California ISO
Shaping a Renewed Future

Renewables Integration Market Vision & Roadmap

Day-of Market

Initial Straw Proposal • 7/6/2011

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1 Introduction

For decades the power industry has operated under a structure of relatively stable technologies and operational practices, and has needed to evolve only to accommodate gradual growth in demand and incremental changes to the supply fleet. With new policy mandates for a cleaner, greener supply fleet, however, significant changes are required in virtually all aspects of industry activity. For several years now the ISO has been proactively assessing the impacts of environmental policy mandates and new technologies and has worked with stakeholders to develop practical approaches to support state policy goals and facilitate the participation of new resource types. The ISO's integration studies have provided important insights into the operational requirements to maintain reliability with high levels of participation by wind and solar resources, and recent market product enhancements have provided the means for new technology types to participate in the ISO's spot markets. Yet more work remains to be done. Although the ISO's comprehensive new market structure implemented in 2009 was designed for flexibility to adapt to such changes, it was largely designed before the ISO or market participants began to grapple with the impacts of large-scale changes to the supply fleet driven by the new environmental policies and emerging technologies. It is therefore necessary and timely to review the current ISO market structure comprehensively, informed by the integration studies and the recent design changes, and determine what further market enhancements are needed to both adapt to and facilitate the coming changes while maintaining the ISO's traditional core functions of providing reliable open-access transmission service and running efficient spot markets.

Against this backdrop the ISO now provides its initial straw proposal as the next major step towards a comprehensive Renewables Integration Market Vision and Roadmap. Following an extensive stakeholder process described at the end of this document, ISO management intends to present the Vision and Roadmap to the Board of Governors for discussion at its December 2011 meeting. Then in early 2012 the ISO will initiate stakeholder activities to develop detailed proposals for market products and other enhancements to be incorporated into the ISO market structure after receiving Board and FERC approval.

This paper provides context, background and guiding principles for this phase of the ISO integration of renewable resources initiative, and offers an initial straw proposal, including some options, for enhancements to the ISO's day-of (i.e., post-day-ahead) markets.[1] Specifically, this paper discusses:

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[1] With this paper the ISO introduces the term "day-of markets" to encompass all market processes and activities that are performed during the operating day, subsequent to the establishment of day-ahead schedules and

- What the ISO is trying to accomplish in this initiative and by when;
- The principles proposed for assessing the merits of alternative market enhancements;
- A review of the operational challenges associated with high levels of participation by variable energy resources such as wind and solar;
- A day-of market framework, including two alternative approaches for modifying the real-time dispatch, that should enable the ISO to maintain reliability and robust market participation in an environment where there is greater resource diversity and production variability; and
- A proposed schedule of stakeholder activities leading to presentation of the Renewables Integration Market Vision and Roadmap to the ISO Board in December, 2011.

The decision to focus this paper on the day-of markets follows the same logic that the ISO followed in adopting locational marginal pricing: in order to maintain reliable grid operation and stable efficient markets, the key market results – unit commitment, schedules, dispatches, and prices – must align with real-time operating needs, grid conditions, and the laws of physics. Thus the proper starting point for this effort must be the real-time market and the post-day-ahead processes that support real-time. Subsequent activities in this initiative will consider markets and market processes that are conducted in the day-ahead and more forward time frames, as outlined in the last section of this paper. As the conceptual design becomes more final, the ISO will also look to prioritize and develop a phased implementation roadmap and will seek to give particular priority to accelerating the implementation of new market products that will provide enhanced revenues to resources that can provide critically needed renewable integration services (e.g., real-time imbalance services).

2 Statement of Purpose

The purpose of the Renewables Integration Market Vision and Roadmap initiative is to take a holistic view of the existing ISO markets to identify and propose enhancements that address and help facilitate the transformative changes resulting from the state's energy and environmental policies and the emergence of new technologies, in a manner that maintains safe and reliable operation of the grid and stability of the spot markets. The ISO goal is to evolve the existing market structure to:

- Enable ISO operators to efficiently and reliably operate the grid with a more diverse and variable supply portfolio;

awards in the integrated forward market (IFM) and residual unit commitment (RUC) processes of the day-ahead market. Today the day-of markets include the real-time dispatch (RTD), the real-time unit commitment (RTUC) or real-time pre-dispatch (RTPD), which includes the hour-ahead scheduling procedure (HASP), and the short-term unit commitment (STUC).

- Be flexible to accommodate future changes to energy policy goals and new resource types without requiring further substantial market changes; and
- Resolve known market and performance issues and minimize the need for manual interventions.

Now that California has a 20% and 33% renewable portfolio standard (RPS), as well as Assembly Bill 32 which calls for reductions in greenhouse gas emissions, the ISO needs stakeholder input to help determine the most effective market enhancements to meet these objectives. The ISO seeks comments on what specific changes are necessary to efficiently and reliably operate the grid in an environment where a large number of renewable, variable energy resources are interconnected to the transmission and distribution systems.[2] The significant operational challenge for the ISO is to reliably maintain continuous system balance given the variability of the energy output of variable energy resources, which is caused in large part by the intermittent nature of their fuel source, e.g., solar irradiance and wind energy. Increased variability in the output of the supply portfolio will result in less predictability and, therefore, greater operational uncertainty. The ISO must anticipate and manage this variability to balance supply and demand as well as to meet applicable reliability criteria.

Meanwhile, technological improvements and innovations and state policy targets may enable potentially thousands of MW of distributed energy resources to interconnect to the grid at the sub-transmission and distribution level, creating new and unique challenges for system operators to forecast, monitor and reliably operate the grid. The ISO is currently assessing its operational needs under this changed environment, for example, to assess alternative approaches for providing adequate visibility to the real-time performance of these resources. From the perspective of this Vision and Roadmap initiative, the ISO must make sure that the market enhancements being developed here will also accommodate and facilitate the expansion of distributed energy resources as a major contributor to achieving a 33% or greater RPS.

The market vision the ISO develops in collaboration with stakeholders over the next few months will be a conceptual, yet detailed description of important market enhancements that the ISO plans to implement in the 2014 time frame. In support of and as a companion to the market vision, the ISO will develop a roadmap to lay out the implementation of near term, high priority changes to the existing markets as well as longer-term market enhancements — potentially including new spot market products and forward capacity products — that will provide the operational characteristics needed from the resource fleet to reliably and cost-effectively integrate

[2] "Variable energy resources" is the term used by the Federal Energy Regulatory Commission to describe renewable resources that have variable or intermittent production. Variable energy resources is 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.

renewable, variable energy resources and distributed energy resources. The roadmap will highlight specific activities and milestones and a timeline for delivering prioritized market design enhancements, but will not contain implementation details for specific market products or other enhancements. Those details will be developed in the next phase of the renewables integration initiative beginning early in 2012, where specific market enhancements and the associated tariff language will be developed in collaboration with stakeholders.

3 Background

California is leading the way to a new greener grid. Approved by the California legislature, SBX1-2 increases the state renewables portfolio standard to 33% by 2020. The ISO, its stakeholders and the state energy and environmental agencies must now determine best approaches to meet public policy goals. Rules, regulations and policies, along with the ISO wholesale electricity market, must align to support the clean energy future envisioned by SBX1-2.[3]

To this end, the ISO is considering refinements to its wholesale electricity market that effectively integrate the operational characteristics of variable energy resources and accommodate the development of many small distributed energy resources. With a clear legislated mandate, the ISO believes it is prudent to make a thorough and timely assessment of the market and operational refinements required to reliably operate the grid under a 33% RPS. This must be done even as more specific information on the quantity of renewable resource energy production and the mix and location of renewable resource types develops.

The ISO and its stakeholders have learned a lot over the past few years about future market and operational needs. First, renewable resources will be displacing energy production from in-state gas fired resources. The amount of capacity and energy required from gas-fired resources is a function of the amount of balancing energy and capacity reserves the ISO will need to support a high level of energy production from variable energy resources. The ISO 20% RPS study showed that the displacement from wind and solar resources causes the net load – load minus wind and solar production – to affect energy production from gas-fired units across the day. With a 33% RPS, on some days up to 50% or more of energy production during the peak hours may come from variable energy resources, such as solar (assuming a high in-state development of solar resources). Hence, solar production could substantially displace energy production from gas-fired peaking units.

[3] SBX1-2 requires California's electric utilities to reach the 33% RPS in three compliance periods. By December 31, 2013, utilities must procure renewable energy products equal to 20% of retail sales. By December 31, 2016, utilities must procure renewable energy products equal to 25% of retail sales, and by December 31, 2020, utilities must procure renewable energy products equal to 33% of retail sales and maintain that percentage in following years.

Second, with a large number of renewable resources displacing energy production from gas-fired resources, the gas-fired fleet will experience increased cycling and will operate more often at minimum operating levels. For instance, the production simulations conducted for the 20% RPS study suggested that combined cycle plants would see a 35% increase in the number of starts compared to the benchmark scenario for 2012. However, the study also shows that conventional gas-fired steam units and simple cycle gas turbines are expected to operate less often and have fewer starts. As we transition from the 20% to the 33% RPS, the ISO will likely need to procure additional reserves and balancing energy. As this shift occurs, the fleet of conventional gas-fired steam units may be needed more often to provide balancing energy, incurring an increased number of start-stop cycles.

Third, wholesale energy prices will be affected because of the changing supply portfolio. Significant numbers of renewable resources integrated into the grid will lead to a reduction in energy market prices in certain hours relative to today. For instance, off-peak energy prices are expected to be lower because of higher wind energy production. Nevertheless, how wind and solar production will affect on-peak prices will depend on the production efficiency and, therefore, cost of gas-fired units that have historically operated during peak hours. In addition, real-time prices may become more volatile, reflecting the energy supply nature of variable energy resources.

Key findings of the 20% RPS study indicated that to successfully integrate renewable resources the ISO will need increased operational flexibility. This will require additional ramping capability, and balancing energy and ancillary services from both generation and non-generation resources. There will also be a need to more frequently mitigate frequency excursions and over-generation conditions.

The ISO expects the results of its 33% RPS study to provide more insights around the quantities of balancing energy, ancillary services, and ramping capability needed to support the integration of many variable energy resources. In the meantime, the 20% RPS study provides a firm foundation for discussing market enhancements needed to satisfy California’s future operational and reliability needs under a 33% RPS.

4 Guiding Principles

The six guiding principles below function as criteria for assessing the comparative merits of alternative market enhancements, new products and services, and related market rules. The principles will enable the ISO to efficiently operate the grid under a 33% or greater renewables portfolio standard while building system flexibility that will help accommodate the technological advances that will emerge over the next decade.

The six guiding principles for this initiative and their expected outcomes are as follows:

Technology Agnostic

Principle	The ISO market accommodates new resource types based on their performance capabilities, without preference for specific technologies.
Expected Outcomes	✓ Enables any technically capable resource, regardless of technology, to provide services on a level playing field based on performance ✓ Resource technologies are viable based on innovation and competition rather than on resource-specific market rules ✓ Integrates devices that can both produce and consume energy

Transparent

Principle	The ISO market relies on price signals to incent participant behaviors that align with ISO operating needs.
Expected Outcomes	✓ Products are competitively procured through transparent market mechanisms ✓ Procurement targets are transparent and tied to operational needs ✓ Operating constraints are reflected in price signals, minimizing non-market solutions ✓ Prices incent performance from supply and demand that supports operational needs and encourages mitigation of generation variability and congestion ✓ Pricing rules allow transparent allocation of renewables integration costs

Deep and Liquid

Principle	The ISO market attracts robust resource participation.
Expected Outcomes	✓ More economic bids and less self-scheduling ✓ More price responsive demand ✓ Increased participation from resources in other balancing authorities through improved interchange scheduling ✓ Minimal seams issues with neighboring balancing authorities

Durable and Sustainable

Principle	The ISO market ensures an efficient mix of resources to maintain reliability and attracts new investment when and where needed.
Expected Outcomes	✓ Resources are commercially viable through a combination of ISO market revenues and forward contracts ✓ Resource fleet and mix enables the ISO to meet NERC and WECC reliability standards ✓ Resources are incented to enhance availability and performance ✓ Market products and rules are stable ✓ Known real-time market issues are addressed

Flexible and Scalable

Principle	The ISO market easily adapts to new and changing energy policy goals and resource mix.
Expected Outcomes	✓ Establish flexible market design that can accommodate reasonable changes in policies and technologies ✓ Recognize key linkages and coordinate with initiatives and proceedings of state agencies ✓ Compatible with high penetration levels of distributed energy resources

Cost-effective and Implementable

Principle	The ISO market design leverages existing ISO infrastructure, industry experiences and lessons learned.
Expected Outcomes	✓ A market design that is cost-effective to implement for market participants and the ISO ✓ Build on existing functionality and market systems to extent possible ✓ Design leverages the experience of other ISOs/RTOs as to what works and what does not; do not re-invent

5 Operational Challenges

The ISO is keenly interested in identifying and resolving the lower probability operating conditions under a 33% RPS that will make it difficult for the ISO to balance supply and demand in real time. With the introduction of large numbers of variable energy resources, the ISO is particularly concerned about large, fast ramps that are difficult to forecast. Thus, a key purpose of this initiative is to translate real-time operational challenges into market changes that ensure the system continues to safely and reliably satisfy demand even under extreme operating conditions.

The majority of new renewable generation capacity needed to satisfy the state's 33% RPS will predominately come from additional variable energy resources such as wind and solar. The key operational characteristic of such resources is the variability of their generation over different time-frames (seconds, minutes, hours) and the uncertainty associated with forecasting their production (i.e., forecast error). As such, the integration of variable energy resources will require increased operational flexibility—notably the capability to provide load following and regulation in wider operating ranges and at ramp rates that are faster than what is generally provided today. Forecast uncertainty associated with wind and solar production increases the need for the reservation of resource capacity to ensure that operational requirements are met in real time. There is also the concern of increased over-generation, a condition where there is more supply from non-dispatchable resources than there is demand. Flexibility will be needed from dispatchable resources to respond to these operational needs. The existing and planned generation fleet will likely need to operate for more hours at lower minimum operating levels and provide more frequent starts, stops and cycling over the operating day. Additionally, certain conventional generators will operate at lower capacity factors because of the increased production from renewable energy resources.

Below is a summary of the key operational challenges the ISO must address, preferably through market solutions, where possible:

5.1 Net Load-following

A core ISO operational and market function is forecasting system load and renewable production in the day ahead and real time. This includes ensuring that sufficient supply resources are committed so that deviations from hourly schedules can be accommodated by those resources under ISO dispatch control. Historically, intra-hour deviations were caused by changes in load, hence the term "load-following". With increased variable energy resource production, the net load-following requirement—i.e., the amount of net load following capacity needed because of load schedule deviations plus variable energy resource deviations—could increase substantially in certain hours because of forecast uncertainty related to wind and solar fuel supply variability.

5.2 Self-scheduling

The empirical analysis from the ISO 20% RPS study demonstrated a shortage of 5-minute net load-following capability in the downward direction when resources are self-scheduled, as compared to offering their actual physical capabilities for economic dispatch. These results were further substantiated by using a production simulation. Hence, the 20% RPS study made clear that the ISO must pursue incentives or mechanisms to reduce the level of self-scheduled resources or increase the operating flexibility of otherwise dispatchable resources.

5.3 Ramping

The ISO must rely on ramping capability to balance the less predictable energy production patterns of variable energy resources, such as that from wind and solar resources.[4] Under-forecasting errors in production require dispatching flexible resources to higher levels and the reverse for over-forecasting errors. The ISO must accurately follow load and minimize inadvertent energy flows. This calls for having ramping capacity in both speed and quantity, which is dictated by how fast and how much variable energy resources' production patterns change. To meet this operational challenge, the ISO needs enough flexible resources committed with sufficient ramping capability to balance the system within the operating hour. This includes having enough ancillary services, specifically regulation energy, available to address any second-to-second real-time imbalances between generation and demand.

5.4 Over-generation

Over-generation occurs when there is more generation and imports within a balancing area than load and exports can use. This situation develops after the system operator has exhausted all decremental energy bids available in the imbalance energy market, has pushed all regulating resources to the bottom of their operating range, and has exercised arrangements for out of market purchases for excess energy with neighboring balancing authorities.

When anticipating over-generation conditions, ISO operators will send out a market notice to request additional decremental bids. If insufficient decremental bids are received from scheduling coordinators and the area control error can no longer be maintained within acceptable limits, ISO operators could declare a system emergency. The fundamental causes that precipitate an over-generation condition are:

- A mismatch between scheduled generation and forecasted load;
- Managing must take generation during low load conditions;[5]
- Load and resource forecast errors;
- More imports are scheduled than there is load on the system;
- Excess must take hydro generation and the need to avoid spilling water; and
- Excess unscheduled wind and solar generation.

[4] Those variable energy resources that do not have the ability to firm and shape their production output
[5] Regulatory must-take generation is defined in ISO Tariff Appendix A- Master Definition Supplement.

5.5 Fleet Operations

The increased supply variability associated with the 33% RPS will cause more frequent dispatches and starting and stopping of flexible, gas-fired generators and, therefore, potentially more wear and tear. Lower capacity factors for dispatchable generation combined with potential reduced energy prices under a 33% RPS may result in decreased energy market revenues for the gas-fired fleet in all hours and seasons raising revenue adequacy concerns and the ability to support gas-fired generation resources that are necessary for dispatch flexibility and reliability.

5.6 Inertia and Frequency Response

The ISO is concerned that as variable energy resources displace conventional generation, the system may not have sufficient inertia to maintain system frequency or enough governor response to stabilize system frequency following a grid disturbance. Frequency excursions because of over-generation are possible during periods of high variable energy resource production and low system demand, such as during off-peak hours, weekends and holidays. Specifically, higher than scheduled or expected variable generation production levels can result in over generation conditions and ultimately over-frequency if dispatchable resources are already at their minimum load levels and regulation down capacity has been exhausted. Thus, the ISO believes it is essential for variable energy resources to have the ability to automatically reduce energy output in response to high frequency. This will become an increasingly important attribute as the percentage of variable energy resources in the supply portfolio increases over time.

5.7 Active Power Control

Variable energy resources must have the ability to limit active power output. The ISO's concern is if a line trips that forces a large solar photovoltaic resource off-line, when the line comes back in service, the ISO must have the ability to control the resource's ramp back on the system, i.e. the ISO would not want such a resource to instantaneously ramp its full energy output onto the grid the second the line comes back into service. Thus, ISO operators need the ability to instruct variable energy resources to limit power production, or disconnect from the system, for reasons that include the following:

- Risk of overloads because of congestion;
- Risk of islanding;
- Risk to steady state or dynamic network stability;
- Frequency excursions;
- Routine or forced maintenance; and
- Reconnecting to the system post-contingency

The ISO will further consider what active power control should be required to minimize this reliability impact.

5.8 Loss of Distributed Energy Resources

FERC Order No. 661 A states that a wind resource should not disconnect from the system in the event voltage drops to zero and remains there for as long as 150 milliseconds at the point of interconnection. NERC draft standard PRC-024 extends this requirement to all generators.

Likewise, it is desirable for distributed energy resources to remain connected to the system during fault conditions for a same duration, i.e., 150 milliseconds to maintain power system dynamic stability.[6] It may be possible to mitigate the impact of nuisance tripping during under-voltage and under-frequency events by expanding a resource's ride-through requirements. One issue created by expanding the ride-through capability is that distributed energy resources must avoid unintentional islanding that can occur when a circuit-level breaker opens.

6 Day-of Market Design Framework

6.1 Design Framework

This section of the paper presents the ISO's initial thinking on enhancing the day-of market to accommodate and manage the reliability impacts of increased variable energy resources and other emerging technologies on the grid and for resolving existing market-design challenges. The ISO recognizes that certain design choices may be constrained by external or regulatory developments (or non-developments) as well as implementation costs and complexities for the ISO and market participants. However, for this stage, the ISO describes two possible options for enhancing the day-of market structure that balance ISO objectives against the stated design principles and prudently takes into consideration market and seams issues in the Western Electricity Coordinating Council.

To develop these proposed market enhancements, the ISO has taken a comprehensive top-down market evaluation as a preferred approach versus working bottom-up from a list of needed enhancements. This approach should not be interpreted by stakeholders as a reworking of security constrained unit commitment, economic dispatch and locational margin pricing as basic ISO market structures; these elements of the market are fundamental to aligning market signals with operating needs, grid conditions and the laws of physics. The ISO is proposing enhancements to its

[6] This requirement does conflict with IEEE 1547 standard which requires that inverter-based generation trip off-line for low voltage faults near the generator inverter terminals.

products, market timeframes, and incentives, within the context of constrained optimization and locational marginal pricing.

To provide a logical approach to deliver a market vision and roadmap by year end, the ISO is beginning with proposed enhancements to the day-of markets, starting with real-time where market outcomes must align with grid topology and operating conditions and must support grid reliability. It is in the real-time market where the grid is actually managed. Other markets, such as day-ahead and forward markets, are designed to ensure that needed energy and capacity is planned and committed for real-time operation. These markets will be considered for potential enhancement starting in the next round of this initiative, once there is a solid understanding of what is needed in the day-of market, proposals for the day-ahead and forward markets can be developed.

The day-of market framework options presented here are straw proposals. After assessing the needs of the future day-of market structure, the ISO is proposing two options for enhancing the existing market. The ISO is open to other market design frameworks; however any proposal should address the operational challenges outlined in section 5 and adheres to the guiding principles in section 4 of this paper.

The two options contain many similar features. The major difference is the timing of the pricing of energy:

- Option A
    - The Real Time Economic Dispatch (RTED) occurs every 15 minutes
    - Prices would be set every 15 minutes
    - Energy, Ancillary Services, and Short Term Unit Commitment would all be co-optimized every 15 minutes
- Option B,
    - RTED remains at 5 minutes
    - Prices would be set every 5 minutes
    - Energy and Ancillary Services are co-optimized in the 5 minute RTED
    - Some form of Short Term Unit Commitment process would continue to run every 15 minutes

Both options contain the following enhancements to today's market structure:

- Retain the current two-settlement market system.
- Introduce a new ancillary service product called Real Time Imbalance Service (RTIS) which has a more granular dispatch than today's 5-minute RTED, but less granular than regulation.
- Eliminate the existing Hour Ahead Scheduling Process (HASP) for clearing and pricing intertie bids.

- Provide for hourly scheduling on the interties more simply than the current HASP, eliminating unintended consequences that arise with virtual bidding and other price disparity concerns.

There are several open questions as to whether there are other new market processes or products that might be useful, including:

- Inertia and/or frequency control.
- On-demand Residual Unit Commitment.

The remainder of this section describes the ISO proposals in greater detail and discusses the pros and cons of the various elements of the proposals. The discussion addresses the operational challenges and guiding principles that have been previously discussed.

6.2 Day-of Market Proposals

AS discussed above, the ISO is putting forth two options for how to revise the day-of market structure. Since the two options share many of the proposed enhancements, we will begin by describing those enhancements that are common to both options.

Retain two-settlement design- Day-ahead and Real-time Markets

The ISO considered the merits of a full hour-ahead market but believes that the complications of adding a third settlement would create significant issues without providing any clear benefits. A third settlement would have to be incorporated into all settlement processes and systems, and the implications of adding hour-ahead convergence bidding would need further investigation. It is not obvious if convergence bidding would be needed between day-ahead and real-time only, or if pricing would need convergence between day-ahead and hour-ahead and between hour-ahead and real-time. The benefits of a full hour-ahead market would be hourly scheduling and settlement of inter-ties without the issues created today because of price disparities between internal and inter-tie nodes. The ISO believes that this issue can be more effectively dealt with by simpler methods that don't create the complexities of a three settlement system.

No Hour-ahead Scheduling Process (HASP) in the real-time market

The ISO believes elimination of the HASP is feasible with more granular scheduling at the interties. In a recent NOPR, FERC raised the questions of whether 15-minute scheduling should become the standard used by balancing authorities. The ISO believes that given the increasing level of renewable energy across the country, as well as experiments already in consideration that would test the ability to schedule on the interties at less than one hour increments are indications that in the future scheduling will likely be at some period less than an hour.

Further, if there is a need to retain some form of hourly-scheduling of imports and exports, the ISO believes that this can be accomplished in a simpler fashion than having a HASP. The ISO proposes to design the simplest possible approach working with other balancing authorities to accommodate hourly schedules until they are able to move to more granular scheduling. In the interim, this could be accommodated through self-scheduling, or by submitting a bid for the first period of each hour and putting in price taking bids for the remaining intervals of the hour. Alternatively, the ISO could consider the bid using the forward looking feature of RTED to estimate how the bid would function over all intervals of the hour; however there would be no guarantee of bid cost recovery.

The ISO has experienced a number of market issues related to price disparities between inter-ties committed based on the HASP price and internal generation committed based on the 5-minute interval price. Removing these known market issues is an important objective for this initiative. Using the RTED prices for all nodes, internal and external, will remove any price disparity between internal prices and the inter-tie prices.

6.2.1 *Real-time Market*

After carefully examining current and anticipated issues, the ISO has formulated two possible options for enhancing today's real-time markets to better function under expected future conditions. Both options are variants of a similar market vision that incorporates as an enhancement to today's markets a new ancillary service, called Real Time Imbalance Service (RTIS). RTIS will enable the ISO to balance the grid between price setting RTED runs, but less frequently than regulation. Both options would co-optimize energy and Ancillary Service markets in the real time economic dispatch and would extend how far forward the market software considers in performing the RTED.

The two options differ in how often the ISO performs Real Time Economic Dispatch (RTED) and establishes the real time prices used to settle the market. Option A would change the RTED and pricing interval from today's 5 minutes to 15 minutes. This 15 minute RTED run would eliminate the need for today's Real Time Preliminary Dispatch (RTPD), and would also allow the co-optimization of not just energy and ancillary services, but also the unit commitment process. The second option, Option B would keep the dispatch and pricing interval the same as it is today, 5 minutes. This option would also retain some form of the Real Time Preliminary Dispatch (RTPD) as the Short Term Unit Commitment (STUC).

The remainder of this section is split into Section 6.2.1.A which describes the real time market for Option A and Section 6.2.1.B which explains how Option B would differ in the functioning of the real time market. This structure is mirrored in Section 6.2.2 discussing the Ancillary Service Markets and Section 6.2.3 which discusses the unit commitment process. Finally, Section 6.2.4 discusses potential new products that are being considered in either of the options.

6.2.1.A Real Time Market under Option A

Real-Time Market Structure

- The Real-time market for energy and ancillary services will clear and settle every 15-minutes.
    - Real time prices will be established every 15 minutes in this process.
    - Binding schedules will be established every 15 minutes.
- The market will co-optimize real-time energy, ancillary services (see below for proposed changes to ancillary services market) and unit commitment decisions.
- The market will look forward up to 8-10 hours in each run to ensure that sufficient generation is available through the unit commitment process.
- Market participants may submit bids each hour for the following hour up to half an hour before the hour (this may initially have to be 45-minutes to accommodate existing tagging timelines, but the ISO will work to shorten this time to 30 minutes or less).
- Scheduling coordinators for variable energy resources could submit revised schedules every 15-minutes to allow for accurate scheduling (economic bids would be submitted hourly).
- Dispatch instructions (i.e., 15-minute schedules) will be issued to all units between 12.5 and 15-minutes before the start of the operating interval.
- The ISO is considering having a 10 minute ramp period, from 5-minutes before to 5-minutes into the subject 15-minute interval and specifically seeks stakeholder comments on this aspect of the proposal.

Real-time bids

- Bid components:
    - Energy price
    - Minimum load
    - Start-up costs
    - Ramp rate (or schedule of ramp rates) in MW/10 minutes (in both directions)
        - Ramp rate will be used to ensure feasible dispatch – i.e. units will not be moved more in each 15-minute interval than they can ramp in the 10 minute ramp period
    - If certified for regulation, contingency reserves and/or Real-Time Imbalance Service, there may be additional bid elements included for providing these services (see below under the description of ancillary services).

Additional Real-Time Market Modifications

The RTED that occurs every 15-minutes will also serve as the unit commitment process. As with today's Real-time Pre-dispatch (RTPD), this 15-minute scheduling will look ahead, but be expanded to 8-10 hours from 270 minutes today to ensure the feasibility of achieving system balance without violating ramping restrictions or other constraints.

- It will recognize the abilities of the various units to ramp during the 10 minute ramping period in each 15-minute interval.
- It will commit sufficient resources to AS (regulation, Real-Time Imbalance Service, spin and non-spin reserves) to meet all reliability and ramping needs expected during the 15-minute interval.

6.2.1.B Real Time Market under Option B

Under the ISO's Option B, the main difference from Option A is that the RTED will continue to occur every 5 minutes as it does today, rather than shift to every 15 minutes.

Real-Time Market Structure

- The Real-time market for energy and ancillary services will clear and settle every 5 minutes.
  - Real time prices will be established every 5 minutes in this process.
  - Binding schedules will be established every 5 minutes.
- This market will co-optimize real-time energy and ancillary services.
- One difference from Option A is that Option B would retain some form of today's Real Time Preliminary Dispatch.
  - This market will look forward up to 8-10 hours in each run to ensure that sufficient generation is available through the unit commitment process.
- Market participants may submit bids each hour for the following hour up to half an hour before the hour (this may initially have to be 45-minutes to accommodate existing tagging timelines, but the ISO will work to shorten this time to 30 minutes or less).
- An open question with the 5 minute RTED is whether scheduling coordinators for variable energy resources could submit revised schedules every 5 minutes, every 15 minutes, hourly, or some other period. (economic bids would remain hourly)
- Dispatch instructions will continue to be issued at 2.5 minutes before the period.

Real-time bids

Real time bids would be the same as under Option A.

Additional Real-Time Market Modifications

Unlike Option A, unit commitment under Option B would not be co-optimized with the energy and Ancillary Services markets, but would continue to occur as a Short Term Unit Commitment (STUC) process every 15 minutes in the Real Time Preliminary Dispatch. Similar to Option A, the look ahead during this STUC will be expanded to 8-10 hours.

- This STUC will recognize the abilities of the generator to provide ramping.
- This STUC will commit sufficient resources to meet all reliability and ramping needs.
  - This may involve the use of some form of flexi-ramping constraints.

6.2.2 *Ancillary Services markets:*

As explained above, both Option A and Option B incorporate the creation of new ancillary service, Real Time Imbalance Service, and co-optimize the procurement of energy and ancillary services in the Real Time Economic Dispatch.

6.2.2.A Ancillary Service Markets under Option A

- Procurement of all Ancillary Service products will be co-optimized with energy and unit commitment during the 15-minute RTED.
- This will be a full re-optimization of the ancillary service markets, not just procurement of additional capacity when needed, which is the case today.
- The substitutability of the various ancillary service types will need to be examined carefully under this proposed structure.
- Regulation service may no longer be substitutable for reserves since regulation will only be required to sustain energy output for few minutes and not an hour, or even half an hour.

Operating reserves

- Capacity designated by scheduling coordinators as “non-contingency” reserves in the Day-ahead procurement and which are not needed for contingency reserves for the following interval will be included in the real time energy market.
- Procurement of real time reserves from a unit at any point during the day will not change the” non-contingency” designation for the day-ahead reserves amount not needed for contingency reserves in any interval

- Reserves will continue to be a 10-minute product, although they will be procured in 15-minute intervals. Ancillary service certified units must still be able to provide reserves within 10-minutes.

Regulation

- Under the proposed market structure, regulation would be bi-directional, with those selected units providing both regulation up and down. Since the Real Time Imbalance Service would be dispatched every minute, regulation would be a true "grid balancing" service, which would only provide regulation for a very short period and the ISO would return units to their null point every minute. This appears to support regulation as a bi-directional product.
- Procured amounts of regulation will be based on MW/min, and regulation units will only need to provide energy for 2 minutes until the next dispatch of the Real Time Imbalance Service.
- Provides an advantage to fast ramping units to provide regulation.
- Slower ramping units will more likely provide the proposed Real-time Imbalance Service.
- The amount of regulation capacity procured must be sufficient to balance the system until the 1-minute dispatch of Real Time Imbalance Service units can reset regulation units to their null point (i.e. 2 minutes).
- Payment will be in the form of a:
  - Capacity payment (can include opportunity cost of energy)
  - Mileage payment
  - Accuracy adjustment
  - If regulation is bi-directional, no net energy payment will be included.
    - Units will regulate in both directions.
    - The ISO will use Real-time Balancing Service to reset regulation units to their null point every one minute so net energy should be near zero.
    - Any anticipated costs should be rolled into the capacity bid.

Real Time Imbalance Service

The proposed day-of market design framework adds a new ancillary service called Real Time Imbalance Service (RTIS). This new product is designed to have dispatch instructions every one-minute to balance the system between the full Real Time Economic Dispatch, which runs every 15-minutes, and to drive regulation units back to their "null point" every minute.

- Procurement will explicitly consider ramping capability, thus providing a market-based product in lieu of the flexi-ramp constraint under consideration today.
- Similar to regulation, but dispatched every minute rather than every 4 seconds.
- Procurement will be based on MW and ramping capabilities.
- The amount procured will be sufficient to balance the system until the next 15-minute Real Time Energy Scheduling run is implemented (i.e. 30 minutes).
- Will be co-optimized with energy and other ancillary services. Units will likely have an energy schedule (at P-min or some "optimal" level) and then some amount in the Real Time Grid Support.
- Procurement may not be symmetrical up and down, and will vary over each day as needed
- Payment will consist of:
    - Capacity payment
    - Mileage payment
    - Net energy payment – at the 15-minute price (the ISO is considering a floor of $0 for upward movements)
    - Accuracy adjustment
        - This may be combined with or in addition to the variability costs assessed as discussed below for accuracy in following the 15-minute RTED dispatch instruction.
        - Continued inaccuracy above some level would disqualify units from providing RTIS in the future.

Bidding and dispatch of RTIS

- The ISO is considering how the bidding, selection and dispatch of units providing RTIS would occur. The desire is to develop a system that minimizes costs while providing opportunities for the resources to select the best options for their participation. The ISO anticipates that some resources will prefer to be used for balancing often and receive the mileage compensation for the net energy provided, while other units will prefer to receive the capacity payment for standing by to provide grid support, but they would rather not have their unit moved unless needed. The ISO is considering two methods to accomplish this. Both would have the resource provide a capacity bid for providing RTIS service, but would differ on how dispatch would be done:
    - One possibility would be for units to put a flag in their bid to indicate their willingness to have their resource moved, similar to the flag they currently use to indicate their desire to provide contingency only or non-contingency reserves.
    - A second possibility would be for the resources to submit a mileage bid which would then be used to dispatch the units.

        - Under this option, a decision needs to be made as to whether this bid would be used only for dispatch, with mileage paid at some administratively determined rate, or if mileage would be paid at an as bid rate, or whether there would be a market clearing mileage rate paid to all units.

6.2.2.B Ancillary Service Markets under Option B

- Procurement of all Ancillary Service products will be co-optimized with energy during the 5-minute RTED.
- This will be a full re-optimization of the ancillary service markets, not just procurement of additional capacity when needed, which is the case today.
- Procurement of Ancillary Services may be constrained by STUC which occurs every 15 minutes in RTPD.

- Reserves and Regulation would be the same as under Option A.
    - Reserves would continue to be a 10 minute product, although they would be scheduled every 5 minutes.
        - A question arises as to what would happen if a resource is scheduled to provide 10 minute reserves during a 5 minute period, but not the following 5 minute period, and it was called.

Real Time Imbalance Service

The only change to Real Time Imbalance Service under Option B is that the amount of the product that is needed is only enough to last until the next 5 minute dispatch, rather than until the next 15 minute dispatch. Likewise, bidding and dispatch of RTIS would also be the same under Option B as under Option A.

6.2.3 *Unit Commitment*

One area where there are differences between Option A and Option B is in how they accomplish unit commitment.

- In Option A, Short Term Unit Commitment is co-optimized along with energy and ancillary services in the 15 minute RTED.
- In Option B, unit commitment is done in the Real Time Preliminary Dispatch run every 15 minutes, but this is only used for STUC and it does not establish prices or schedules for energy or ancillary services.

On-Demand Residual Unit Commitment or Short-Term Unit Commitment

- This would be designed to allow commitment of resources with longer start times that might be need for RUC when needed, rather than just once per day following day-ahead integrated forward market.
- The look-out time would be 8-10 hours, allowing consideration of more units.
- The operator could run the on-demand RUC whenever demand forecasts, renewable forecasts or resource availability changes.
- The on-demand RUC would run during the next 15-minute real time economic dispatch under Option A.
- Under Option B, the on-demand RUC would run with the next RTPD.
- The ISO is considering what rules would be required for on-Demand RUC to limit up-lift costs.

6.2.4 *Other Potential Products and Issues*

Market for Automatic Unit Response

- Such a product would ensure that sufficient units are online to provide immediate response to frequency deviations without any ISO direct control. Potentially, this could consist of two separate products:
  - Inertia: to ensure sufficient spinning mass to damp frequency excursions.
  - Frequency Response: to ensure sufficient governor response to arrest frequency excursions prior to AGC response.
- Whether it will be necessary to develop these products will depend on how much of frequency response and inertia are available naturally through the procurement of energy, ancillary services and unit commitment. This may differ in Option A and Option B because of the different amounts of Real Time Imbalance Services that would be procured under the two options.

6.3 Market Design Framework Options Pros and Cons

The ISO believes that both of the options outlined in this paper provide an efficient method for meeting the design objectives while remaining true to the principles that have been outlined above. The new Real Time Imbalance Service common to both options will provide operators with the granularity in dispatch to deal with the increased variability of the system arising from the larger penetration of renewable resources. This structure has the additional benefit of dividing ancillary services into two products and markets, one for fast ramping resources (regulation) and one for slower ramping units with an ability to provide the power for longer periods (RTIS). Before discussing these common benefits of the two options, the paper will provide a discussion of the various pros and cons of the two options, retaining the 5 minute dispatch used today, or changing the Real-Time Economic Dispatch and pricing interval to 15 minutes. By presenting two options, it should be clear that the ISO has not yet determined which option it feels is superior. The ISO continues to be open to other design options and is looking towards the comments of stakeholders as to which Option (or other option) they believe best suits the future needs of the market.

6.3.1 *15-minute or 5 minute real time economic dispatch and prices*

The ISO considered shorter periods for setting prices in the Real Time markets to provide the operators with improved granularity in dispatching resources to meet the needs of the system in a world of increasing amounts of renewable resources, both distributed and connected to the transmission grid, which leads to increased variability in the system. As explained in the next section, the ISO believes that the increasing granularity in dispatch control is best achieved by the creation of a new ancillary service product, Real Time Imbalance Service. This solution is preferable to reducing the dispatch interval to under 5 minutes due to numerous technological and implementation issues. The settlement process for a market with prices changing every minute or two would be much more complicated than today's 5 minute model. Further, running a full dispatch every minute would require a security constrained dispatch that could assess the current state of the market, run the economic dispatch and deliver prices and schedules to market participants fast enough to allow them to respond. In addition, a one minute RTED would require all generators to be able to respond to one minute dispatch instructions. For these reasons, the ISO believes that either leaving RTED at the current 5 minutes, or extending it to a 15 minute RTED are the best options.

6.3.1.1 The Benefits of 5 Minute Markets

The first, and most obvious benefit, of a 5 minute market is that the ISO already has software and systems in place to deal with a 5 minute market. The implementation costs and time for the ISO and all market participants would be minimized by retaining the current 5 minute market structure. The current operating systems, as well as the settlement systems, are all designed around the 5 minute market. Change to a 15 minute market and real time price would require potentially costly and time consuming revisions to both the operations and settlement systems. The ISO is investigating how difficult such changes would be to implement, and is seeking comments from stakeholders as too how hard it would be for them to move from the current 5 minute market to a 15 minute market.

The 5 minute market also has the operational advantage of a shorter time period until the dispatch of the entire system can be modified to respond to an event. With 5 minute dispatch, the worst case dispatch scenario is that adjustments from an RTED run would not begin to take effect for 12.5 minutes, and would not be fully implemented until 17.5 minutes from the event. The worst case would occur if an event were to occur just after the state estimator runs to begin the

RTED process for the next five minute period (7.5 minutes before the start of the period). In this case, 5 minutes must pass until the next run starts and the event can be incorporated in the RTED. The RTED is for the period 7.5 minutes, or over 12.5 minutes from the event to the time period. Given that the state estimator runs early and ramping starts 2.5 minutes ahead and ends 2.5 minutes into that period, we get the 12.5 to 17.5 minute time period. For a 15 minute RTED, a similar analysis of the time to respond would be increased to 30 to 45 minutes. Under the 15 minute market structure, operators are potentially over half an hour away from the RTED addressing a system event.

Even if the operational challenges of being potentially over 30 minutes away from market responsiveness are not an insurmountable issue, the amount of the Real Time Imbalance Service that will need to be procured to ensure reliable operation of the grid would be greater than under a 5 minute dispatch structure resulting in potentially higher costs.

6.3.1.2 The Benefits of 15 Minute Markets

One of the major benefits of moving the real time markets to 15 minutes is that this allows the co-optimization of all markets for energy, ancillary services, and unit commitment. As mentioned above, the similarity of ancillary service products to unit commitment means that even if ancillary services could be co-optimized with energy in a five minute RTED, the fact that there would still need to be some Short Term Unit Commitment process that would not be co-optimized has the potential to create inefficiencies in the system. In a 5 minute market, the STUC run would co-optimize energy, ancillary services, and unit commitment, but would then discard the energy and ancillary service schedules and any price information. These elements are then re-created in the shorter RTED run, taking as a constraint the unit commitment adopted in the STUC run. This extra step, and additional constraint in the RTED, is what the ISO believes has the potential to create inefficiencies that are not there under the proposed 15 minute market structure.

One of the major issues that the ISO seeks to address with this market vision is the shortage of ramping capability currently seen in the real time market. These real-time energy price spikes are generally caused by insufficient ramping capacity due to not enough units being committed during the short term unit commitment process which occurs in the Real Time Preliminary Dispatch (RTPD) run. By moving the dispatch to a 15 minute interval and co-optimizing the energy dispatch, ancillary services and unit commitment, this problem should decrease significantly. With a 15-minute dispatch, peaking plants which can come on line in 10 minutes are able to participate in the real time market without having been previously started in a unit commitment run. Thus, when there is no shortage of capacity or ramping capability in real time, any price spikes that occur would truly be the result of energy shortages, not just a shortage of ramping capacity due to insufficient unit commitment.

There is a cost to mitigating potential ramping shortages, and that is that sufficient resources will now need to be committed in ancillary service markets to provide the operators the needed ramping capacity to support the system until the results of the next 15 minute RTED can begin to take effect, which could be 30 minutes away. With the existing 5 minute markets, this means that regulation needs to be able to meet the ramping needs of the system until the next 5 minute dispatch, which similarly might be 10 minutes away. The proposed ISO market Options A and B both attempt to minimize these costs. First, by creating a new product, Real Time Imbalance Service, which is dispatched every minute, the amount of regulation that will need to be purchased will be decreased, and it will be replaced with this new product. Under the 15 minute dispatch in Option A more of the combined regulation and RTIS will need to be purchased than is currently purchased for regulation, but since RTIS only requires one minute dispatch, not the 4 second AGC response required of regulation, it is expected to be priced lower. As mentioned above, more RTIS would need to be purchased for the 15 minute RTED, Option A, than would need to be purchased under Option B. However, because units self select to provide this service, those units (or parts of units) that are providing RTIS are those that can most efficiently adjust their output. Those units that cannot efficiently adjust their output only need to adjust their output every 15 minutes under Option A, rather than every 5 minutes as would be the case under Option B. By establishing a market for flexibility, rather than requiring it from all units that may or may not respond, the overall efficiency of the grid should be improved.

Other methods, such as some type of ramping constraint used in the RTPD, might also be able to reduce the occurrence of shortages of real time ramping capability, but would do so by modifying the unit commitment to have more units running. This would impose a potential inefficiency on the system as additional units are started and required to be paid their start-up and minimum load costs, and potentially left to operate at minimum load. Additionally, other units will be dispatched at inefficient points to retain ramping and these units will likely need to be compensated for providing this service. Thus, while moving to a 15 minute dispatch may require more ancillary service procurement, keeping the 5 minute dispatch, but making adjustments to avoid ramping shortages, would also require increased procurement of resources through the number of resources committed in the short term unit commitment run. Creating a new ancillary service product that can be co-optimized with energy, other ancillary service products, and the unit commitment process may be a more efficient method of achieving sufficient ramping capability than imposing additional constraints on the optimization without directly taking into account the costs of modifying the dispatch.

Another consideration which the 15 minute RTED likely addresses better is coordination with other Balancing Authority Areas. One of the major issues the ISO seeks to resolve with this market vision is the problem of price discrepancies due to the need to have intertie prices established in the HASP, while prices for all internal nodes are determined in the RTED. Keeping the RTED at 5 minutes likely means that the ISO would continue to need some sort of HASP to schedule imports and exports with the other BAAs in the west. Or at the least, the timing of determining import and export schedules will be in a time frame that is not aligned with the price and dispatch of the rest of the real-time market. Moving to a 15 minute RTED makes it more likely that all prices could use this RTED. FERC is considering whether to require all BAAs to move to 15-minute scheduling. Should this occur, other BAAs may have to accept 15 minute intertie scheduling. Even if other BAAs have not moved to 15 minute scheduling, the ISO having 15 minute scheduling would likely act as an inducement to move to 15 minute intertie schedules. In the event that other BAAs retain hourly scheduling for some period of time, the ISO having 15 minute scheduling and pricing would seem to increase the likelihood that these BAAs would move to 15 minute scheduling. The ISO could accommodate hourly schedules under the 15 minute RTED structure by treating hourly intertie schedules as a self schedule, or allowing interties to submit a bid for the first 15 minute period in an hour, but then be a price taker for the remaining 3 period in the hour. Eliminating HASP, and the price discrepancies that arise from having some prices established in HASP, is a strong reason for moving to a 15-minute Real Time Economic Dispatch (RTED) period. It seems plausible that other balancing authorities in the west will move to 15-minute scheduling at some point in the future as a result of increasing supply variability on the western grid. Further, while it may be possible to compress the check-out and tagging process to a 15-minute schedule when all balancing authorities schedule on a 15-minute basis, there may not be enough time to accommodate more granular scheduling (i.e., a 5-minute schedule) and still allow for these important administrative processes.

Moving to a 15 minute RTED has other timing benefits as well. It would allow renewable resources, or other variable energy resources, to schedule their energy every 15 minutes. Scheduling on a 15 minute basis would be possible for the ISO and we assume for many of these resources, but moving this up to every 5 minutes or even less may result in implementation issues. Giving more granularity to scheduling for these resources should help decrease the impact of their variability on the system. In a similar manner, 15 minute real time prices may facilitate the responsiveness of demand and the implementation of dynamic pricing at the retail level. Instead of responding to prices moving every 5 minutes or less, these programs would see prices change only 4 times an hour and have slightly more lead time in which to adjust.

6.3.2 *New Ancillary Service: Real Time Imbalance Service*

The ISO believes that creating an additional ancillary services product helps to rationalize and improve the efficiency of the markets. Real Time Imbalance Service will provide the ISO with resources which can be dispatched on a minute by minute basis to balance the grid between the runs of the full RTED. This element is part of both Option A and Option B that the ISO is putting forward. RTIS will reduce the need for regulation because its one minute dispatch allows for regulation to be reset to its null point every minute instead of every 5 minutes as is currently done.

One benefit of creating this new product is that this will allow units to self select into different categories and provide those services for which they are best fitted. The ISO and others have recognized that there may be differences in the abilities of various types of resources to provide what is known as regulation today. The ISO is attempting to allow new resource types to participate in the markets through its Regulation Energy Management proposal. Creating RTIS establishes two different ancillary products, one which is for units that can respond very quickly (with seconds) but are then reset to their null point every minute so that they don't require much capacity. This would be similar to a fast ramp unit, or the units that would be accepted under REM. Other, more traditional resources, which can respond to instructions but on a slower basis, will be expected to provide the new product, RTIS. Having two markets for two different products is likely more efficient than having one market and trying to figure out how to price differently within the same market. As discussed above, this structure also allows resources to choose not to be moved except in the RTED. These units would have their schedules determined over either 15 minute periods (Option A) or 5 minutes (Option B). Units will self select into the categories that they can best provide and where they will make the most money.

Creating the Real Time Imbalance Service product will also allow us to redefine the regulation product. In addition to the changes mentioned above, under either ISO Option, regulation would be procured as MW/min, rather than the MW method of today. This will allow the resource to focus on the ramping capabilities within the minute, which is what regulation is designed to do. This will improve efficiency in the market by allowing resources which are more valuable because they can ramp very quickly to receive larger awards than slower resources.

Another potential benefit that the ISO is evaluating is the ability of RTIS to serve as a measure of the cost of balancing or variability on the ISO system. The costs of RTIS are essentially a measure of what the ISO has to pay to secure sufficient resources to deal with the variability that arises because market participants' production and/or usage differs from what was scheduled for them in the RTED. If all market participants were able to keep their load and production exactly at what was scheduled for them in the RTED there would be no need to procure RTIS. This suggests a simple and elegant solution to the question of how the costs of variability might be allocated. The costs of the variability could be measured as the total costs of this new ancillary service, RTIS, and the allocation could be based simply on a measure of how each market participant deviates from its RTED schedule. This mechanism has a simple measure of the costs of variability and a simple way to measure the variability of all market participants. Load is treated exactly the same as generation, and renewable generation is treated exactly the same as all other generation. Alternatively, the cost of RTIS could be allocated on a load ratio share to all load serving entities. The ISO is very interested in getting stakeholder input on this cost allocation issue.

Either Option of the ISO Straw Proposal could allow variable energy resources to schedule on more granular level (for example, under Option A, VERs could submit schedules every 15 minutes), thus giving them the similar opportunities as other generation, which is given its schedule in the RTED. This structure creates the proper incentives for VERs to consider options for limiting their variability. They can choose to have the ISO provide balancing services by continuing to operate as they do today and paying for their appropriate share of the balancing costs. Alternatively, if it is less expensive, they could adopt technologies that would limit their variability and thus decrease the costs of balancing services they are allocated by the ISO. This structure provides price signals so that they can properly evaluate their options and make the most efficient choices. For example, it might be cost efficient to install software that helps control ramps and smoothes out some of the variability, but not cost efficient to install storage technologies which would completely remove the variability. In this hypothetical example, the price of the software is less than the cost of ISO balancing, but the ISO balancing is cheaper than the cost of installing storage.

Similar incentives apply to load. To the extent that a LSE can find methods to control the variability of the load it supplies, it would limit its costs for balancing. As with the VERs, the LSEs would have the prices and information to make efficient decisions about whether various new technologies should be adopted or not. Such a market structure would help encourage the adoption of new technologies when and where they are cost efficient. Should these technologies have other benefits that deliver additional revenue streams, accurate information about their value in limiting variability will allow market participants and policy makers to determine whether they are the least costly method of providing the various services.

Under such a proposal for allocating variability cost, the ISO does not propose that regulation be part of these costs. Under either Option of the ISO's straw proposal, regulation deals only with very short run fluctuations, as has historically been the case. These short term fluctuations would be assumed to be caused mostly by load varying – i.e. they are due to customers turning on and off appliances. In this proposal, the ISO would continue to allocate the costs of regulation (although now a newly defined regulation) only to load. The ISO explicitly seeks stakeholder comments on this specific aspect, as well as this whole possible method for identifying and allocating the costs of variability.

6.4 Summary

In summary, the ISO believes that both Options of the Straw Proposal described in this paper would provide a reliable, robust, and efficient market structure. Both Options would provide operators with sufficient units to dispatch to meet the increased variability expected with larger numbers of renewable resources, while providing market processes that allow market participants to evaluate different options for providing services and make efficient choices. In addition to general comments on all aspects of the two Options of the Straw Proposal, the ISO specifically seeks stakeholder input as to whether real time prices and scheduling should continue to be done on a 5 minute basis, or whether changing the real-time scheduling and price to a 15- minute period would provide a more robust market structure and be better for market participants. The ISO is also very interested in getting stakeholder feedback on the implementation issues/costs associated with each of these options as this will be an import consideration in deciding which option to adopt.

7 Stakeholder Process and Timing

7.1 Process Timeline Overview

7.2 Stakeholder Process for 2011

Table 1 below outlines the stakeholder process associated with this initiative. The ISO will post a series of papers starting with the day-of market vision, followed by a day-ahead and forward market vision. The paper series concludes with a final renewables integration market vision and roadmap for presentation and review by the ISO Board on December 15-16, 2011.

Table 1: Renewables Integration Market Vision and Roadmap Initiative Schedule

Schedule	Item
Jul 6, 2011	ISO post initial day-of market straw proposal
Jul 11, 2011	Stakeholder meeting to discuss initial day-of market straw proposal
Jul 22, 2011	Stakeholder comments due on initial day-of market straw proposal
Aug 3, 2011	• ISO post revised day-of market straw proposal • ISO post initial day-ahead and forward market straw proposal
Aug 10-11, 2011	• Two-day stakeholder meeting: • Day-of market: Aug 10 • Day-ahead & forward market: Aug 11
Aug 25, 2011	Stakeholder comments due on day-of and day-ahead and forward market
Sep 8, 2011	• ISO post draft final day-of market proposal • ISO post revised day-ahead & forward market straw proposal
Sep 15, 2011	Stakeholder meeting to discuss proposals
Sep 29, 2011	• Comments due on draft final day-of market proposal • Comments due on revised day-ahead and forward market straw proposal
Oct 13, 2011	ISO post draft final market vision & roadmap
Oct 20, 2011	Stakeholder conference call to review draft final market vision & roadmap
Oct 27, 2011	Comments due on draft final market vision & roadmap
Nov 4, 2011	Final market vision & roadmap published
Dec 15-16, 2011	CAISO Board review and presentation