stakeholders over the coming weeks and months to further all of the demonstrably laudable analysis, conclusions, and recommendations it contains. At the same time, CESA also noted its appreciation of the California Independent System Operator's ("CAISO's") Discussion Paper

[1] The California Energy Storage Alliance consists of A123 Systems, Altairnano, Applied Intellectual Capital, Beacon Power Corporation, Chevron Energy Solutions, Debenham Energy, Deeya Energy, EAST PENN Manufacturing Co., Inc., Enersys, Enervault, Fluidic Energy, Ice Energy, International Battery, Inc., Powergetic, Prudent Energy, PVT Solar, Samsung SDI, SEEO, Suntech, SustainX Energy Storage Solutions, and Xtreme Power. The views expressed in these Comments are those of CESA, and do not necessarily reflect the views of all of the individual CESA member companies. http://www.storagealliance.org.

[2] *Comments of the California Energy Storage Alliance on Resource Planning Assumptions – Part 2 (Long Term Renewable Resource Planning Assumptions) – Track 1*, filed July 9, 2010. (Page 1).

[3] *Electric Energy Storage: An Assessment of Potential Barriers and Opportunities*, *Commission Policy and Planning Division White Paper,* July 9, 2010 (referred to herein as "Commission Whitepaper").

issued the day before on July 8, 2010[4] (attached as Appendix B). CESA's Comments were essentially written before publication of both papers, should therefore be read in that light.

CESA therefore hereby joins in the recommendation by several commenting parties[5] that a follow-up workshop should be scheduled, perhaps in advance of the anticipated Scoping Order. This would enable all stakeholders to digest the implications of the Commission's Whitepaper and the CAISO's Discussion Paper, and clarify a number of aspects of the Staff Proposal attached to the ALJ's Ruling that should be revised, particularly with reference to the optimum role of energy storage in the planning process.

Respectfully submitted,

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July 16, 2010

[4] Discussion Paper, *Renewable Integration: Market and Product Review*, July 8, 2009 (referred to herein as "CAISO Discussion Paper").
[5] Center for Efficiency and Renewable Technologies, Large-Scale Solar Association, and Southern California Edison.

APPENDIX A

California Public Utilities Commission

Electric Energy Storage:
An Assessment of Potential Barriers and Opportunities

Policy and Planning Division
Staff White Paper

July 9, 2010

This document can be found online at:
www.cpuc.ca.gov/PUC/energy/reports.htm

CALIFORNIA PUBLIC UTILITIES COMMISSION

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1 INTRODUCTION

California has the most aggressive suite of environmental polices in the nation, if not the world. California law currently requires that 20 percent of retail electricity sales come from qualified renewable resources.[1] The California Global Warming Solutions Act of 2006 ("AB32") requires that California reduce statewide greenhouse gas ("GHG") emissions to 1990 levels by 2020.[2] Additionally, an Executive Order issued by California Governor Arnold Schwarzenegger calls for an eighty percent reduction in emissions from 1990 levels by 2050.[3] The California PUC has established the most comprehensive set of energy efficiency policies and programs ever seen – appropriately named "California's Big Bold Energy Efficiency goals." California is currently undertaking an effort to retire, repower, or replace several thousand megawatts of aging, inefficient fossil fuel generation facilities in order to mitigate the environmental impacts of once-through cooling and to comply with the Clean Water Act.[4] Additionally, efforts are currently underway in the California Legislature to place into California law a separate requirement, independent of AB32, which would require load serving entities to meet 33% of retail electric sales from qualified renewable resources.[5] Thus, California policymakers face substantial challenges as they work to ensure reliable, efficient and environmentally sustainable energy for consumers at reasonable costs.

While California's energy and environmental goals are numerous and aggressive, the challenges presented by these various, and at times competing, initiatives are not insurmountable. However, the challenge of meeting all of these various goals requires policymakers, utilities and market participants to have a new approach and a new way of thinking about how to plan the state's electric energy system. In the past, planners relied chiefly upon large dispatchable fossil fuel generators to provide electric energy. The energy from these facilities was transmitted over the bulk transmission system and ultimately consumed by end-use customers. However, this model is changing. California's current energy policies mandate the development of new types of renewable and distributed generation resources, such as wind and solar. These resources by their nature are intermittent and cannot be directly dispatched by system operators to meet customer load. Thus, if the state wants to properly plan for these new types of resources, the historic model of electric system planning must be re-thought. Since operators of the electricity grid must constantly match electricity supply and demand, intermittent renewable resources are more challenging to incorporate into the electricity grid than traditional generation technologies. Intermittent renewable technologies cannot be scheduled to produce power in specific amounts at specific times, creating additional challenges and costs to resource procurement. Moreover, as more intermittent resources are deployed to meet increasing Renewable Portfolio Standards ("RPS") requirements, the operational challenges will become greater. Specifically, since planners cannot control when renewable generation will occur, the generation can often occur at times when there is little need

[1] California's Renewable Portfolio Standard (RPS) was established in 2002 under Senate Bill 1078 (Stats. 2002, Ch. 516, Sec. 3) and accelerated in 2006 under Senate Bill 107 (Stats. 2006, Ch. 464, Sec. 13,).

[2] AB 32 (Stats. 2006, ch. 488, effective September 27, 2006)

[3] Governor Arnold Schwarzenegger, Executive Order S-3-05, June 1, 2005. Available at: http://gov.ca.gov/executive-order/1861/

[4] *See*, Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling. Adopted May 4, 2010. Available at: http://www.waterboards.ca.gov/water_issues/programs/npdes/docs/cwa316may2010/otcpolicy_final050410.pdf.

[5] California's energy agencies have already established a 33% RPS as a policy goal, but currently lack statutory authority to enforce penalties for non-compliance.

for that power. However, a promising new set of Electric Energy Storage ("EES") technologies appear to provide an effective means for addressing the growing problem of reliance on an increasing percentage of intermittent renewable generation resources.

In the past, it was difficult, if not impossible, to store large amounts of electricity. There were two main barriers: economic (too expensive) and technological (inefficient, impractical). Recent advancements have been achieved and certain storage technologies have progressed through successful pilot and demonstration phases. As such, these technologies are poised to become commercially viable. EES offers California multiple economic and environmental benefits. By utilizing EES technologies to store intermittent renewable power, the state may reduce greenhouse gas emissions from carbon-based electricity production, avoid the need to build expensive new transmission lines and power plants to meet peak energy demand, increase system reliability and generate economic activity through the manufacturing and operation of these EES technologies.

As valuable as adding storage could be for California's power grid, many EES technologies are still early in their development, and existing commercial projects are in relatively short supply worldwide. As a result, EES faces several regulatory obstacles because of the lack of familiarity that regulators have with the various EES technologies. Regulators are uncertain how EES technologies should fit into the electric system, in part because EES provides multiple services such as generation, transmission and distribution. Furthermore, regulators do not yet know how EES costs and benefits should be allocated among these three main elements of the electric system.

California policymakers support the development of EES because it can provide an advantageous strategy for meeting the state's long-term clean energy goals while maintaining system reliability. However, relatively little information about EES costs and benefits is available to form a rational basis for policy action. The purpose of this paper is to identify for policymakers the opportunities for and barriers to the development and deployment of EES technologies throughout California's electricity system.

2 DEFINITION OF ELECTRIC ENERGY STORAGE

EES uses forms of energy such as chemical, kinetic, or potential energy to store energy that will later be converted to electricity. Such storage can provide several basic services: supplying peak electricity demand by using electricity generated during periods of lower demand, balancing electricity supply and demand fluctuations over a period of seconds and minutes, and deferring expansions of electric grid capacity (including generation, transmission and distribution elements).[6] One of the major conundrums facing policymakers and industry is the lack of a single, authoritative definition of electric storage. This lack of definition hampers efforts to overcome barriers to the widespread development and deployment of storage on the grid.

For the purposes of this paper, storage can be defined as: a set of technologies capable of storing previously generated electric energy and releasing that energy at a later time. EES technologies may store electrical

[6] Pew Center on Global Climate Change, *Energy Storage*. Available at: http://www.pewclimate.org/technology/factsheet/EnergyStorage

energy as potential, kinetic, chemical, or thermal energy, and include various types of batteries, flywheels, electrochemical capacitors, compressed air storage, thermal storage devices and pumped hydroelectric power.

3 DESCRIPTION OF ELECTRIC ENERGY STORAGE TECHNOLOGIES

EES technologies come in many forms. Some technologies have existed for decades (batteries, pumped hydro), so the concept of electric energy storage is not new. Advances in materials, electronics, chemistry and information technology have resulted in a number of newly emerging storage technologies; these new technologies have the potential to significantly reduce the overall costs on a broader scale.

EES can encompass a diverse range of categories, including – mechanical, thermal and chemical storage. Each of these broad categories has a unique set of parameters to measure cost and performance. This section describes some of the technologies currently available or under development; it is not intended to be an exhaustive list of existing or potential EES technologies.[7]

Pumped Hydro:[8] Pumped hydro storage uses low-cost electricity generated during periods of low demand to pump water from a lower-level reservoir (e.g., a lake) to a higher-elevation reservoir. The water is released to flow back down to the lower reservoir while turning turbines to generate electricity, similar to conventional hydropower plants. Pumped hydro storage can be constructed on a large scale with capacities of 100-1000s of megawatts ("MWs") and discharged over long periods of time (4 to 10 hours).

Compressed Air:[9] Compressed air energy storage ("CAES") plants use electricity to compress air into a reservoir. The high pressure air is released from underground and used to help power natural gas-fired turbines. The pressurized air allows the turbines to generate electricity using significantly less natural gas. The compressed air can be stored in several types of underground media (*i.e.*, reservoirs) including porous rock formations, depleted natural gas/oil fields, and caverns in salt or rock formations.

Batteries:[10] Several different types of large-scale rechargeable batteries can be used for EES including sodium sulfur ("NaS"), lithium ion, and flow batteries. Batteries have the potential to span a broad range of energy storage applications. Battery systems for electricity storage use the same principles as batteries used,

[7] For each technology listed, we presume that the energy is stored at times when demand (and therefore price) is low and released at a time when demand (and prices) are relatively higher. This assumption is not intended to preclude a situation where EES is used to store energy for reliability purposes that might be diconnected from price/demand considerations.

[8] "The Potential of Wind Power and Energy Storage in California," Diana Schwyzer, Masters Thesis for Energy and Resources Group at UC Berkeley. November 2006. p. 33.

[9] "New Utility Scale CAES Technology: Performance and Benefits (Including CO2 Benefits)," by Robert B. Schainker (EPRI), Michael Nakhamkin (ESPC), Pramod Kulkarni (CEC) and Tom Key (EPRI). Available at http://www.energystorageandpower.com/pdf/epri_paper.pdf

[10] Descriptions of batteries, flywheels, SMES and electrochemical capacitors from "Challenges of Electricity Storage Technologies: A Report from the APS Panel on Public Affairs Committee on Energy and Environment," May 2007. http://www.aps.org/policy/reports/popa-reports/upload/Energy-2007-Report-ElectricityStorageReport.pdf.

for example, in automobiles, but in much larger and higher power configurations. EES systems based upon batteries can be portable; since batteries are a known technology, the utility industry is generally familiar with them.

Thermal Energy Storage:[11] There are two types of thermal energy storage ("TES"): TES applicable to solar thermal power plants and end-use TES. TES for solar thermal power plants consists of a synthetic oil or molten salt that stores solar energy in the form of heat collected by solar thermal power plants to enable smooth power output during daytime cloudy periods and to extend power production for 1-10 hours past sunset. End-use TES stores electricity through the use of hot or cold storage in underground aquifers, water or ice tanks, or other materials and uses this energy to reduce the electricity consumption of building heating or air conditioning systems when needed.

Flywheels: A conventional flywheel stores energy as the kinetic energy of a massive disk spinning on a metal shaft. To retrieve stored energy from the flywheel, the process is reversed with the motor acting as a generator powered by the braking of the rotating disc. The amount of energy stored depends upon the linear speed of rotation and the mass of the disk. Short discharge time flywheels are suitable for stabilizing voltage and frequency, while longer duration flywheels may be suitable for damping load fluctuations.

Ultracapacitors: Ultracapacitors are electrical devices that consist of two oppositely charged metal plates separated by an insulator. The ultracapacitor stores energy by increasing the electric charge accumulation on the metal plates and discharges energy when the electric charges are released by the metal plates. Generally, capacitors are suitable for short-duration applications like providing backup power during brief interruptions. Advanced capacitors are useful for stabilizing voltage and frequency.

Superconducting Magnetic Energy Storage: Superconducting magnetic energy storage ("SMES") consists of a coil with many windings of superconducting wire that stores and releases energy with increases or decreases in the current flowing through the wire. Energy is added or extracted from the magnetic field of the inductor by increasing or decreasing the current in the windings. At steady state, the superconducting windings dissipate no energy, and energy may be stored indefinitely with low loss. The main parts in a SMES are motionless, which results in high reliability and low maintenance. However, superconductors also require refrigeration systems that introduce energy losses and do contain moving parts. Power can be discharged almost instantaneously with high power output for a brief period of time with less loss of power than for other technologies.

4 COSTS OF ELECTRIC ENERGY STORAGE TECHNOLOGIES

There are a number of factors that influence the cost of an EES technology. Storage tends to be an application-specific resource and therefore the costs (and benefits) can vary greatly. One of the complications in developing detailed cost estimates of EES technologies is that the costs of a given technology are greatly influenced by the particular application in which that technology is deployed. Thus, any generalized cost estimates are of questionable value. While a detailed analysis of the costs of specific EES technologies is

[11] Pew Center on Global Climate Change, *Energy Storage*. Available at: http://www.pewclimate.org/technology/factsheet/EnergyStorage

beyond the scope of this paper, included below is a brief overview of some of the main cost drivers of EES technologies.

Estimating the total installed cost of a given EES technology cannot be accomplished without advance knowledge of a number of key factors. An EES system's size varies on two dimensions: power (how much electricity can be discharged at one time) and energy (how many hours can be discharged continuously). EES system costs are impacted by system efficiency (how many useable kWh can be discharged compared to the amount charged). The frequency of how often and deeply the system is discharged also impacts costs. All of these factors (size, efficiency, and frequency) mean that an EES technology's cost cannot be meaningfully estimated independently of the way in which it is used.

The lifecycle cost of an EES system is made up of two basic components: capital costs and operating and maintenance ("O&M") costs. The most commonly used metric to estimate the lifecycle costs that incorporates these two factors is $/kW-yr, or how much a kW of capacity costs to own and operate for one year. Public analyses have estimated capital costs to a certain extent, while O&M cost estimates are more difficult to find. EES O&M costs include the cost of buying the energy used to charge the system, fixed costs that do not depend on how much or often the system is used, and variable costs, the bulk of which are replacement costs.

Ultimately, however, the actual cost of a given EES application is not as important a metric as a well formulated cost effectiveness measure that appropriately accounts for the full range and types of costs and benefits that EES can provide to the overall system. The challenge for policymakers is how to develop a cost-effectiveness evaluation for EES that does not favor one technology over another while recognizing the various costs and benefits that EES provides.

5 BENEFITS OF ELECTRIC ENERGY STORAGE TECHNOLOGIES

The benefits of EES often cross the traditional boundaries of generation, transmission, distribution, and at times, load which make analysis difficult. As noted above, the ability of EES technologies to provide multiple services, and thus, varying benefits leads to confusion and uncertainty about how energy storage should be regulated and valued. For the purposes of this paper, the benefits are categorized as economic and operational.[12]

One complicating factor is that oftentimes the quantification of benefits will depend upon the particular application of storage. This means that there is no "one-size-fits-all" approach to valuing the benefits that EES will provide. Another complicating factor is that the value of a single EES installation is often divided between the owner of the EES system, utility shareholders, and utility ratepayers, such that it is difficult for one set of stakeholders to capture enough of this value to outweigh the technology's costs, even if all these value streams are properly priced in the relevant markets.

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[12] These two categories are not necessarily mutually exclusive. Therefore, several of the operational benefits also will provide a certain amount of economic benefits.

5.1 ECONOMIC BENEFITS

Energy bill savings from shifting demand to off-peak times: EES enables customers to change when they draw power from the grid to meet their demand. For customers on dynamic rates (*i.e.*, those who pay more for power during times of higher demand on the grid), EES allows energy arbitrage opportunities whereby the EES system charges when the cost of energy is low and discharges when the cost of energy is high.

The economic value of this load-shifting varies depending on the customers' load shape and tariff, as well as the timing and frequency of when the load is shifted. Many commercial and industrial power customers in California have tariffs that consist of an energy charge, which is based on how many kilowatt-hours of energy have been used in a given time period, and a demand charge, which is based on the size of maximum demand within one month. Use of EES can reduce energy charges if the spread between on-peak and off-peak time of use rates is large enough. Even larger savings could come from reduced demand charges, if EES reliably reduces the size of the customer's maximum demand peak in a given month. Customers with photovoltaic ("PV") systems can use an EES system to mitigate the intermittency of their PV panels' power production, thereby acting as a back-up to the PV system's output and ultimately reducing the customer's demand charge.

Profits from selling EES resources into ancillary services and/or energy markets: If market rules enable EES owners to sell into ancillary services markets or wholesale energy markets, they can profit from these services. [13] For example, third-party owners of flywheels are currently seeking to sell into CAISO regulation markets.

Lower future EES costs as market matures: The EES market is currently an emerging market. Costs will be lowered in the future as a result of learning-by-doing, developing economies of scale and conducting additional research and development. Increased demand will spur EES manufacturers, integrators and installers to become more efficient which should further reduce future costs. Policymakers will need to consider these market transformations when determining the value, if any, of public investment.

Employment and other economic growth if industry locates in California: As more storage is deployed, new jobs could be created in manufacturing and installation, boosting the state's economy and providing a new source of tax revenue.

5.2 OPERATIONAL BENEFITS

Improved power quality: Some commercial and industrial customers' manufacturing or other processes are harmed if their power varies in frequency and voltage. EES can serve to eliminate these power quality inconsistencies.

Reliable and cleaner back-up power: EES technologies can provide customers with electricity for a period of hours when utility power is not available. While economics prevent EES being used as a long-term back-up (*i.e.*, for multiple days at once), EES can provide a source of back-up power for shorter outages.

Reduced need for peak generation capacity: By allowing customers, utilities or power generators to store energy off-peak and discharge on-peak, storage provides an alternative to the construction and operation of

[13] The ability to sell into ancillary services markets is discussed in more detail in the section on societal benefits

new generation and reserve capacity. Peak demand growth is a major concern for California electricity planners, exacerbated by the fact that populations in the hotter central and southern parts of the state are growing fastest. The value of the avoided cost of peak generation capacity will continue to increase as peak demand grows and as carbon emissions become more expensive.

More efficient use of renewable and other off-peak generation: California's clean energy and GHG emissions reduction goals require a large increase in wind and other renewable electricity generation in coming decades. Wind in California tends to blow most strongly at night, and the CAISO predicts a serious mismatch of load and generation in the off-peak hours of 11 pm to 6 am, including as much as 3000 to 5000 MW of excess off-peak capacity. Rather than forcing renewable generators to curtail off-peak production, EES can allow excess wind and other off-peak energy to be stored and used during high demand times.

Reduced need for transmission and distribution capacity upgrades: EES can be used to maximize existing transmission and distribution ("T&D") resources. EES can shift demand off-peak, delaying the need for new T&D upgrades that would have been needed to accommodate growth. EES located at the transmission substation level can be dispatched by the utility to meet peak demand in a transmission-constrained region with power charged off-peak. The value of T&D upgrade deferral varies greatly by location and is driven by the population density of the area, terrain, geology, weather, and the type and amount of T&D equipment involved.

Transmission support and congestion relief: EES can be used to improve T&D system performance by alleviating problems like voltage sag and unstable voltage. In addition, EES can help to avoid transmission congestion by discharging in congested areas at times of peak demand. For this purpose EES can be located either at the customer location or at an appropriate location on the transmission or distribution system. As noted just above in connection with T&D upgrade deferral, the range of values for T&D congestion relief between locations will be large.

Increased and improved availability of ancillary services: Ancillary services are services necessary to support the transmission of energy from generation resources to consumers, while maintaining the reliable operation of the transmission system. There are two primary types of ancillary services sold in California, both of which could be provided by EES: frequency regulation, which ensure the grid operates within an allowable range of interconnection frequencies, and operating reserves, which ensure that more energy can be added to the system within a short period of time to meet unexpected increases in demand or reductions in supply. EES technologies are capable of providing regulation services as well as operating reserves.

Lower GHG and other emissions: EES can reduce emissions by shifting on-peak energy use to off-peak periods. In California, relatively little baseload power comes from coal and much comes from hydroelectric and nuclear power, such that off-peak generation generally has a cleaner emissions profile than largely gas-fired peak power. However, as renewables like wind increase as a percentage of the off-peak power mix, the emissions benefits of EES will continue to grow.

EES is also a lower-emissions alternative for providing ancillary services. A study by KEMA found that regulation provided by a 20 MW flywheel EES system created less than half the GHG emissions of equivalent regulation from a combined cycle gas turbine and less than three quarters of the emissions of a pumped hydro plant providing equivalent regulation.[14]

6 RECOMMENDATIONS

EES represents a valuable potential addition to the resource mix available to meet California's various energy and environmental goals. While EES has many different applications and benefits, widespread deployment and utilization of EES technologies face numerous commercial and regulatory barriers. As a result, if policymakers want to increase the amount of EES in operation throughout California's electricity system they must take action. The following policy recommendations highlight potential actions that California's regulatory authorities could undertake to facilitate the deployment of EES into California's electricity system.

Prior to opening a formal rulemaking the CPUC should consider convening a symposium to explore the best options for EES deployment. The symposium would help the Commission narrow the focus of a potential rulemaking by helping to define the ultimate goal(s) of EES deployment.

The CPUC should conduct a rulemaking to develop a comprehensive set of policies to remove barriers to the deployment of EES technology in California. The deployment of EES technologies will create a variety of benefits and costs for California ratepayers that reach across the Commission's traditional program silos, such as energy generation, demand response, resource adequacy, renewables development, etc. A centralized, coordinated rulemaking addressing storage will avoid unnecessary duplication and potentially conflicting policy development. Top priorities in the rulemaking should be:

1. Define the goals of increased deployment of EES within California's electrical energy system.
2. Determine what the potential operational uses are for EES.
3. Develop a cost-benefit methodology for EES and use it to define, quantify and monetize the full range of EES costs and benefits.[15]
4. Compare the costs and benefits of various types of EES with those of other load-shifting and emissions reduction strategies (including energy efficiency, demand response, and renewable energy procurement), in order to determine how ratepayer funds can be optimally committed.
5. Determine the mechanism(s) by which an EES facility can recover its costs, including when the facility is being used for multiple purposes.
6. Develop a methodology to determine a Resource Adequacy ("RA") value for EES, thus enabling load serving entities to meet part of the requirements under the RA program with storage resources.
7. Streamline the siting and interconnection rules for both distributed and utility scale EES projects.
8. Explore whether the natural gas industry, which has relied upon storage products and services for decades, could provide some insight as to how best to incorporate EES into the electric system.
9. Consider developing incentives for EES, which could include:

[14] Richard Fioravanti and Johan Enslin. "Emissions Comparison for a 20 MW Flywheel-Based Regulation Plant." KEMA, January 2007.

[15] A cost benefit analysis for energy storage may need to consider costs and benefits that may be outside the jurisdiction of the CPUC.

a. An EES procurement standard and/or feed-in tariff(s).[16]
b. Increased utility rates of return for EES investment *(i.e.*, utility ownership).
c. Develop a methodology to allow utilities to earn an incentive rate of return on power purchase agreements signed with EES developers.[17]
d. Increased and coordinated research, development and deployment programs with appropriate levels of funding for EES technologies.

Consider explicitly placing EES within the state's energy resource loading order and require utilities to incorporate EES in their integrated resource planning processes. California's Energy Action Plan established a "loading order" to meet the future energy needs of the state. Specifically including EES in the loading order would demonstrate the importance of deploying cost-effective storage resources throughout the state. In addition, the Commission could consider requiring that all resource procurement processes conducted by utilities explicitly allow EES to participate.[18]

Create and facilitate a California Energy Storage Collaborative. All segments of industry would benefit from a concerted effort to share ideas, data and experiences related to EES. The CPUC should convene an Electricity Storage Working Group to provide an opportunity for representatives from CEC, CAISO, and FERC as well as from the utility, EES manufacturer and installer industries (among others) to meet and collaborate on an ongoing basis. A product of this collaborative could be an established set of "best practices" relating to siting, permitting, safety, and cost allocation.

Require all IOU customers, including residential customers, to move to dynamic retail rates. Current rate structures do not create an incentive for consumers to make efficient decisions about their energy consumption. Unless customers are charged accurate prices for power, these inefficient decisions about how much power to use and when will continue. Dynamic rates will incent more active participation in energy management and consumption by all consumers which could lead to increases in energy efficiency and other demand response strategies as well as greater EES deployment.[19]

Encourage the CAISO to change ancillary service market rules to allow EES systems to more easily bid into regulation markets. Many stakeholders have suggested that the CAISO make two changes to its regulation market rules: (1) to allow EES to bid less than 1 hour of energy in capacity/RA and regulation markets; and (2) to reduce the minimum bid size in the regulation market to less than 1 megawatt.[20] The

[16] AB 2514 (Skinner), currently pending in the California state senate as of July 1, 2010, would require the CPUC to open a rulemaking to, among other things, consider an appropriate EES procurement mandate for load serving entities.

[17] See, Georgia Code Title 46. Public Utilities and Public Transportation Chapter 3A. Integrated Resource Planning § 46-3A-8.

[18] Alternatively, the Commission may determine that utilities should be required to conduct storage only procurement processes.

[19] AB1X (Water Code Sec. 80110, effective 2001), limited the ability of the PUC to implement dynamic rates for residential customers until the Department of Water Resources "has recovered the costs of power it has procured" to meet retail load on behalf of the Investor-Owned Utilities. SB 695 (Public Utilities Code Sec. 745(b), effective 2009), revised AB1x by setting specific dates as to when the PUC can implement default dynamic rates for residential customers. The statute states that the PUC "shall not ... (1)employ mandatory or default time-variant pricing, with or without bill protection, for any residential customer prior to January 1, 2013; (2) employ mandatory or default time-variant pricing, without bill protection, for residential customers prior to January 1, 2014."

[20] For example, during the CAISO's Market Design Initiatives stakeholder process, the CAISO proposed a 30 minute Ancillary Services product that would, amongst other things, potentially limit the need for the CAISO to use Exceptional Dispatch. In the CAISO's September 18, 2009 "Updated Catalogue of Market Design Initiatives," this was ranked as a "Low" priority with the potential to "reconsider the issue in the future if necessary." Available at

CPUC should consider making these and/or other recommendations to the CAISO with the goal of allowing EES projects to provide valuable regulation and capacity resources to the grid.

Integrate EES in transmission planning. Decisions regarding new transmission lines could be impacted by the deployment of EES and vice versa. Investment in EES could serve to defer or displace the need to build new transmission lines because EES is often less costly than building new transmission facilities. Alternatively, transmission build outs could factor into the location for EES deployment.

7 CONCLUSION

EES has the potential to enhance California's ability to effectively meet its many energy and environmental goals. EES can provide a number of benefits to the grid: it can provide emergency backup, reduce the need for peak generation capacity, provide ancillary services, facilitate demand response, reduce GHG emissions and help to integrate intermittent renewables.

Currently, EES technologies face a number of commercial, economic and regulatory obstacles. The major barrier for deployment of new storage facilities is not necessarily the technology, but the absence of appropriate regulations and market mechanisms that properly recognize the value of the storage resource and financially compensate the owners/operators for the services and benefits they provide. As a result, while many applications of storage are technologically feasible, they struggle to become commercially viable. California policymakers face numerous challenges in developing policies and programs that will facilitate the achievement of its goals. EES may provide policymakers with an additional opportunity to meet the state's long-term clean energy goals and maintain system reliability, while minimizing costs.

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http://www.caiso.com/2433/2433dda16ba10.pdf, at page 37. Such a product could also be used to incent a wider range of storage technologies to provide ancillary services.

APPENDIX B

California Independent

California ISO

Discussion Paper

Renewable Integration: Market and Product Review

July 8, 2010

Prepared by: California ISO

Discussion Paper
Renewable Integration: Market and Product Review

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1 Introduction

In response to the renewable portfolio standard (RPS) and other state policy and regulatory directives, California is poised to rapidly increase the interconnection and integration of variable energy resources, primarily wind and solar generation, into its power system over the coming decade.[1] The key operational characteristics of such resources are the variability of their fuel sources and the uncertainty associated with forecasting their production. As such, integration of variable energy resources will require increased operating flexibility – additional ramp, load-following,[2] and ancillary service capability – from both generation and non-generation resources. There may also be higher frequency and magnitude of over-generation conditions. In addition to providing additional and possibly faster ramps, the existing generation fleet will also likely need to operate at lower minimum loads and provide more frequent starts, stops and additional cycling over the operating day.

With the redesign and technology upgrade of the ISO wholesale markets and operating systems implemented in 2009, along with additional changes being implemented in 2010-11, the ISO market is able to optimize the use of available system resources and generate prices for energy and ancillary services that reflect network and operating constraints. These design changes, along with proposed refinements to interconnection requirements[3] and the results from studies that simulate system operations and markets under higher renewable scenarios, give the ISO confidence that the existing system can integrate the additional renewable resources coming on-line over the next 1-2 years, if not more. But as the system achieves the currently required 20 percent RPS, expected in the 2013 timeframe,[4] and advances toward a 33 percent RPS, it is important to begin now to examine whether further changes to market design will be needed.

This discussion paper initiates a comprehensive, phased process to work with ISO stakeholders to identify and develop potential changes to wholesale market design, including market products and procedures, needed to accommodate the expected substantial increase in production by variable energy resources over the next decade. The ISO seeks stakeholder input to help prioritize such design changes over the coming years, given the schedule for ISO market enhancements that are already planned or underway. The ISO expects that any proposed design changes resulting from this initiative will support efficient spot markets as well

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[1] Variable energy resources is the term being used by the Federal Energy Regulatory Commission to describe renewable resources that have variable or intermittent production. Variable energy resources is thus used here as an equivalent term to "intermittent resources". Not all renewable resources eligible under renewable portfolio standards are variable energy resources. For example, geothermal, biogas and biomass resources generally follow fixed hourly schedules.

[2] Load following is used here to refer to the "net" load shape resulting when variable generation production is subtracted from load.

[3] See ISO filing to FERC for "Tariff Amendment to Modify Interconnection Requirements Applicable to Large Generators and Request for Waiver," available at http://www.caiso.com/27c7/27c7addb3a300.pdf.

[4] California Public Utilities Code Section 399 requires that the RPS objectives be achieved by 2010, with some accommodation for deferred compliance under specified circumstances. The California Public Utilities Commission has acknowledged that the 2010 deadline will not be met and that the 2013-14 time frame is more realistic. See California Public Utilities Commission, *RPS Quarterly Report (Q4 2009)*, at p.4, available at www.cpuc.ca.gov.

as forward contracting and investment decisions that reflect integration requirements, while ensuring reliable system operations.

The remainder of this paper is organized as follows. Section 2 provides background on the major state and federal policies that affect renewable integration. Section 3 reviews the results to date of the ISO's integration studies. Section 4 introduces the market design changes that may be needed to support renewable integration and raises questions for stakeholders. Section 5 summarizes the questions for stakeholder consideration and presents the schedule for this initiative.

2 Major State and Federal Policy Drivers

This ISO initiative will examine the market and operational requirements associated with the integration of variable energy resources in the context of the large number of state and federal energy and environmental policy goals that are concurrently affecting the power sector. California currently has a 20 percent RPS target, implemented by the California Public Utilities Commission (CPUC) for its jurisdictional utilities and by the California Energy Commission for municipal utilities. A 33 percent RPS by 2020 has been advanced in several ways. The California Air Resource Board's scoping plan for achieving the state's targets for greenhouse gas emissions reductions incorporates a 33 percent RPS, and Governor Schwarzenegger has also issued an executive order to that end.[5] The state legislature is currently considering legislation to require a 33 percent RPS. In 2010, most resource and transmission planning efforts in the State have been organized around a 33 percent RPS.

State policy makers are influencing renewable development and integration in California through a number of existing and proposed programs and regulations, including the rules for RPS eligibility and compliance, feed-in tariffs for renewables, subsidies and incentives for electric storage, and generation contracting requirements under long-term procurement planning. In addition, tightening greenhouse gas emissions constraints, limitations on air emissions credits, and the California State Water Resources Control Board's adopted policy concerning best technology available under Section 316(b) of the federal Clean Water Act for power plant cooling may determine whether some existing thermal plants continue to operate and the location and type of replacement resources.[6]

At the federal level, there is legislation under consideration that would impose a national RPS and restrict greenhouse gas emissions. Of particular import to this current market design initiative, is the Federal Energy Regulatory Commission's (FERC) recent notice of inquiry that seeks to ensure the removal of unnecessary barriers to transmission service and wholesale markets for variable energy resources and technologies that may assist in their integration.

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[5] See Executive Order S-14-08 at http://gov.ca.gov/executive-order/11072/ and Executive Order S-21-09 at http://gov.ca.gov/executive-order/13269/.

[6] California State Water Resources Control Board Resolution 2010-0062, available at http://www.swrcb.ca.gov/board_decisions/adopted_orders/resolutions/2010/rs2010_0020.pdf. This policy will not be effective until it is reviewed and approved by the California Office of Administrative Law pursuant to California Government Code § 11353. The resources affected by this policy provide important local capacity and ancillary services, and as such the potential loss of these resources is a relevant factor for the ISO to consider when preparing the power system for higher levels of renewable integration.

FERC does not propose to adopt rules that favor one type of supply source over another. Instead, it intends to 1) to ensure that rates for jurisdictional service are just and reasonable, reflecting the implementation of practices that increase the efficiency of providing service; and 2) prevent variable energy resources from facing undue discrimination (while maintaining system reliability in accordance with reliability standards). Numerous parties, including the ISO, have already submitted comments to this proceeding and the next step in the regulatory process would be the issuance of a Notice of Proposed Rulemaking.[7]

3 Operational Impacts and Interim Study Results

In the context of this significantly evolving policy landscape, the ISO has continued to evaluate the impacts that the integration of variable energy resources will have on its operations and markets and to explore effective ways to accommodate increasing amounts of such resources. To date, renewable integration has largely been managed by the ISO through additional forecasting improvements[8] and existing operational tools and market rules, including the Participating Intermittent Resource Program (PIRP). However, as the ISO examines the requirements of variable energy resource integration at the 20 percent RPS level and then the 33 percent RPS level, the ISO expects more significant operational impacts including:

- increased regulation requirements;
- increased load following requirements, perhaps requiring an additional commitment of reserves;
- greater frequency and magnitude of over-generation; and
- other changes in the operations of conventional units, such as increased starts and stops and unit cycling.

Over the past 2 years, the ISO, along with the various state agencies and some market participants, have conducted a series of studies and undertaken additional significant efforts to evaluate the alternative approaches to facilitate the integration of variable energy resources. This section first reviews the status of the ISO's operational studies and then explores particular operational impacts identified as having significant implications for market design.

3.1 Review of Operational Studies

The ISO's evaluation of operational and market design needs is based both on renewable resource development that is, at this time considered fairly certain, as well as alternative scenarios for further renewable resource development over the coming decade. In late 2007, the ISO published an initial study of operational requirements associated with an incremental 4,200 MW of wind development at Tehachapi (henceforth, 2007 study).[9] The core methodology for the study was a statistical approach that identified changes in ramp, regulation

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[7] The ISO comments are available at: http://www.caiso.com/2777/2777ac8636f20.pdf.

[8] CAISO, *Revised Analysis of June 2008 – June 2009 Forecast Service Provider RFB Performance,* March 25, 2010, available at http://www.caiso.com/2765/2765e6ad327c0.pdf.

[9] See CAISO, *Integration of Renewable Resources*, November 2007, available at: http://www.caiso.com/1c51/1c51c7946a480.html.

and load following requirements. The results were widely disseminated and have met with acceptance in the industry.[10]

The 2007 study did not examine operational requirements resulting from solar thermal or solar photovoltaic (PV) technologies. Nor did the study quantify the potential for renewable energy to cause over-generation conditions or examine in detail the ability of generation and non-generation resources to provide the required integration capabilities. Subsequent to the 2007 study, the ISO has undertaken several efforts to further develop its simulation tools and the scope of the analysis. Notably, the ISO has updated the statistical methodology used in the 2007 study to calculate regulation and load following requirements in order to consider solar technologies and the effect on the requirements of geographic diversity among the variable energy resources. The results shown in Tables 1 and 2 below reflect these updated methods.

The ISO has also worked with various entities to develop production simulation models[11] that can examine key features of renewable production, such as forecast uncertainty, while representing a large number of generation and network constraints. Interim results from production simulations for a 20 percent RPS scenario that considered incremental wind additions at Tehachapi were presented in early 2009.[12] However, the ISO more recently re-calculated the results using the new solar profiles and revised operational requirements that were completed over the latter half of 2009. The full set of updated 20 percent RPS simulation results will be available shortly.

In addition, in late 2009, the ISO launched a series of 33 percent RPS simulations through a working group with stakeholder representation. This effort, which includes both the statistical models discussed above and production simulations, is examining several CPUC scenarios that vary renewable resource portfolios in 2020, including a 20 percent RPS benchmark scenario.[13] Many aspects of the 33 percent analyses are completed, with full results expected to be released in stages over the next few months. Yet other 33 percent RPS renewable portfolios are being evaluated through the CPUC long-term procurement planning proceeding and the 2010 transmission planning processes conducted by the California Transmission Planning Group[14] and the ISO. These resource and transmission planning efforts will give further insight over 2010-2011 into the sequencing of renewable resource interconnection by location and type over the coming years, and it is likely that further operational analysis will be needed.

The ISO also continues to cooperate with State agencies and research entities to produce policy and operationally relevant studies and tools. One such study is a recent assessment of frequency response and regulation under 20 percent and 33 percent RPS

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[10] Makarov, et al., "Operational Impacts of Wind Generation on California Power Systems," *IEEE Transactions on Power Systems*, Vol. 24, No. 2, (May 2009) at 1039.

[11] Production simulation refers to the use of large-scale computer-based models that incorporate a detailed representation of generation, demand and transmission over a wide region to simulate least cost commitment and dispatch.

[12] See presentations at http://www.caiso.com/2449/2449ea32303a0.pdf. These results were interim and will be updated in the final report.

[13] The CPUC report can be found at: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm.

[14] See http://www.ctpg.us/public/index.php.

conducted by KEMA; the ISO is still evaluating the application of the modeling tool used in that study.[15]

Despite not having the complete results of these various studies, the ISO believes that there is sufficient information available now and in forthcoming studies to launch this stakeholder process to examine market design changes to support the integration of variable energy resources. The market design process needs to be initiated earlier rather than later to ensure that decisions can be made on a timely basis. Moreover, some of the design changes can be evaluated prior to final study results.

The next sections provide further detail on some of the specific study results, both those that are already complete and those that are forthcoming.

3.2 Regulation Requirements

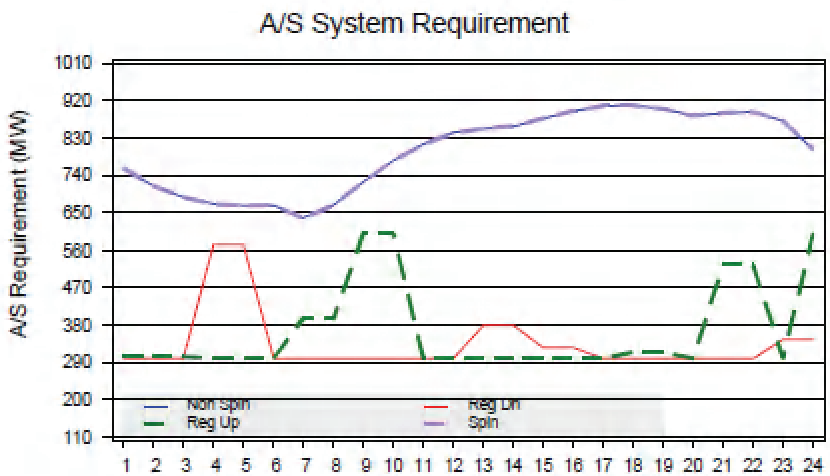
The ISO utilizes regulation for system balancing to manage the differences between generating units' response to dispatch instructions and actual load within a 5-minute period. In all its studies to date, the ISO has forecasted additional requirements for regulation, varying by hour and a substantial increase in particular hours, largely due to integration of variable energy resources. These requirements are shown for particular resource mixes in Tables 1 and 2.

The ISO has historically procured regulation reserves equal to an amount of approximately 1 to 1.5 percent of forecasted load on that a given day. To achieve this objective, the amount of upward and downward regulation procured varied from day to day between $\pm$ 375 and $\pm$ 500 MW as necessary to maintain compliance with NERC control performance standards, but until late 2009 remained fixed at a single quantity (MW) for all 24 hours of the operating day.

Because regulation is a function of the load and load forecast uncertainty, the same regulation requirement is not actually needed in each hour of the day. To further improve the efficiency of regulation procurement, on October 3, 2009, the ISO began to procure regulation on a variable basis by hour. An hourly variable regulation forecasting tool calculates the coincidental 10-minute peak requirement for regulation separately in the up and down direction for each hour based on changes in the demand forecast, generation self-schedule changes, and hourly inter-tie fluctuation. Figure 1 shows the hourly ancillary services system procurement requirements for June 26, 2010. The green dashed line is the regulation up requirement and the red line is the regulation down requirements. The blue and purple lines, which overlap, are the spinning and non-spinning requirements which represent approximately 7 percent of the load forecast.

[15] KEMA, Inc. 2010. *Research Evaluation of Wind and Solar Generation, Storage Impact, and Demand Response on the California Grid*. Prepared for the California Energy Commission. CEC-500-2010-010. Available at http://www.energy.ca.gov/2010publications/CEC-500-2010-010/CEC-500-2010-010.PDF.

Figure 1: Day Ahead A/S System Requirements for June 26, 2010



To evaluate future changes to the regulation requirement due to variable energy resources, the ISO has used the statistical methodology described above.[16] In deriving the 20 percent RPS results, the ISO used 2006 as a base year, and then incremented load and the production profiles of variable energy resources to 2012; the reader should note that at the time of the analysis, 2012 was the expected date for the 20% RPS. The same method is used for the 33% RPS simulations, in which load is incremented to 2020, with consideration of the effect of demand-side policies. In the most recent simulations, the 2012 case includes an additional 1,800 MW of solar resources, for a total of 2,203 MW, and an additional 4,100 MW of wind resources, for a total of 6,686 MW;[17] that is, the study models approximately 8,889 MW of variable energy resource capacity. The 2020 case represents the 33 percent RPS with the CPUC's 2009 "Reference Case" portfolio, which includes an additional 9,700 MW of solar resources (PV and solar thermal) and an additional 8,350 MW of wind resources over the base case.

The requirements calculated through these simulations are shown in Tables 1 and 2 by season. With respect to regulation, Table 1 shows the maximum hourly regulation capacity (MW) procurement requirements. Table 2 shows the simulated increase in the Regulation ramp rate (MW/min) requirements. Both of these requirements are roughly doubled from the base year to 2012, and then doubled again (or tripled in the case of ramp rate) by 2020. Actual requirements will vary by hour and there will be many hours with lower requirements than shown in the tables.[18] However, the system will need to be operationally ready to procure the highest requirements.

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[16] The gap between the 5 minute dispatch and the actual net load provided by regulation is evaluated using Monte Carlo simulation that utilizes the actual distribution of load, wind and solar forecast errors.

[17] The 2007 study did not explicitly model solar and only assumed about 1,000 MW of solar resources on the system.

[18] The hourly results will be presented in the forthcoming 20% operational study. For prior hourly regulation estimates based on incremental wind resources, see CAISO, *Integration of Renewable Resources*, November 2007, pp. 79-80.

The ISO has also analyzed the impact of different technologies on the regulation requirement. For example, wind is anticipated to cause additional regulation procurement primarily in the high wind production and high wind ramp hours (morning and evening). Solar is expected to cause additional regulation procurement primarily in the evening ramp down period. More detail on the requirements by technology will be available shortly.

3.3 Load Following Requirements

Load following is the incremental or decremental energy that the ISO dispatches in real-time on a 5-minute basis to address the difference between the final (hour-ahead) schedule going into the operating hour and the very short-term forecast (5-10 minutes ahead) of actual load. Load-following capability is provided by the real-time energy bids of dispatchable generation resources already committed, along with any available quick start generation resources. The ISO expects that in the future non-generation resources will play a greater role in this function. There is no explicit load-following product in the current ISO market, but as described here, a load-following reserve could possibly satisfy an operational need when the intra-hour variability due to variable generation exceeds the total incremental and decremental capability provided by the bids of dispatchable conventional generation and other quick start capacity.

The load-following results shown in Tables 1 and 2 use the same modeling assumptions as the regulation results discussed above. The result shown is for the maximum load-following hourly requirement by season; again, the actual requirements will vary by hour and there will be many hours with lower requirements than shown in the tables.[19] Since load-following is evaluated on longer time-frames than regulation (i.e., between the hour-ahead schedule and each 5 minute interval within the hour), forecast error plays a larger role in determining the result than minute to minute variability.

Whether the load following requirements shown in the tables (or those for interim periods) require additional procurement of existing reserves or of a new type of reserve product is a function of 1) whether the system can meet this new requirement through the real-time energy market alone and 2) whether the market revenues in the absence of a new product or some other source of additional revenue are sufficient to incent adequate market participation by the units that can provide the needed flexibility. With regard to the first issue – i.e., whether the system can follow load *without* any additional procurement of reserves or developing new ancillary services products – the ISO has evaluated this question through production simulations using various approaches. To date, these simulations have not yet demonstrated that the real-time energy market itself will be unable to provide the load following capability under a 20 percent RPS; however, the 33% RPS simulations have found that additional non-contingency reserves will be necessary to support load following. The second issue, whether the market revenues are sufficient to incent adequate market participation, will require further assessment and discussion in this process (and other concurrent ISO initiatives, such as that addressing backstop capacity procurement).

[19] The hourly results will be presented in the forthcoming 20% operational study. For prior hourly load following estimates based on incremental wind resources, see CAISO, *Integration of Renewable Resources*, November 2007, pp. 74-75.

Table 1: Expected Increase in Regulation and Load-Following Capacity (MW) Requirements

	Spring			*Summer*			*Fall*			*Winter*		
	2006	**2012**	**2020**	**2006**	**2012**	**2020**	**2006**	**2012**	**2020**	**2006**	**2012**	**2020**
Maximum Regulation Up Requirement (MW)	277	502	1,135	278	455	1,144	275	428	1,308	274	474	1,286
Maximum Regulation Down Requirement (MW)	-382	-569	-1,097	-434	-763	-1,034	-440	-515	-1,264	-353	-442	-1,076
Maximum Load Following Up Requirement (MW)	2,292	3,207	4,423	3,140	3,737	4,841	2,680	3,326	4,565	2,624	3,063	4,880
Maximum Load Following Down Requirement (MW)	-2,246	-3,275	-5,283	-3,365	-3,962	-5,235	-2,509	-3,247	-5,579	-2,424	-3,094	-5,176

Table 2: Expected Increase in Regulation and Load-Following Ramp Rate (MW/Min) Requirements

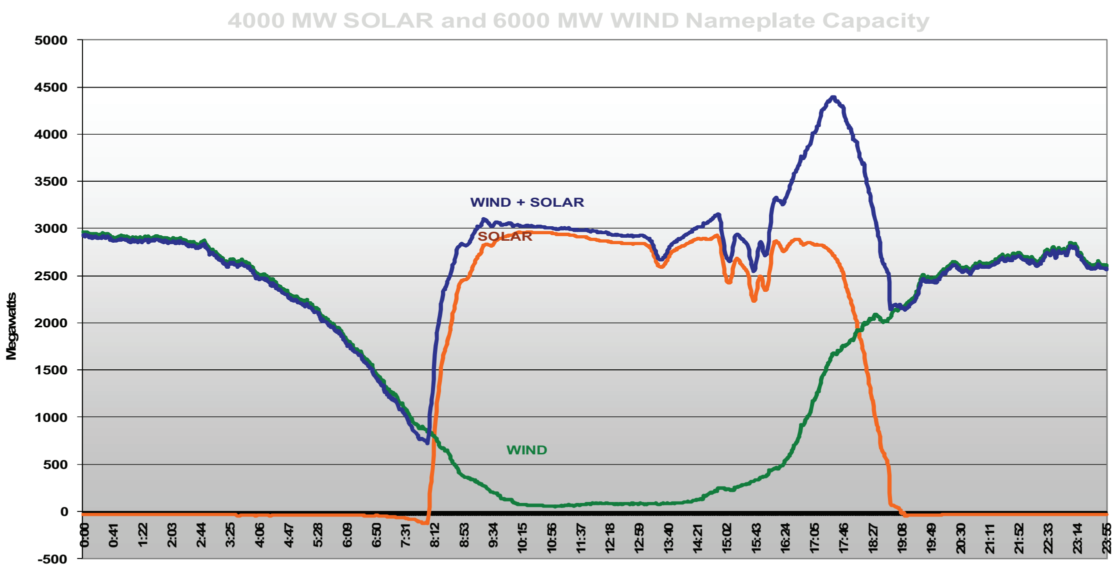
	Spring			*Summer*			*Fall*			*Winter*		
	2006	*2012*	*2020*	*2006*	*2012*	*2020*	*2006*	*2012*	*2020*	*2006*	*2012*	*2020*
Maximum Regulation Ramp Up Rate (MW/Min)	67	122	447	75	118	528	70	114	472	73	107	344
Maximum Regulation Ramp Down Rate (MW/Min)	-66	-90	-310	-76	-97	-300	-72	-90	-301	-79	-90	-303
Maximum Load Following Ramp Up Rate (MW/Min)	150	168	325	166	194	313	147	181	324	143	165	296
Maximum Load Following Ramp Down Rate (MW/Min)	-138	-162	-451	-145	-169	-434	-134	-167	-438	-158	-198	-427

3.4 Changes in Commitment and Dispatch of Conventional Generation

Renewable integration will likely result in significant changes over time to the operation of the conventional generation fleet, due to the operational characteristics of variable energy resources. When not controlled through dispatch, variable energy resource plants can have very steep ramp rates as compared to the more gradual ramp rates for conventional fuel source resources. Per the NERC Integration of Variable Generation Task Force report, some variable energy resource generators can change output by ±70 percent in a time frame of two to ten minutes, many times per day.[20]

Ramp is obviously an inherent property of regulation and load-following. The statistical methodology used in the operational studies includes an algorithm to calculate generic ramp rate requirements over the time period being analyzed. At certain times of day, the ramps induced by the combination of wind and solar production will become quite extreme and will recur daily. Figure 3 below, which is based on simulated data, provides an example of ISO ramping challenges at around 20 percent RPS due to wind and solar production. The chart shows steep ramps up and down up to 2,000 MW several times throughout the operating day. These steep ramps will impose additional load following requirements on the ISO system. The green line shows anticipated ramping from approximately 6,000 MW of nameplate wind generation. The orange line shows the forecasted ramping of approximately 4,000 MW of nameplate solar generation. The blue line represents the combined ramp of both wind and solar or the forecasted total ramp from renewable resources.

Figure 2: Example of Increased Ramps Expected by a 20 percent RPS



The production simulations being undertaken are measuring the changes in unit starts and stops, as well as unit cycling under different renewable resource portfolios. These simulations will assist the ISO and market participants in determining what additional investments may be needed to improve generation operating flexibility as well as to evaluate how changes in the energy and ancillary services revenues to the conventional generators over time may affect investment incentives.

In addition to these increasing daily ramps, higher renewable production will lead to incidences of more extreme ramps that are currently difficult to forecast. Both wind and solar resources can quickly reduce output under different meteorological conditions. For example, wind generators shut down when wind speeds exceed safe operating limits. As a result, a big storm front with high wind gusts can first result in a substantial spike in output, followed by the loss of hundreds of megawatts energy from wind generation over a short period of 10 to 20

[20] Available at http://www.nerc.com/files/IVGTF_Report_041609.pdf.

minutes. Also, wind shear conditions at a wind facility may result in the units going from zero to full output within a few minutes when the wind shear condition changes and the wind hits the turbines instead of passing above the units. The ISO is working with the Bonneville Power Administration and forecasting companies to improve the tools for predicting these types of energy spikes and to make this information available to ISO operators. Unlike the real-time "persistence" forecast, this forecast is designed to look at intra-hour variations of wind or solar supply, especially during severe weather events affecting variable energy resource production areas. To be ready for such situations, the ISO will need to ensure there is sufficient fast ramping capacity available from conventional and other resources to respond to these types of short-noticed extreme events.

3.5 Over-Generation

Over-generation occurs whenever there is more generation than load and the operators cannot move generators to a lower level of production. In California, over-generation is most likely to occur under the confluence of some or all of the following conditions: light spring load conditions with loads around 22,000 MW or less, all the nuclear plants on-line and at maximum production, hydro generation high production levels due to rapid snow melt in the mountains, long start thermal units on-line and operating at their minimum levels because they are required for future operating hours, other generation in a regulatory "must take" status or required for local reliability reasons, and wind generation at high production levels.

All other things equal, the increased volume of wind generation under a 20 percent and 33 percent RPS is expected to lead to higher frequency and magnitude of over-generation conditions than exist today. This appears to be confirmed in the production simulation results currently being completed.

4 Market Design Changes and Enhancements to Facilitate Renewable Integration

Based on the results of the operational studies, and the market changes being considered by other ISOs/RTOs, the ISO has identified the following key market design topics related to variable energy resource integration for consideration through this stakeholder initiative. Those market design topics are:

- Dispatch incentives for variable energy resources and potential reforms to the PIRP;
- Incentives for Day-Ahead participation by variable energy resources;
- Changes to Ancillary Service market products and pricing;
- Allocation of renewable integration costs, including ancillary services; and
- Implications for the markets of changes in prices due to renewable energy production.

Each of these areas is explored further in the following sections. The ISO seeks feedback from stakeholders on these proposed areas for market design evaluation and welcomes suggestions for other topics.

As noted above, the starting point for ISO and stakeholder assessment of additional needs is the existing market design. The market and system operational capabilities inherent in this design will be particularly useful in the next decade given that renewable integration will likely become the major driver of operational needs on the power system. Planned enhancements to the ISO markets in 2010-2011 – particularly convergence bidding, scarcity pricing of ancillary services, and rules to facilitate ancillary service provision by non-generation resources – will provide additional benefits for variable energy resource integration and improve overall market performance as the amount of variable energy resources increases. However, operational studies suggest that additional market design and procedure changes could be needed at around the 20% RPS level, or soon after, and hence a timely start to consideration of those changes is warranted.

4.1 Dispatch Incentives for Variable Energy Resources

Renewable resources designated as "use limited" resources[21] are currently not required to be available for economic dispatch in the ISO markets. However, several eastern ISOs and RTOs have moved recently to require submissions of such bids to reduce inefficient congestion management when variable energy resources are contributing to congestion, as well as to mitigate the negative price effects of over-generation.[22] In California, some load serving entities are now introducing curtailment rights into their RPS procurement contracts to mitigate such negative price impacts. To date, the ISO has not taken any measures to require submission of economic bids and in fact, as discussed below, the current rules under the PIRP create disincentives to submit such bids. In addition, the decremental bid floor is currently set to -$30/MWh which may not be sufficient to incent variable energy resources to decrement output economically.[23]

PIRP has played an important role in the development of the California renewable industry. In the early 2000s, the financial risk of being exposed to the wholesale market costs of energy imbalances[24] was seen as a significant impediment to wind resource development. To

[21] See tariff section 40.6.4.

[22] During extreme over-generation conditions, controllable generation and imports are at their minimum levels or are shut down, exports are maximized and the total net generation production still exceeds the system load. As such, the real-time energy prices typically go negative and the ISO, at times, literally pays adjacent balancing authorities to take the excess energy. Negative real-time energy prices are intended to provide the appropriate economic signals to provide incentives for curtailments.

[23] Tax credits for wind production along with other tax incentives guarantee these resources hourly payments for production of close to $37/MWh. The renewable energy production tax credit (PTC), currently at $21/MWh, is the primary federal incentive for wind energy and has been essential to the industry's growth. Additionally, wind project developers can choose to receive a 30% investment tax credit (ITC) in place of the PTC for facilities placed in service in 2009 and 2010, and also for facilities placed in service before 2013 if construction begins before the end of 2010.

[24] Because of the variability of wind, and to some degree, solar generation, these renewable resources experience significant differences between their scheduled and actual output, called an "imbalance." For example, based on its hour-ahead forecast, a wind farm with 120 MW of capacity could schedule to produce 100 MW over the hour between 8 am and 9 am, but then actually produce in a range between 50 MW and 120 MW in any particular 5-minute dispatch interval during the hour. When a wind resource is producing below its scheduled output, the ISO has to increase the output of other generation for that

address this issue, the ISO and market participants developed and implemented the PIRP in 2003 and 2004 with two primary aims: first, to obtain telemetry from wind resources for purposes of establishing a more accurate forecast for those resources; and second, to reduce the imbalance costs to those resources that provided the telemetry. Participating resources provide telemetry to a wind forecast vendor, which provides them with a day ahead advisory forecast and an hour-ahead wind schedule that the Scheduling Coordinator in turn submits to the ISO. Resources that follow these rules are charged a monthly averaged energy imbalance charge.[25] To be eligible for the PIRP settlement, they are not allowed to submit bids into the markets. The result to date is a small subsidy to the wind resources from the buyers in the real-time wholesale market (who pay for all real-time energy at its actual cost), and a large reduction in the financial risk of participation in the market for wind generators.

However, as the amount of wind and other variable renewable energy on the system increases, the market and operating implications of the difference between scheduled and actual output could become larger. The ISO is thus seeking stakeholder views on whether the current PIRP rules should be sustained at much higher levels of variable energy resource production or whether reforms to those rules are needed to improve the price-responsiveness over time of such resources. The ISO is also interested in whether other market rules changes are needed concurrently, such as a reduction in the decremental bid floor price currently set at -$30/MWh.

The ISO is also seeking stakeholders' perspective on whether variable energy resources should be encouraged to supply the ancillary services for which they would be eligible, such as regulation down. Currently, participation in the PIRP specifically excludes wind generators from submitting bids into the ancillary services markets.

4.2 Incentives for Day-ahead Market Participation by Variable Energy Resources

A design issue that is a component of PIRP reform, but also applies generally even in the absence of PIRP-type settlement rules, is the participation by variable energy resources in the day-ahead market. Under the current market design, variable energy resources, like all physical resources, can schedule voluntarily in the day-ahead market. However, there is no obligation to schedule, and any deviations from day-ahead schedules would be settled financially at real-time prices.[26] Consequently, the ISO has observed some limited day-ahead scheduling of wind resources, but little compared to expected next-day output.

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period; and when it is producing more than its scheduled output, the ISO may have to back down some other generation, which may also incur costs if that generation has already been paid for its output in the day-ahead market.

[25] Both the locational marginal price and the deviations from the schedule are averaged over the month.

[26] Although there is a day-ahead offer obligation for most conventional resources that provide resource adequacy capacity, there is no comparable requirement for variable energy resources that provide resource adequacy. In addition, there is no strong financial incentive for variable energy resources to schedule or offer their power into the day-ahead market because, as discussed above, under the PIRP most variable energy resources today are required to bid or schedule only in the real-time market through the bid submission process that occurs hourly in advance of the operating hour. Moreover, the current integrated forward market design does not provide the same protection from the financial consequences of real-time output variability as is currently available through the netting and averaging of imbalance charges for variable energy resource scheduling in the real-time market under the PIRP.

As the ISO sees additional variable generation at higher RPS levels, this lack of day-ahead scheduling may lead to day-ahead over-commitment of thermal generation (to minimize the risk of a supply shortfall) and a divergence of prices between the day-ahead and real-time market. Some other markets have established day-ahead scheduling obligations on wind resources. For example, ERCOT requires wind resource schedulers to provide a day-ahead schedule based on the forecasted output that the resource can exceed with an 80% confidence level. In contrast, several eastern ISOs and RTOs are reporting that convergence bidders (also called virtual bidders) are taking the day-ahead positions not currently being taken by variable energy resources, which indicates that such bidders have sufficiently accurate forecasts to take the financial risks. The ISO will not have comparable experience with both variable energy resources and convergence bidding until the latter is implemented in 2011, and hence cannot comment on the impact of such bidders in voluntarily addressing the lack of day-ahead variable energy resource participation.

Given the considerations above, the ISO seeks stakeholder views regarding what types of incentives should exist for day-ahead market participation by variable energy resources. The ISO is also interested in stakeholder views on how convergence bidders can be provided improved capabilities to participate. For example, improved day-ahead forecasts will substantially improve the ability of scheduling coordinators responsible for variable energy resources to participate in the day-ahead market, by reducing uncertainty about next-day production. Improved day-ahead forecasts could also help convergence bidders with their day-ahead bidding decisions, whether the forecasts are directly contracted by the convergence bidders or received via an ISO-mediated transfer of information.

Various other market design options have been aired to address the question of how to improve the incentives of variable energy resources to schedule day-ahead. For example, the FERC notice of inquiry asked explicitly whether the timing of the day-ahead market could be modified to facilitate participation by variable energy resources. The ISO day-ahead market, which consists of both the integrated forward market and residual unit commitment process, closes at 10:00 AM and results are posted by 1:00 PM. While it may be feasible to extend the deadlines for the various components of the day-ahead market, *i.e.*, integrated forward market and residual unit commitment, the ISO has not evaluated the feasibility of implementing such staggered deadlines and the overall impacts such changes would have on the markets, nor is it clear what objectives such changes would accomplish. To the extent specific proposals for changing the day-ahead market timeline are considered, the ISO is interested in stakeholder views on the impact this would have on the opportunities afforded to resources that bid into the day-ahead market, but do not clear the market, the impact on units with longer start-times, and demand response resources that benefit from participating in the day-ahead market precisely due to the advance time available to prepare for such response in the operating day. Modifications to the day-ahead market timeline may also create incongruities with inter-tie scheduling or natural gas procurement, which would also need to be considered.

Finally, in previous ISO meetings, some stakeholders have argued that to increase day-ahead scheduling by PIRP resources, the PIRP settlement rules should be extended to the forward markets. The ISO is interested in whether stakeholders continue to believe that this approach is viable in a high renewables scenario. Real-time deviations from hourly schedules are of a smaller scale than real-time deviations from day-ahead schedules. Hence, moving the PIRP rules into the integrated forward market would result over time in an ever larger proportion of the ISO day-ahead energy market not being exposed to full real-time price signals. As noted above, facilitating variable energy resources participation through minimizing exposure to imbalance costs (*e.g.*, under PIRP) should be balanced against the value of market price signals to guide efficient system operations. The ISO would like stakeholders to offer views on this trade-off – *i.e.*, financial risk management for variable energy resources *versus* efficient pricing for dispatch.

4.3 Changes to Ancillary Service Procurement and Market Design

As discussed above, higher levels of production by variable energy resources such as wind and solar resources will create additional ancillary service requirements. Some of these requirements can be met by adjusting the procurement of existing products, such as regulation; other requirements could require definitions and procurement of new products, such as a variable energy resource ramp-contingent reserve or a non-contingency load-following reserve. Ancillary service procurement requirements are also a function of many other factors that remain uncertain, such as the potential for forecast improvements and the degree to which variable energy resources will become more price-responsive. The ISO seeks stakeholder views on changes to the procurement of ancillary services due to renewable integration as well as to design considerations for the future, including the need for new products.

To prepare for increased procurement of regulation, the ISO is undertaking steps to enhance the variable regulation procurement tool to account for variable energy resources.[27] Hence, the regulation market over time could be expected to account for significant changes in procurement requirements from hour to hour. Production simulations are being conducted to validate that such an approach is feasible.

The combination of the increasing regulation capacity requirements and the higher regulation ramp rate requirements shown in Tables 1 and 2 also raise questions about whether new product definitions or pricing rules are needed in the regulation market. Specifically, there is some industry interest in a fast regulation product or in providing additional payments to resources that provide fast response. Some of these issues were raised in discussions about product and pricing rules to support non-generation resource participation in the ancillary service markets and the ISO is interested in the evolution of market participant views on this topic.

With respect to the increase in the load-following requirement, the ISO, along with other market and system operators, is examining changes to unit commitment algorithms to address ramp deficiencies in particular hours, and whether a load following or similar reserve product is likely to be required. The ISO is interested in stakeholder views on whether the load following requirements should be met by additional procurement of existing operating reserves designated as non-contingency or of a new type of reserve product.

Finally, the ISO seeks stakeholder views on forecasting significant variable energy resource ramping events and whether these events will warrant specific reserve requirements. The ISO is interested in stakeholder opinions on whether this potential need can be met through existing ancillary services at current procurement levels (i.e., creating a new category of contingencies for deployment of spinning reserves) or through additional procurement.

[27] Analysis of wind forecasting within the ISO indicates that forecast error is likely to be greatest when wind is operating in the mid-range of its production. This suggests that day-ahead forecasts of wind production can help calibrate regulation requirements needed to compensate for errors in predicting wind output. The diurnal production of wind and, even more significantly, solar resources provide ramp patterns that also can be accounted for by variable regulation procurement. The ISO currently does not recalculate the variable regulation requirements in its real-time market.

4.4 Allocation of Renewable Integration Costs

In the wholesale markets, the increased operational and market requirements associated with variable energy resources are likely to increase market costs for some services generally (e.g., regulation) and costs for all products in some high ramp hours, while a countervailing effect is that total spot energy costs are anticipated to be reduced as renewable production increases. Currently, the ISO does not assign any integration costs directly to variable energy resources and the PIRP reduces exposure to imbalance charges. This results in little incentive for variable energy resources to improve their capability to mitigate operational impacts.

Whether variable energy resources should be exposed to integration costs is currently a contentious issue being aired nationally through the FERC notice of inquiry. With regards to imports, the ISO noted in its dynamic transfers initiative that who bears the cost and responsibility for the incremental integration requirements is pertinent to both external resources seeking dynamic transfers and internal resources. In addressing the allocation of integration costs, the ISO has noted elsewhere that it must consider (1) what dynamically scheduled external resources would be charged by the ISO compared to the integration costs they would incur in external BAAs when scheduling firm energy into the ISO, and (2) the comparability of any proposed ISO charges to dynamically scheduled external resources and variable energy resources within the ISO.[28] As a provisional policy in the ISO's recent dynamic transfer initiative, the ISO concluded that it would not in that initiative consider new integration cost charges to dynamically scheduled external resources (that would create a discrepancy between treatment of external and internal resources). However, the ISO made it clear that this current initiative would consider such charges as applicable to both dynamically scheduled external resources and internal resources. Furthermore, once such a policy is adopted, it will apply to all resources without exception.

The ISO is thus interested in stakeholder views on the issue of cost allocation, and whether differences in how adjoining Balancing Authority Areas in the West calculate and assign integration charges will create distortions in the regional energy market.

To assist in consideration of the cost allocation issue, we note that as shown in Figure 3, ancillary services comprised between 1 and 2.4 percent of total energy costs between 2005 and 2009, with the current low costs a function of the low loads and the more efficient procurement of ancillary services under the new market design. Hence, while ancillary service costs and prices could be expected to increase with higher loadings of variable energy resources, as shown in Tables 1 and 2, these costs start from a low base. Furthermore, there will be substantial ancillary service capacity on the existing fleet for some time and the higher procurement requirements should draw in additional resources, such as storage and demand response. Other components of integration costs, such as changes to the real-time dispatch or load following requirements, are more difficult to estimate, but some indicative results will be forthcoming from the production simulation studies.

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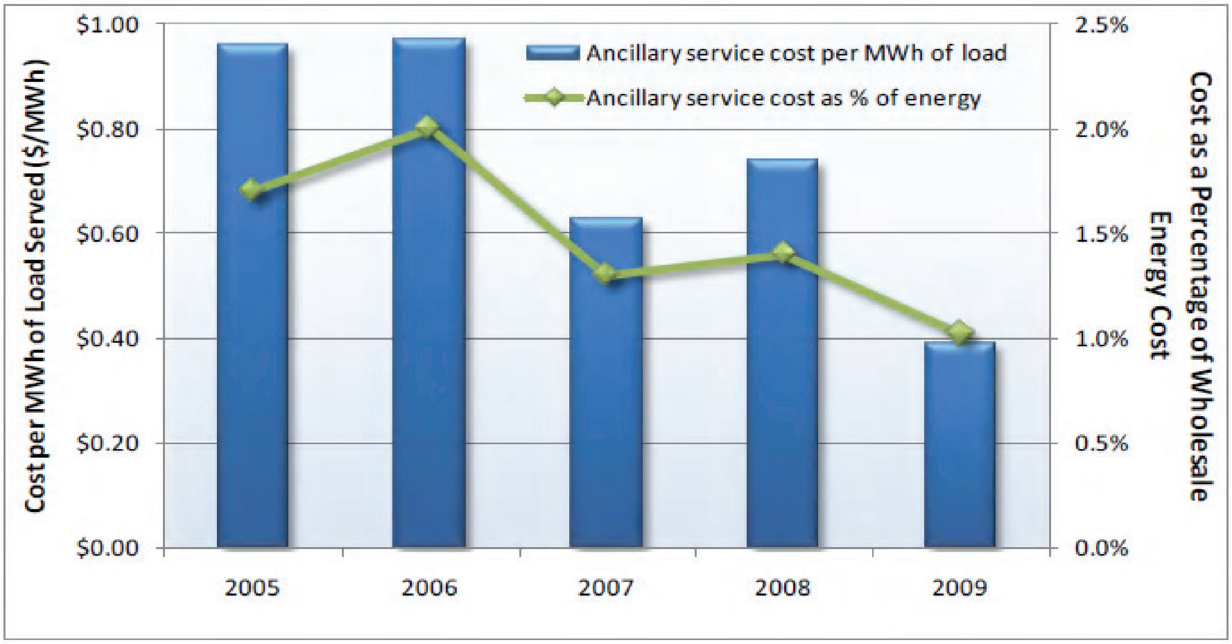
[28] See ISO, Dynamic Transfer Straw Proposal, March 10, 2010, pg. 6, available at http://www.caiso.com/2755/2755e7b852d20.pdf.

Figure 3: Ancillary Service Costs, 2005-2009



4.5 Impacts of Changes in Wholesale Market Revenues due to Renewable Resources

The forthcoming ISO operational and market simulations will provide insight into possible changes in spot market energy revenues as the increasing volume of renewable energy displaces conventional gas generation. As shown in other studies, when increases in renewable energy production outpace load growth, wholesale energy market prices and costs decrease and generators may have to increase their reliance on Resource Adequacy and other capacity payments.[29] The ISO is just beginning to evaluate the possible near-term and longer-term implications of such potential price trends for spot market design and its relationship to the prevailing Resource Adequacy program design in California. For example, the ISO has recently asked stakeholders to consider whether "backstop" capacity procurement by the ISO should target resources that provide specific operational characteristics as needed to support renewable integration.[30] The ISO is thus interested in stakeholder views on how changes in

[29] See, e.g., PJM, Potential Effects of Proposed Climate Change Policies on PJM's Energy Market, January 23, 2009, available at http://www.pjm.com/~/media/documents/reports/20090127-carbon-emissions-whitepaper.ashx. This study of PJM shows that increased renewable energy production reduces energy prices (while carbon pricing increases them). Similar studies have been conducted for several ISO/RTO regions.

[30] See ISO, Issue Paper, Updating Interim Capacity Procurement Mechanism, and Exceptional Dispatch Pricing and Bid Mitigation, June 9, 2010, available at http://www.caiso.com/27b0/27b0eb0cf3e0.pdf.

various market products and pricing, including Resource Adequacy, could affect revenues, market behavior, and investment in needed integration capabilities by conventional generation.

5 Stakeholder Process

The ISO plans to conduct several phases of this initiative over the next several years to address near term, midterm and long term operational needs. At the conclusion of each phase, the ISO will seek Board of Governor and FERC approval of any tariff changes needed to implement proposed modifications.

The ISO recognizes that the large scope and complexity of the issues to address renewable integration will require significant effort from market participants. In determining topics to address in each phase of this initiative, the ISO will seek to balance resource constraints, both internal and external, with the timeframe of when the design changes are needed to address operational needs. As additional findings become available from the 20 percent and 33 percent RPS renewable integration studies, they will further inform the process and influence the priority of market design enhancements to be included in future phases.

During the July 16, 2010 Stakeholder Forum, a panel of market participants will discuss their current views on how to mitigate or resolve the expected operational needs for renewable energy integration, including potential market enhancements. Based upon stakeholder feedback through the forum and written comments, the ISO will outline in an August 4, 2010 issue paper the proposed scope of topics to be addressed in the initial phase of this initiative. Also, the ISO will include topics referred from prior stakeholder initiatives in development of phase 1 topics.

5.1 Stakeholder Feedback – Summary of Key Issues

Although a discussion of the issues raised in this paper will occur at the ISO's July 16, 2010 stakeholder forum, the ISO encourages market participants to provide additional input through written comments subsequent to the forum. Specifically, the ISO seeks input on the following questions:

- Are market design rules needed to provide incentives or directives for variable energy resources to schedule in the day-ahead market? Or can other market entities (such as convergence bidders) take the position of variable energy resources sufficiently so that no such rules are needed?

- Given the increased levels of variable energy production, are changes to the PIRP rules for financial settlements of imbalance energy and for bidding in the ISO energy and ancillary service markets needed? How should the California ISO proceed with integrating variable energy resources into commitment and dispatch routines compared to other ISOs and RTOs?

- Are further market rule changes needed to provide incentives to variable energy resources to actively participate in the ISO markets? For example, is allocation of ancillary service costs to variable energy resources needed to provide incentives to mitigate their impact on integration requirements?

- What types of ancillary services, if any, are needed to support reliable integration of variable energy resources at least-cost? Should the ISO consider new types of ancillary services, such as reserves specifically procured to address extreme ramps or to provide load-following? When should the ISO implement any potential new products to address the anticipated increases in variable energy resource production (i.e., by the 20 percent RPS or between the 20 percent RPS and the 33 percent RPS)?

- Are current market products and pricing rules sufficient to compensate conventional generation for anticipated changes to commitment and dispatch to support renewable integration, most notably to cover any increased operations and maintenance costs? Are current products and prices, including resource adequacy contracts, sufficient to provide incentives for investment to improve operational capabilities?

- As the ISO seeks to integrate additional renewable energy from resources outside its Balancing Authority Area (e.g., through dynamic transfers), how should the ISO allocate integration costs (given that external Balancing Authority Areas are explicitly charging wind resources for integration services)?

- Considering the other areas in which the ISO is considering changes that could affect market operations and market design (e.g., Exceptional Dispatch), which areas of operational uncertainty and market needs should be addressed under the phases of this initiative and which should be addressed under separate initiatives?

- What additional market design issues, if any, should be addressed under this initiative?

- How should the ISO sequence the market design and operational issues that it addresses over the coming 1-2 years?

5.2 Timeline

Item	Date
Publish Issue Paper	July 8, 2010
Stakeholder Forum	July 16, 2010
Stakeholder Written Comments Due	July 30, 2010
Publish Phase 1 Scope and Issue Paper	August 11, 2010
Stakeholder Meeting	August 18, 2010
Stakeholder Comments	August 25, 2010
Publish Phase 1 Straw Proposal	September 7, 2010

Stakeholder Meeting	September 14, 2010
Stakeholder Comments	September 21, 2010
Publish Phase 1 Draft Final Proposal	October 7, 2010
Stakeholder Meeting	October 14, 2010
Stakeholder Comments	October 24, 2010
Board of Governors Meeting – Phase 1	December 14-15, 2010

6 Next Steps

The ISO will hold a stakeholder forum on July 16, 2010. The ISO seeks stakeholder written comments following the meeting by July 30, 2010. Please email all correspondence to RI-MPR@caiso.com.

<u>**CERTIFICATE OF SERVICE**</u>

I hereby certify that I have this day served a copy of ***Reply Comments of the California Energy Storage Alliance on Resource Planning Assumptions - Part 2 (Long Term Renewable Resource Planning Assumptions) – Track 1*** on all parties of record in proceeding ***R.10-05-006*** by serving an electronic copy on their email addresses of record and by mailing a properly addressed copy by first-class mail with postage prepaid to each party for whom an email address is not available.

Executed on July 16, 2010, at Woodland Hills, California.

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CERTIFICATE OF SERVICE – R.10-05-006

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