California ISO

Shaping a Renewed Future

California ISO

Discussion & Scoping Paper on Renewable Integration Phase 2

Renewable Integration: Market and Product Review Phase 2

April 5, 2010

Issue Paper - Phase 2 Renewable Integration

Table of Contents

1 Introduction

Over the past several years it has become clear that dramatic changes in the electricity sector will need to occur as a result of new public policies and regulations to reduce the environmental impacts of power production. Environmental policy is directly driving changes in the composition of the supply fleet – mainly to increase the contribution of renewable resources and decrease reliance on fossil fuel resources – which in turn presents new operational challenges, affects spot market outcomes (schedules, prices, revenues), and creates needs for new transmission infrastructure. Moreover, California's adoption of the 33 percent renewable portfolio standard ("33% RPS"), requiring that 33 percent of the state's electricity consumption be supplied from renewable resources by 2020, allows a relatively short time frame for the industry to adapt to these changes, while the expected magnitude of the changes requires that the adaptations be designed carefully, from a whole-system perspective, and cost-effectively.

Against this backdrop the ISO has already undertaken several initiatives to design, develop and implement needed changes in areas of its core responsibilities. Among other things, in July 2010 the ISO initiated the "Renewable Integration: Market and Product Review" ("RI-MPR"), a stakeholder process to identify and develop potential changes to wholesale market design, including new market products and market rules to accommodate the expected substantial increase in production by variable energy resources (VER) over the next decade and address the expected revenue challenges that may face conventional resources needed to support integration of renewables. The RI-MPR was designed to be conducted in phases, so that near-term operational needs could be addressed first, followed by market enhancements to address medium- and long-term needs. Phase 1 of the RI-MPR was begun in July 2010[1] and is now nearing completion; Phase 2 is hereby initiated with the present scoping and discussion paper.

The ISO envisions two major objectives for Phase 2, and provides this paper to stimulate stakeholder discussion of these objectives and how best to achieve them. First, the ISO seeks to develop a comprehensive framework or "roadmap" for the market changes that will need to be designed and implemented over the next several years. Such a roadmap should take a longer-term view to identify the most effective and robust solutions to the new challenges and requirements rather than the most expedient or easy to implement, as well as a holistic view that takes into account the interactions between distinct market elements and rules. Such a roadmap should offer a vision of a well-functioning market end state, as well as a plan for getting there through a logically staged process for developing and implementing the component elements. The ISO believes that such a roadmap can and should be completed as a Phase 2 objective by the end of 2011.

The second objective is to target specific market design changes or new market elements for completion, including approval by the ISO Board, by end of 2011 or early 2012. The ISO invites stakeholder input to help identify, from among the range of topics raised in this paper or others that stakeholders could propose for inclusion, a set of specific needs and issues that need to and logically can be addressed earlier rather than later, and that together would be feasible to complete in this time period.

[1] Phase 1 is addressing a number of near-term incremental changes to market design to improve operational capabilities to support integration of renewables: reduction of the energy bid floor; refinements to the Participating Intermittent Resource Program (PIRP); limited modifications to bid cost recovery; and adoption of Regulation Energy Management (REM). The ISO's *Revised Straw Proposal for Phase I* is posted on the ISO website at http://www.caiso.com/27be/27beb7931d800.html

Following the stakeholder meeting to discuss the present paper and the ISO's receipt of written comments, the ISO will post a second issue paper that (1) provides a preliminary outline draft of the proposed comprehensive market design roadmap, laying out the intended scope of the roadmap without trying to fill in the substantive content that will be developed with stakeholders over the next several months, and (2) discussion of the high-priority topics identified for resolution by late 2010 or early 2011, including identification of the policy and design issues to be addressed and some of the options for consideration.

The remainder of this paper provides:

- A survey of market design elements and issues that the ISO proposes to consider for inclusion in the first objective, the comprehensive roadmap described above, without any attempt to identify which of these should comprise the more focused design effort to be conducted for the second objective.
- A review of relevant market design elements that have been adopted by other ISOs and RTOs in the country.
- Proposed timetable for this initiative and some immediate next steps.

2 Candidate Elements for the Comprehensive Market Design Roadmap

2.1 Background

The California ISO and other ISOs/RTOs will examine and implement a range of measures over the coming years to adapt the wholesale energy markets to the operational requirements of renewable integration. A number of significant market and operational changes could take place more or less concurrently, depending both on the quantity of renewable production as well as the particular mix of renewable resources and their locations.

A number of trends appear to be inevitable. First, renewable energy will largely be displacing in-state gas production in the California power system. The degree of that displacement will be a function of the mix of in-state and out-of-state renewable resources and the degree of dynamic scheduling of external resources.[2] The degree of displacement is also a function of the method and quantity of balancing capacity that will be necessary to support high level of renewable integration. The ISO's 20% RPS integration study showed that the displacement due to the combination of wind and solar causes the "net load" – load minus wind and solar production – to affect gas production across the day.[3] With a 33% RPS, on some days up to 50% of energy during the peak hours may be renewable (assuming high in-state development of solar resources). Hence, solar production may substantially displace gas-fired peaking units.

Second, while renewable resources displace gas generator production, the gas fleet committed to provide energy and ancillary services will face an increasing number of starts and stops and will operate more often at minimum operating levels, compared to a benchmark scenario that does not include incremental renewable production. For example, the production simulations

[2] Out of state resources that are firmed and shaped may displace other energy imports and thus have a less significant impact on in-state operations.

[3] See 20% RPS Study http://www.caiso.com/2804/2804d036401f0.pdf pg xiv

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. That study also found that steam plants and gas turbines are expected to operate less often and have fewer starts. However, as system variability increases with as we move toward the 33% RPS, the ISO will likely need to procure additional reserves to provide load-following services. As this occurs, peaking conventional units may be needed more often to provide load-following service and incur an increased number of starts and stops.

Third, wholesale energy prices will be affected in different ways by the new system conditions. First, significant renewable penetration will lead to a reduction in energy market prices in certain hours compared to what those prices would have been. Off-peak prices, for example, are expected to be reduced due to the higher wind production in those hours. How wind and solar production will affect on-peak prices will depend on the production efficiency of the gas plants being displaced from the peak hours. In addition, real-time prices overall will become more volatile, reflecting the variability in actual production by wind and solar in real-time.

Key findings of the *ISO 20% RPS Study* indicate that in order to successfully integrate renewable resources the ISO will need increased operational flexibility. This will require additional ramp, load following and ancillary services capabilities from both generation and non-generation resources. There will also likely be higher frequency and magnitude of over-generation conditions.

The ISO expects initial results of the 33% RPS study to be available during the second quarter of 2011. While this study will provide more details around the quantities of load following, regulation, ramping capacity, etc., needed to support the integration of variable energy resources; the 20% studies provide significant information on which to begin informed discussions with stakeholders on what types of changes to market design are needed.

Given these concurrent market and operational impacts, the ISO seeks to consider as part of this initiative both 1) near term changes to existing market design that may provide the ISO with additional operational flexibility, as well as 2) longer term market design changes in the form of new spot market products and forward capacity products that will provide the ISO the needed operational characteristics from the resource fleet to integrate variable energy resources successfully.

2.2 Enhancements to Existing Market Design

This section discusses potential changes to the existing market structure that could provide the ISO with additional operational flexibility to aid with the integration of renewable resources**.** These enhancements are currently listed in the Market Initiatives Catalog and were ranked “medium” in 2009 through the last round of the ranking process.

2.2.1 Hourly Contingency-Only Election for Operating Reserves

Currently, due to software limitations, the contingency only designation for spinning reserve and non-spinning reserve must be for all 24 hours of each operating day. There is no ability to designate contingent or non-contingent reserves on an hour by hour basis. In addition, all incremental operating reserves procured in HASP or the RTPD are by default contingency only. This means that the ISO may dispatch these contingent reserves only when contingency conditions occur such as an unplanned outage, transmission contingency event or an imminent or actual system emergency. By providing hour by hour flexibility to the contingency-only election the ISO could have more ancillary services capacity available to dispatch economically to address real-time imbalance energy requirements and other system conditions such as ramping constraints that will likely be more unpredictable with large quantities of intermittent resources under the 20% and 33% RPS.

2.2.2 Multi-Settlement System for Ancillary Services

The existing market procures Ancillary Services in the day-ahead market to meet 100% of forecasted real time needs, and then procures additional A/S incrementally in real time only to the extent that they are needed due to changes in system conditions, loss of resources previously awarded AS, or demand exceeding the day ahead forecast. Currently, market participants do not have the ability to buy-back ancillary services they were awarded in the Day-Ahead market. Looking into the future where there will be more variability in real-time due to large volumes of renewable resources participating in the ISO markets, it may be beneficial to consider a multi-settlements system for ancillary services to provide more flexibility for the ISO and provide market participants with the ability to buy back and sell ancillary services closer to real-time.

2.2.3 Enhancements to RUC

An aspect of RUC design that the ISO may want to examine as it prepares to accommodate a 33% RPS is how RUC will evaluate generation resources to ensure that there is enough capacity online, or available within a sufficiently short time frame, to avoid involuntary load shedding if the output of intermittent generation is significantly lower than the amount cleared in the day-ahead market. Hence, one element of the RUC design that needs to be evaluated is the methodology regarding wind and solar output assumptions that the ISO will use during RUC to assess whether enough capacity has been committed to meet the ISO's load forecast. The ISO's business practice manuals generally state that the ISO will make adjustments for differences between the amount of energy cleared in the IFM from intermittent resources and the ISO's forecast of their output, but the ISO may need to revisit how it determines these adjustments in light of larger volume of renewable resources coming online.

As the level of intermittent resource output increases in future years, it may not be sufficient to simply adjust the RUC for the difference between the ISO's forecast of expected intermittent output and the amount of intermittent energy cleared in the day-ahead market. On the one hand, as the level of renewable output becomes larger, the magnitude of the potential forecast error (i.e., the potential difference between the actual and expected output) may become so large relative to the scheduled reserves that the ISO will need to account for the magnitude of this potential difference in the RUC commitment. At the same time, a conservative approach of running RUC based on an assumed low level of intermittent resource output in all hours of the day may greatly overstate the amount of energy required from energy limited resources, such as hydro, leading to the commitment of excess thermal generation in the RUC.

A second element of the IFM/RUC commitment logic that the ISO and stakeholders might re-evaluate is how the ISO should best ensure that it has enough ramp capability committed to accommodate the intra-hour variability of renewable generation output. This is conceptually distinct from the capacity question above, because it involves commitment of enough rampable generation to handle the potential level of variation in output within an hour, including downward ramp. One of the topics that should be considered is whether this evaluation is best structured within the IFM, within the RUC process, or potentially in a new market process.

Another issue to consider is whether or not performing RUC and IFM simultaneously would provide benefits as the ISO moves towards higher volumes of renewable resources. Currently, the ISO manages RUC in a sequential run that clears against the ISO load forecast after the IFM has concluded. Simultaneous RUC and IFM would reflect the ISO's requirements to have sufficient capacity and import energy available to operate the system in real-time as part of the day-ahead prices. This approach may also provide the ISO with more tools to address over-generation conditions. For example, the current RUC design is not able to de-commit units when too much capacity was committed in the IFM run relative to the load forecast, whereas a simultaneous IFM and RUC would avoid this problem. While this more efficient unit commitment may provide benefits, it would not be a simple change to implement; the ISO believes therefore that more discussion is needed to determine if this enhancement provides enough benefits to be considered a higher priority over other enhancements needed to support renewable integration.

2.3 New spot market products

2.3.1 Pay for Performance Regulation

The 20% RPS study identified a need for additional regulation capacity particularly in the evening and morning ramp hours. For example in the summer season, the total simulated requirement of regulation up in 2012 (the total MW of the values plotted in the frequency distribution for 2012) as compared to 2006 was 37% greater. For regulation down the simulated requirements showed to be 11% greater than 2006[4].

In the stakeholder initiative on Regulation Energy Management (REM), the ISO committed to explore further enhancements to regulation products as part of this Phase II initiative. Resources that more accurately follow AGC signals can reduce the amount of regulation the ISO must procure to meet system needs which could provide long-term cost benefits by eliminating or reducing the need for the ISO to increase ancillary service procurement targets due to intermittent resource penetration. Therefore, the ISO is considering a pay for performance product. The ISO also evaluated what the other ISOs are doing in regards to pay for performance regulation which is described in Section 3 of this document. In addition, FERC also issued a NOPR which is explained in the following paragraphs that proposes to change the rules for how ISOs compensate resources providing regulation.

On February 17, 2011, FERC issued a notice of proposed rulemaking (NOPR) to address undue discrimination in the procurement of frequency regulation service (regulation) in organized wholesale electricity markets. The rules proposed by FERC would change how the ISO compensates resources providing regulation.[5]

FERC asserts that faster ramping resources provide more Area Control Error (ACE) correction to system operators than slower ramping resources but do not appear to receive compensation

4 See 20% RPS study, pg 52, table 3.3 at: http://www.caiso.com/2804/2804d036401f0.pdf

5 Regulation is used to control the energy output of generating units within a prescribed range in response to changes in system frequency, tie-line loading, or the relation of these to each other so as to maintain the target system frequency and/or the established interchange with other balancing authority areas within predetermined limits. The ISO's AGC system issues instructions every four seconds to each resource providing Regulation to help assure that CAISO balances demand and supply between five minute real-time dispatch intervals in the ISO Balancing Authority Area in accordance with NERC and WECC operating criteria.

for the service they provide. FERC states that certain ISOs and RTOs net regulation up and regulation down energy payments provided by resources and this compensation method does not acknowledge the greater amount of ACE correction provided by faster ramping resources. FERC is concerned that slower ramping resources may receive the same compensation as faster ramping resources under a netting approach even though the faster ramping resource provides more ACE correction to a system operator during a market interval. FERC also states that some ISOs and RTOs dispatch faster ramping resources earlier than slower ramping resources yet pay all resources the same rate for capacity and the same price for MWh of net energy. FERC's concern indicates that such compensation approaches may be unduly discriminatory to faster ramping resources. The ISO seeks comments from stakeholders on issues raised in FERC's NOPR as part of phase 2 of its renewable integration market and product review.

FERC Compensation Proposal

FERC proposes to require all resource bids to include opportunity costs and that all cleared bids for regulation receive a single market clearing price that reflects the total marginal costs of the marginal cleared resource.

FERC proposes that ISOs and RTOs change their tariffs so that regulation resources receive a two-part payment.

Two-part Payment

FERC proposes a two-part payment structure for regulation that would include a capacity payment and a performance payment with an accuracy adjustment.

Capacity Payment

FERC proposes that regulating resources receive a capacity payment to hold capacity in reserve and not participate in the energy market. The payment must include the marginal regulating resource's opportunity costs and the ISO or RTO must calculate cross-product opportunity cost resulting from not participating in the energy market.[6] Where appropriate, FERC also states that resources should be permitted to include inter-temporal opportunity costs in their capacity bid (i.e. the foregone value if a resource must operate at one time and forego a profit from selling energy at a later time or incurring costs to consume energy at a later time).[7]

Under the ISO market design, the ISO co-optimizes energy dispatch and reserve procurements in both the day-ahead market and the real-time market allowing a regulating resource within an ancillary services region to earn the marginal resource's opportunity cost, which also reflects cross-product opportunity costs.

The ISO currently co-optimizes energy and ancillary services over multiple intervals. The ISO solicits comments on whether its capacity payments for regulating resources should also include inter-temporal opportunity costs. For storage devices, the inter-temporal opportunity cost represents the value that the resource forfeits to provide regulation up or regulation down

---

[6] FERC Order 745 at pg. 23, FN 49 FERC indicates that the cross-product opportunity cost is the revenue a regulation provider loses because it is on stand-by to provide regulation and is not providing energy.

[7] FERC Order 745 at pg. 23, FN 50 explains that the inter-temporal opportunity cost is the trade-off presented to a thermal storage operator who would prefer to charge when prices are low. If such a resource were to provide frequency regulation, it could be asked to stop charging during low price periods and then be forced to charge during high price periods.

because it will have less flexibility to use its capacity for energy charging and discharging and take advantage of energy price differences between intervals. To reflect inter-temporal opportunity costs, the ISO would need to build additional constraints into the ISO optimization algorithm. The ISO seeks specific proposals on how it would account for inter-temporal opportunity costs in capacity payments for regulation for both storage resources and conventional resources.

Issues to Consider- Capacity Payment

- Is there a minimum required amount of stored energy for a given interval of time for a storage device to qualify to provide regulation service?
- In real-time, should resources awarded to provide regulation in subsequent intervals be disqualified from providing regulation in subsequent intervals if the resource's stored energy falls below a minimum energy threshold due to energy releases in previous intervals?
- How would the ISO account for inter-temporal opportunity costs in the price of regulation energy for a storage device given the price could be different than the price of regulation energy provided by a conventional resource due to potential inter-temporal constraints applied only to storage?

Performance Payment with Accuracy Adjustment

FERC proposes that regulating resources receive a performance payment based on the amount of up and down movement, in megawatts, a resource provides in response to the ISO/RTO AGC signal. FERC proposes the payment should also incorporate a resource's accuracy in following the AGC signal to provide ACE correction.

A performance payment with an accuracy adjustment allows for resources that respond accurately to an AGC signal to receive greater compensation than resources that do not respond accurately. Historically, the ISO has qualified and compensated regulation resources for their ability to respond to an AGC signal; however, FERC is suggesting that the "quality" of regulation service provided is worthy of compensation beyond simply a resource's capability to provide regulation.[8]

Mileage payment

In addition to a capacity payment, FERC proposes that ISOs/RTOs compensate regulating resources with a mileage payment. A mileage payment would provide greater compensation to a resource that is able to perform more work, i.e. can travel a greater distance in a set amount of time relative to another resource. Under a mileage payment, FERC proposes that the ISO would sum the total absolute value of a resource's up and down movement multiplied by the price per MW of ACE correction.

FERC proposes that the mileage payment reflect bids in the form of a price-per-MW of ACE correction ($/MW-ACE Correction). Under FERC's proposed rule, the ISO would determine the least cost set of resources based on available capacity, ramp rate, and price-per-MW ACE correction, thereby establishing the final ancillary service marginal price for regulation on the marginal regulating resource. The price-per-MW of ACE correction would be a separate and

[8] The ISO's Regulation non-compliance program only rescinds Regulation capacity payments when the quantity of Regulation capacity is non-compliant. The ISO Regulation non-compliance program does not measure the accuracy of a resource responding to the AGC signal. (CAISO BMP for Compliance Monitoring, pg. 36.)

distinct bid from a resource's regulation capacity bid. In the alternative, if a market solution is not workable, FERC suggests the mileage rate could reflect an administrative rate.

Accuracy adjustment

FERC proposes that ISOs and RTOs measure the accuracy of a resource using currently available telemetry and that a resource only receive payment for regulation energy that actually corrects ACE. FERC states that there is little consensus concerning how to incorporate regulation accuracy into wholesale electricity market designs.

The ISO solicits comments from stakeholders concerning developing mileage payment for regulating resources that includes an accuracy adjustment. Specifically, the ISO requests in put on the following questions:

Issues to Consider- Performance Payment with an Accuracy Adjustment

- Does the fact that the ISO procures regulation up and regulation down as separate services have an impact on how the ISO would implement a performance payment?
- Are there minimum threshold performance standards to be eligible to receive a performance payment?
- Is there a correlation between fast ramping and accuracy? For instance, can a single fast ramping regulating resource be more accurate in satisfying ACE correction than several slower ramping regulating resources?
- How would stakeholders define accuracy? Should physical constraints of certain resource types be considered in an accuracy adjustment? For example:
    - For a hydro generator, after sending out a "raise" MW command, the MW output will lower before moving up to the target level. This is a characteristic of a hydro generator.
    - A fast ramping rate does not always mean fast response over a short time period even though there may be a correlation. Time constants of certain resource types, e.g. turbines, play an important role in response times over short periods. Do such time constant constraints impact the ability of turbines to accurately follow an AGC signal?
- How might the ISO apply an accuracy adjustment?

Net Energy

FERC questions whether net energy should be maintained in ISO and RTO regulation markets in light of its proposed two-part payment compensation method described above.

The ISO calculates the regulation energy provided from the two 5-minute dispatch intervals over a 10-minute settlement interval. The ISO solicits comment on whether establishing a mileage payment would make the netting of energy across the settlement interval a moot point.

Conclusion

The ISO looks forward to engaging stakeholders in policy and technical discussions concerning the potential development of compensation approaches for regulating resources. Ultimately, the ISO wants to establish policies and market based incentives that will enable and encourage resources to more accurately follow the ISO AGC signal. Monetizing performance and accuracy to address ACE correction could assist the ISO with integrating greater amounts of variable energy resources and could encourage new types of regulating resources. However, all benefits must be weighed against their cost, and so the ISO will seek input from stakeholders on costs and benefits of compensation methods and any related cost allocation concerns.

2.3.2 Load Following Reserve

A key finding of the 20% RPS report was that load following requirements will increase substantially in some hours. A load-following requirement is defined as unloaded upward dispatch capability and unconstrained downward capability in the units committed through the day-ahead market and real-time market procedures to meet the schedule deviations in real-time by load and variable energy resources. As noted in the 20% RPS report, the ISO currently has no explicit load following requirement constraint but rather balance system needs through unconstrained dispatch capability available through current market procedures. Without an explicit load following constraint, if imbalance conditions change due to load and supply deviations more than the available capability is able to follow, imbalance shortages will arise and the ISO will have to lean on regulation resources or others in the interconnection to balance system needs. At the same time, some of the changes currently in progress such as the flexible ramp constraint will effectively better ensure sufficient load-following capacity. The 33% RPS study will provide more information as to additional quantities needed by 2020 to manage the grid. At some point, under criteria to be considered in this initiative, an explicit capacity reservation may be needed. Once the exact needs are better defined a number of design issues would need to be addressed.

<u>Requirements</u>

Since there is no WECC MORC requirement for a load-following reserve the CAISO and stakeholders would have to determine how and when to set requirements for this new product.

<u>Procurement</u>

The load following reserve could be procured regionally, sub regionally or both. The methodology for procurement would also need to be determined. The following options could be considered:

1) <u>Incorporate procurement with other Ancillary Services in the Day-Ahead clearing process.</u>
This option would allow the load-following reserve to be co-optimized along with energy and other ancillary services bids.

2) <u>Purchase only in HASP after Day-Ahead outcome is known.</u>
This approach would allow the CAISO to determine requirements for load-following reserves after the outcome of the IFM and RUC processes. This could ensure a more accurate determination of the requirements closer to Real-Time.

3) <u>Procure through monthly or annual auction.</u>
It may be more efficient to procure load following reserve on a more forward, longer-term basis, to provide greater day to day certainty to the ISO about the availability of these reserves and to the qualified resources regarding their revenues from capacity payments. Further discussion of this concept is provided later in this paper in connection with a potential forward reserve market.

2.3.3 System Inertia and Frequency Response

As larger volumes of variable energy resources displace more and more synchronous generation, there will be times when the synchronized inertia on the system could have a negative impact on the established stability limits of the system. During high variable energy production levels and low system load (off-peak hours or during weekends or holidays), there may not be enough rotating mass or inertia on the system to arrest frequency decline and/or enough governor response to stabilize the system frequency following a contingency. This could result in under-frequency relays picking up and disconnecting load from the system. How to potentially procure and price this operational need will require further discussion. The ISO is currently working on an intertia study with GE that will provide more insight into the magnitude of this potential concern. The inertia study is planned to be completed at the end of July 2011.

2.3.4 Flexible Ramping Constraint

The ISO has identified a near term operational need to ensure there is enough MW ramping capacity up and down to handle the range of net load[9] variations that can occur within the real-time operating hour. Currently the Integrated Forward Market (IFM) and the Real-Time Pre-Dispatch (RTPD) optimize resources based on a single point-forecast imbalance amount for each interval of the designated time horizon; i.e., each hour of the next day for the IFM and each 15-minute interval for the RTPD time horizon.[10] The optimization assumes both that there is no error in the net load forecast and that system conditions are constant within each interval. There are times when IFM and RTPD optimize resources so efficiently that they leave little on-line available, unscheduled capacity for use by the 5-minute Real-Time Dispatch (RTD) to meet any variation between the constant forecast conditions assumed in IFM and RTPD and what is actually occurring in real time.

Given the nature of these assumptions used in the RTPD, real-time deviations from the net load forecast frequently require the RTD to dispatch capacity that can ramp to the needed target operating level by the next 5-minute interval in order to maintain reliable operation, particularly during hours of high load ramping. When these needs occur and the available supply of ramping capacity is not sufficient, the only tools left for the operator to manage the problem are to bias the forecast and/or issue exceptional dispatch instructions. To provide ISO operators the ability to manage these situations through the RTD market optimization, an additional constraint will be introduced in the IFM, RTPD and RTD optimizations, referred to as the upward and downward System Ramping Constraint (SRC). These new constraints will ensure that the optimization solutions in IFM, RTPD, and RTD make available some un-loaded upward ramping capacity below Pmax and some loaded downward ramping capacity above Pmin on the scheduled, internal, dispatchable, ramp-capable resources. These constraints will effectively ensure that there is sufficient capacity that is available to respond to real-time dispatch instructions and is capable of ramping to manage the variability caused by the changing system conditions and various numerical and forecasting model errors between the IFM, the RTPD and the corresponding RTD intervals that will occur starting roughly 15 minutes after each RTPD.

9 The net load forecast is the forecast of ISO internal load net of the forecast VER energy supply.

10 RTPD looks ahead between four and seven 15-minute intervals to ensure there is sufficient capacity to meet demand over this multi-interval trajectory.

Because of the near-term operational need for the real-time ramping capability these new constraints will provide, the development of the design details of these constraints is not a topic for the initiative discussed in this paper. This initiative will, however, consider how the needs driving the implementation of the flexible ramping constraints could be met through a more market-based approach. The ISO expects that the intra-hour variability that these new constraints are designed to address will increase in the future as more VER are integrated into the ISO system. Therefore the ISO will implement the new constraints as a near-term, interim solution, until the ISO and stakeholders can develop a long-term approach through the present initiative that will appropriately value, procure and compensate the needed ramping service through the market structure.

2.3.5 Reflecting Constraints in Market Prices

In addition to the physical constraints of the transmission system and generation resources, the ISO market optimizations may need to incorporate additional constraints to ensure that reliability requirements are met through market outcomes. The previously implemented Minimum Online Commitment (MOC) constraint and the pending Flexible Ramping Constraint are examples of constraints used to ensure that the market outcome will meet reliability requirements. In both constraints, the issue is that absent the constraint the ISO is not assured that the market outcome will provide sufficient resources to manage identified reliability concerns.

In order to assess the appropriate pricing impact of the constraint, one must determine why the market did not commit the resources necessary to meet the operational requirement absent the constraint binding. Next one must evaluate the economic impact on the resource that has satisfied the constraint and on the other resources participating in the market. Then one must determine which components of the LMP should be impacted when the constraint is binding. Finally, one must determine if and how to price the constraint through either a direct capacity payment (spot market product) or calculation of opportunity costs. There may also be intermediate short-term steps such as paying a resource the shadow price of the constraint while the impact of the constraint is analyzed during actual market operations or a new product is being designed and implemented. Another approach could be to incorporate certain types of constraints into the annual local capacity requirements for Resource Adequacy (RA), so that the needed resources will be procured to meet RA requirements and receive RA capacity payments.

The MOC constraint addresses the operational needs of certain operating procedures that require a minimum quantity of committed online resources located within a defined area in order to maintain reliability. Prior to implementing this constraint, the specific resources were committed outside the market through Exceptional Dispatch. Additional documentation is available in the Technical Bulletin available at http://www.caiso.com/271d/271dedc860760.pdf.

Currently the shadow prices of the MOC are not incorporated directly into any pricing calculations, but if the constraint is regularly binding at high capacity levels it may warrant designing a mechanism to ensure the constraint impacts pricing. Absent this constraint, the specific resources in the defined area are not committed as other lower priced resources outside the defined area will meet system needs while satisfying the objective to minimize overall system costs. When the constraint is enforced, the needed resource inside the defined area is committed at least at its minimum load (PMin). However, if the resource is economic to provide energy above its minimum load the resource will be dispatched above PMin and be eligible to set the price. If however, the resource is not economic above based on its energy above minimum load the resource will not set prices because its energy bid is not cleared in the market. If the resource has a revenue shortfall from operating at PMin it is eligible for bid cost recovery. The impact for some resources outside the defined area is they are not being committed. In addition, the commitment of the needed resource at PMin provides additional price taker supply, shifting the supply curve and potentially resulting in a lower or higher system marginal cost of energy (SMEC) relative to the SMEC without enforcement of the MOC constraint.

In many cases the MOC constraint addresses constraints that are already reflected in the local capacity requirement in the annual Resource Adequacy requirements for the defined area, so that the specific resources committed by the MOC constraint already receive RA capacity payments. However, to the extent an MOC constraint is requiring non-RA resource to be committed, one may question if such non-RA resources have sufficient opportunity to be compensated for their service. The MOC does not lend itself to a spot market product because only specific resources are able to resolve the constraint; however, potentially an opportunity cost could be calculated that reflects the commitment of higher cost resources in the SMEC for all resources.

The Flexible Ramping Constraint is being implemented because the ISO has observed that in certain situations reserves and regulation service procured in the real-time (RTPD and HASP) and units committed for energy in the fifteen minute unit commitment process (RTPD) lack sufficient ramping capability and flexibility to meet conditions in the five minute market interval. The issue can be addressed in part by enforcing the Flexible Ramping Constraint to ensure that sufficient upward and downward ramping capability of dispatchable resources is committed to enable the real-time dispatch (RTD) to follow load efficiently and reliably over an estimated range of potential variability of net load around the forecast. Additional documentation is available in the Technical Bulletin available at http://www.caiso.com/2b30/2b307b2a64380.pdf.

The Flexible Ramping Constraint does not offset or reduce the required procurement of regulation or contingency reserves and is not reflected in the energy price unless imbalance condition change such that in RTD the resource resolving the constraint is dispatched above minimum load. Since energy prices during RTPD and HASP are advisory for internal resources, the commitment of capacity in these real-time market processes does not directly impact real-time energy price. Incremental ancillary services are procured in RTPD and these prices are binding. In assessing the pricing impact of this constraint it is necessary to separate based upon the ramping direction. In instances where the Flexible Ramping Up Constraint is binding, an additional resource (presumably higher commitment plus bid cost) is committed at PMin and the resource which would have been committed and loaded up to its PMax absent the constraint is committed at a lower level so that the resource may be able to provide additional upward dispatch capability. The resources committed via the constraint are eligible to set prices in real-time if needed. The resources will be able to receive additional market revenue if the imbalance energy requirements increase above forecasted levels such that the need for ramping requirements are realized. Both resources are eligible for bid cost recovery to address any shortfalls from being committed. This is analogous to procuring additional non-contingent spinning reserves; however, the reserved capacity is used to meet real-time upward dispatch requirements and not to satisfy WECC contingency reserve procurement targets. If additional spinning reserves would have been procured in the day-ahead market (above WECC procurement targets) the additional capacity would have caused the spinning reserve Ancillary Service Marginal Price (ASMP) either to remain the same or increase and the reserve demand would be increased to reflect the reserved capacity. Due to the co-optimization of energy and ancillary services, there may be interplay with the SMEC related to the increased reserve demand. In the real-time market the capacity reservation of the binding constraint is difficult to reflect in future non-binding five minute energy prices. To the extent in RTPD a resource is not awarded another reserve such as spinning reserve to allow the resource to be available to meet the forecasted ramping requirements, there may be an opportunity cost for such a resource. On the other if the ramping requirement is being provided by resource capacity that is otherwise not economic for energy or other reserves, the opportunity cost would be zero. Therefore it may be appropriate to consider a compensation method to recognize at least the opportunity affects of the additional ramping constraint. The appropriate pricing mechanism for this constraint will be assessed based upon how regularly the constraint is binding and the extent to which the constraint results in lost opportunity for resources. As an interim step, ISO proposes to share information including the quantity of the requirements and the associated shadow price of the binding to assess the appropriate compensation method.

2.4 Allocation of Integration Costs

The integration of substantial amounts of VER capacity into the supply fleet poses several challenges that will tend to increase the costs of meeting load and reserve requirements and maintaining reliable operation. These increased operational costs will result from a combination of increased reserve procurement, greater operational demands on conventional resources, increased need for resources that can offer specific performance capabilities, potential for increased uplift amounts, and the expected need to provide some form of capacity payments to conventional resources to supplement the reduction of spot market revenues as spot prices decline due to the lower marginal costs of VER. A central question for this initiative, and the topic of this section, is whether these integration costs should be allocated directly to the VER that may be viewed as causing the increased costs, and if so, what cost allocation principles should apply and what methodologies should be used to determine each resource's appropriate cost share. An overarching question to keep in mind throughout this topic is how the market rules – particularly with regard to allocation of integration costs – can be used to provide long-term incentives for developers of VER to design new renewable resources that are better able to manage their own variability and reduce such impacts on grid operation.

In pursuing this initiative the following are some of the questions that need to be addressed.

1. Which specific integration costs should be allocated to VER?
2. How should the relative cost shares charged to demand versus charged directly to VER be determined? For example, if VER should be charged for a portion of the cost of ancillary services, what methodology would be appropriate and fair for measuring the incremental impact of VER on this cost?
3. Should cost allocation be based simply on resource categories (e.g., technology, PMax), or should it be based on measured performance of each resource during the hours the costs are incurred?
4. If measured performance is the basis for cost allocation, should these costs then be allocated to all resources, regardless of resource type, that exhibit the same performance to a lesser degree?
5. Should allocation of integration costs be limited to the operational and spot market areas, or should we also consider allocating some of the integration costs through the generation interconnection procedures (GIP)?

The list above is not intended to be exhaustive; stakeholders are encouraged to help refine the key questions, identify others that have been omitted from this list, and suggest guiding principles that will be helpful in this effort.

2.4.1 Integration costs for VER Imports

Under new dynamic transfer provisions the ISO is now completing for submission to FERC within the next few months, VER outside the ISO will be able export their variability from their host BAA into the ISO using either a dynamic scheduling or a pseudo-tie arrangement. The current dynamic transfer initiative did not address the question of allocation of integration costs associated with these VER imports, however, but deferred that question to the present initiative. The ISO expects that the questions and issues identified in section 2.3.1 above will be relevant for dynamic VER imports as well as for internal VER. The ISO requests input from stakeholders as to whether there are specific factors or attributes associated with dynamic VER imports that make them different to internal VER and require different treatment or special consideration with regard to allocation of integration costs.

2.5 Modifications to Intra-Day Market Settlements

2.5.1 Full Hour Ahead Market

A possible market design enhancement being considered to better accommodate the scheduling of intermittent generation resources is the introduction of hourly intra-day markets, cleared and settled for each hour against day-ahead schedules, with actual real-time load and generation settled against these intra-day hourly schedules. This design differs from the current HASP, which schedules imports and exports against the load forecast and commits quick start resources, in that the intra-day market would determine hourly prices and schedules against which all real-time load and generation deviations would settle.

Creating such a market with full settlements would essentially change the ISO market structure from a two-settlement to a three-settlement market. Clearing and settling such a market implies the participation of both buyers and sellers; thus unlike today's HASP a full hour-ahead market would be designed to accept bids from internal load rather than simply clear supply offers against a load forecast. An important design feature for such intra-day markets is to specify the identity of the buyers and sellers in these markets, i.e., whether there should be any limitations on participation, which will impact the nature of the potential benefits from implementing these markets. For example, would the design accommodate all three possible convergence bidding combinations: day-ahead to hour-ahead, hour-ahead to real-time, and day-ahead to real-time?

Before we go too far in trying to specify potential design alternatives for an hour-ahead full settlement market, it is important to identify the potential benefits that could be achieved through such a market, particularly with regard to renewable integration which is overarching purpose of this entire initiative. As we have discussed with stakeholders in Phase 1 of this initiative in the context of revising the PIRP, the ISO does recognize that many VER would like an opportunity to establish a schedule as the basis for measuring real-time deviations that can be specified as close as possible to the real-time operating hour. It is not clear, however, whether an hour-ahead settlement market would be an effective vehicle for this – i.e., it would probably have to utilize the same time frame as today's HASP, with bids submitted by T-75 and market results posted by about T-60. Moreover, it's also not clear that instituting a full-blown third settlement in the market structure is necessary to accomplish the limited objective of providing a scheduling opportunity for VER. Thus, at this point in the present initiative, the ISO does not see how the cost and complexity of designing and implementing a full three-settlement market structure could be justified in terms of the benefits it would provide. The ISO requests that stakeholders focus on this question in their comments. Specifically, if you are inclined to favor the creation of a full hour-ahead settlement market, please provide your justification in terms of the needs it would address and the benefits it would provide.

2.5.2 15 minute Market in Real-Time

Another option the ISO could consider in lieu of a full hour-ahead market to accommodate the scheduling of intermittent resources in the markets would be to implement a 15-minute market in real-time. This approach could allow bids to be submitted every 15 minutes for all resources types and allow supply to clear against demand. This approach would require coordination between the ISO and other balancing authorities to facilitate changing transmission reservation rules outside of the CAISO footprint. This approach could provide the following benefits:

- Increased bidding opportunities for all resources closer to real-time
- Retains two-settlement system
- Eliminates need for HASP market and problems with divergence between HASP and Real-Time prices

2.5.3 Uneconomic Adjustment Priority for VERs

When the market optimization exhausts the supply of decremental energy bids and still needs to reduce supply to manage grid congestion or system over-generation, it resorts to the uneconomic adjustment procedures whereby self-schedules of supply resources are decremented based on administratively specified parameter values known as penalty prices. These penalty prices are set at values well outside the range of allowable economic bid prices so that the market optimization will exhaust the supply of effective economic bids before reducing self-schedules. The tariff specifies a system of priorities for different types of self-schedules, such that when the market performs uneconomic adjustment it will adjust the lower-priority self-schedules first (i.e., generic self-schedules) and the higher-priority self-schedules last (i.e., reliability must-run units and schedules utilizing transmission ownership rights and existing transmission contracts).

Some stakeholders have suggested that the generic self-schedule classification – the lowest priority level in this system – be subdivided by the addition of a new priority level for renewable resources, so that when a renewable resource and a conventional resource are both operating at their self-scheduled levels and are equally effective in mitigating the congestion or over-generation problem the conventional resource will be decremented first. Today, absent such a priority distinction, the two resources would receive pro rata decremental instructions proportional to their self-scheduled amounts. At this time the ISO does not have a position on the merits of this idea, but only offers it for stakeholder discussion.

The following are some things to consider in evaluating this idea:

First, the priority distinction could be defined in other ways than renewable versus conventional. Another suggestion is to distinguish between resources with full capacity deliverability status (higher priority) and energy-only status (lower priority).

Second, as the ISO discussed in great detail with stakeholders prior to launch of the MRTU market redesign, adding more levels of priorities and their associated penalty prices makes the optimization more complex and increases potential inconsistencies between the schedules determined in the scheduling run and the prices determined in the pricing run.

Third and perhaps most important, although there will always be some instances where uneconomic adjustment is necessary, the market optimization yields the most efficient results when it clears based on economic bids. The ISO therefore continues to strive for market improvements that increase the incentives for resources to submit economic bids rather than self-schedules, so that the market will rarely exhaust economic bids and need to resort to uneconomic adjustment. One key improvement in this regard is the reduction in the energy bid floor, a design element now being finalized in Phase 1 of the Renewable Integration initiative. With a lower bid floor, resources for which reduced output carries significant opportunity cost will be able to offer decremental bids at prices that adequately compensate them for such costs. As a general matter the ISO strongly prefers solutions that result in more economic bids and fewer self-schedules, because that is how the market as a whole receives the greatest benefits from the economic dispatch and unit commitment algorithms used in the market software.

2.6 Longer term procurement issues

2.6.1 Capacity Market

In 2007 the CPUC and the ISO initiated parallel stakeholder initiatives to evaluate the merits of creating a multi-year forward central capacity market (CCM) as a vehicle for suppliers – including developers of new supply capacity – to offer, and load-serving entities to procure Resource Adequacy (RA) capacity. Ultimately the CPUC decided not to modify the current RA program structure, which requires load-serving entities to demonstrate their procurement of RA capacity only one year at a time, prior to the start of each calendar year, and to perform such procurement through bilateral contracting rather than through a bid-based market. One of the challenges to a CCM that was discussed at the time was how to incorporate needs for different performance characteristics – such as fast ramping and the ability to provide regulation services – into the definition of the capacity product that would be cleared in such a market. Many of the parties engaged in these initiatives observed that a CCM would be most liquid and hence most competitive if the product being transacted were more generic, whereas the expected expansion of VER in the supply fleet meant that there would be a much greater need for “non-generic” capacity that had the performance characteristics needed to help integrate VER into grid operation by responding quickly to compensate for their variability.

Against this backdrop, and with greater understanding of the challenges of renewable integration that we had during those initiatives, the ISO asks stakeholders to consider and to comment on whether some form of CCM would be a beneficial component of the market enhancements now being examined. The need for non-generic capacity types is still a central issue, so if there is merit to a CCM, a key question to address would be how to define the capacity product to be transacted in a CCM, and how to structure the CCM itself so as to elicit robust competition and result in efficient development of the needed types of new resources, in the right quantities and the right locations.

2.6.2 Forward Reserve Market

Closely related to the discussion of the previous section, an alternative (or possibly a complement) to a CCM could be a forward reserve market (FRM). Instead of focusing on RA capacity as a CCM would, an FRM would focus on forward procurement of defined reserve services – operating reserves, regulation, and other new services as may be defined in this initiative. Today, reserves are procured by the ISO at most a day ahead in the ancillary services (AS) markets. As such a generation developer considering building a plant that is capable of providing ancillary services would expect to rely on earnings from the spot AS markets for the additional revenue to compensate for the cost of investing in such capacity. A key question to ask is whether the current spot AS markets offer sufficient revenues to elicit investment in the needed capacity types, or whether another mechanism might be needed. If another mechanism is warranted, would it be best to promote such investment through a CCM for RA capacity, as raised in the previous section? Or should the ISO design a more forward and longer-term procurement market for AS? In order to start this discussion, the ISO has provided a description of ISO New England's FRM later in this document, as a case study from which we might gain insights into the benefits and limitations of an FRM.

3 Comparison with other ISO/RTOs

The concept of paying regulating resources based on the amount of regulation they provide, the amount of movement or mileage, has been embraced by FERC in its Regulation NOPR (RM11-7-000, February 17, 2011) and may be a viable strategy to aid the ISO with the integration of renewable resources. Therefore, for educational purposes, this section describes pay for performance Regulation payments that have been implemented or are in progress of being implemented at other ISOs. This section also describes the forward reserve market at ISO New England as they are the only ISO with a forward reserve market

3.1 Pay for performance Regulation at NYISO, PJM and NEISO

3.1.1 New York ISO – Regulation Performance Factor

The New York ISO's payments to regulation providers include a regulation performance factor which provides higher payments to resources that better follow their regulation signal. The essence of the performance incentive is that the NYISO tracks the output of each regulation resource over each 30 second interval and compares its output to its highest and lowest six second base point over that 30 second interval. The generator is treated as over generating (positive control error) if its output exceeds its highest base point over that 30 second interval and under generating (negative control error) if its output is less than its lowest base point over that 30 second interval.

The greater the amount of under or over generation by a regulation resource measured in this way, the greater the reduction in its payment for regulation.

The New York ISO's regulation performance factor is described in Attachment C of the Ancillary Services Manual. The performance index for a generator in an interval is calculated as the percent deviation from the regulation margin (based on deviations for over/under generation, and where 100% means no deviation from the margin) , multiplied by the percentage of seconds in the interval in which the unit is supplying regulation, plus 10%. Mathematically, the performance index for an interval is:

PI = [(URM - PCE - NCE)/URM]*(RegPeriod/S) +.1

Where:

URM = unit regulation margin for the dispatch interval (this is generally the unit ramp rate times 5 minutes but could be different if the dispatch interval was not five minutes long or the resource was capacity constrained in the amount of regulation it provided).

PCE = regulation provider's overgeneration (Positive Control Error) summed over the interval;

NCE = regulation provider's undergeneration (Negative Control Error) summed over the interval;

RegPeriod = # of seconds during the interval that the resource is supplying regulation

S = # of seconds in the interval

The final .1 term in the PI equation in effect provides a dead band so that resources with less than 10% control error are paid the full regulation price as explained further below.

The performance index is potentially subject to adjustment by a payment scaling factor (PSF) before being used in calculating the total settlement. The New York ISO Tariff and Ancillary Service Manual provide that the payment scaling factor will be set between 0 and whatever higher value is required to incent the level of regulation performance required to meet NERC, NPCC or other standards.

The payment scaling factor was set initially at zero, with the tariff allowing for increases as needed to improve regulation performance. We have not been able to find any publicly available indication that the payment scaling factor value has ever been increased above 1.

The regulation payment factor (K) that is used in calculating regulation payments is defined as:

K = (PI - PSF) / (1 - PSF), but is capped at 1.

K is the proportion of a resource's scheduled real-time regulation for which it will be paid. Hence for PSF = 0, K = PI, and K would equal .9 for a resource with a performance index of .9. If the PSF were set at .5, K would equal 2PI –1, and K would equal .8 for a resource with a performance index of .9. With K = .9, a resource would be paid for 90% of the regulation it was scheduled to provide. While PI could take values as high as 1.1, K is capped at 1 so no resource can be paid more than the full regulation price.

Under the ISO New England regulation market design in place since October 1, 2005, the regulation clearing price is based on generator offers and is paid in addition to payments for energy market opportunity costs.[11] The clearing price is paid to each generator for the regulation capacity scheduled and is also paid for the amount of regulation called upon, i.e. mileage. The payments for mileage are deflated, however by the ratio of total capacity to total mileage.

Hence:

Total payments to capacity = total capacity * Clearing price

Total payments for mileage = total mileage * (total capacity/total mileage) * clearing price.[12]

The two payments are therefore roughly equal in total for all generators, but generators that are called upon to provide more regulation get more of the service payments.

In addition, the ISO New England AGC algorithm assigns more movement to regulating resources that move fastest. So fast moving regulating resources are called upon to provide

---

11 The pricing system is described, rather tersely, in the ISO New England Transmission, Markets and Services Tariff section III.3.2.2, particularly subsections (c), (f) and (h).

12 If for some reason the clearing price is lower than the resources regulation offer price, the payment is based on the resource's regulation offer price.

more regulation and will get a disproportionate portion of the regulation mileage payments. Low cost (infra-marginal) fast moving regulating resources will make a lot more money per megawatt of regulation capacity providing regulation than a slow moving high cost resource.

The mileage payment is viewed by ISO New England as compensating regulating resources for wear and tear and also as providing an incentive to "ensure resources' willingness to move."[13] Since mileage for a unit is based on the amount it is instructed to move,[14] rather than the amount it actually moves, it does not provide any incentive for regulating resources to respond to their AGC instructions. Moreover, because the mileage payment is adjusted based on the capacity to total mileage in the hour, a generator could get paid very little per megawatt for moving in an hour in which a lot of movement is needed and could get paid a lot per megawatt in an hour in which very little movement is needed. To the extent that these effects are predictable time of day effects they could be reflected in offer prices for the hour.[15]

It is not clear why resources providing regulation are paid both a capacity payment based on the offer prices used to determine the mileage payment and an opportunity cost. The dual payment for capacity and opportunity costs seems to lead to a rather complex process being used to schedule capacity based on the sum of the clearing price of capacity and the opportunity cost.

The design of the ISO New England mileage payment has several elements that could be problematic that the CAISO should take into consideration if we decide to implement a similar payment:

- Separate capacity payments based on the offer price used to calculate the mileage payment and based on short-term opportunity costs in the energy market;
- Payment based on instructed movement rather than actual movement;
- Scaling down of payment for movement based on the amount of movement called for during the period.

3.2 PJM Pay-For Performance Regulation

Currently PJM compensates all resources that provide Regulation uniformly. There is no differentiation for resources that can respond to a Regulation signal more quickly or accurately. Similarly to the California ISO, compensation for Regulation is targeted to offset energy opportunity costs and not to incent performance.

From PJM's perspective their currently methodology to compensate resources providing Regulation is problematic because it 1) Does not provide incentive for resources to perform at a level any higher than the minimum required; and 2) Limits the ability to use multiple Regulation

---

13 See ISO New England June 16,2010 filing in Docket AD10-11-000 p. 7.

14 See the ISO New England Market Operations manual M-11, p. 77 section 3.2.8 "Regulation Service Megawatts in an hour are calculated as the sum of the absolute value of positive and negative movement requested by the ISO while providing Regulation within the hour. The computation of Regulation Service Megawatts assumes that generators providing Regulation will track their AGC Setpoint signals at their claimed Automatic Response Rate without delay or overshoot. This tracking computation is known as Perfect AGC Response (PERFAGC). The Regulation Service Megawatts are computed as the sum of absolute values of the differences in PERFAGC between successive four second samples during an hour while providing Regulation."

15 This is possible in principle but is not possible in the actual ISO New England implementation because the regulation offer prices are required to be the same over the course of the day.

signals (one for fast resources and one for slow) as compensation does not recognize the unique capabilities of each resource.

PJM is proposing to implement a Regulation Market Incentive Payment to address these issues. Their proposed incentive payment will be based on the following:

1) Accuracy resource follows regulation signal during the hour
2) Quantity the resources moved during the hour
3) Highest cleared Regulation offer price during the operating hour

The incentive payment would be in addition to current Regulation market payments.

For educational purposes, a representative from PJM will present an overview of this proposal to market participants at the April 12 stakeholder meeting and provide the opportunity for comments and questions from the audience.

3.3 Forward Capacity Markets

Currently, PJM, ISO New England and NYISO all conduct forward capacity markets. The ISO performed some benchmarking studies on the PJM and ISONE capacity market designs during the 2007 stakeholder initiative on capacity markets. Those summaries are posted on the ISO website at: http://www.caiso.com/1b7f/1b7fd6ebe740.html . None of the ISOs include non-generic capacity attributes in their forward capacity markets.

3.4 Forward Reserve Markets

ISO New England's forward reserve markets have the following features:

- Advance procurement of expected requirements for 10 minute (non-spin) and 30-minute reserves
- Winter and summer forward procurement periods
- Cascaded procurement and pricing[16]
- No must offer requirement

The ISO New England forward reserve market is intended to cover the portion of the ISO New England 10 minute and 30 minute reserve requirements that is not met by 10-minute spinning reserves.

As initially implemented, capacity contracted to provide reserves in the ISO New England forward reserve markets was required to be offered into the energy market at or above a forward reserve threshold price to ensure that the capacity would not be scheduled to provide energy during normal market conditions.[17] If the reserves were provided by on-line capacity, the resource providing the reserves was obligated to self-schedule to operate at minimum load in the day-ahead market. This requirement both ensured that the resource would be on-line and able to provide reserves and that no uplift costs would be incurred in addition to the forward

[16] Excess 10 minute reserves can be used to meet the thirty minute requirement, so the price of 30 minute reserves is less than or equal to the price of 10 minute reserves.

[17] The threshold price varied monthly with fuel price indexes.

reserve payment in order to obtain the reserves. Finally, the resource was only paid for the forward reserves if it scheduled capacity to provide reserves both day-ahead and in real-time.

Initially, suppliers that sold forward reserves but failed to offer/schedule that capacity day-ahead not only lost the hourly reserve payments, they also paid a penalty equal to the difference between the day-ahead energy price and the forward reserve price. Since the day-ahead energy price will almost always be higher than the forward reserve price, this penalty provided a strong incentive to supply contracted reserves and a strong incentive to supply reserves from the contracted capacity, even if the reserves could be supplied at lower cost by other units.

Due to the combination of settling imbalances at an artificially high price and the fact whether a particular unit is economic to provide on-line reserves varies depends on the energy price, the design of the ISO New England forward reserve market made it artificially expensive for market participants to use the capacity of non-quick start units to supply reserves in the ISO New England forward reserve market. The prices of 10 and 30 minute reserves in the ISO New England forward reserve markets have been very high relative to prices for the same categories of reserves in New York, consistent with the expected effect of such restrictions on competition.

The motivation for the establishment of the ISO New England forward reserve market appears to have been a desire to stimulate the construction of more quick-start capacity in New England, which historically had relatively little quick start capacity. The artificially high penalty for not providing reserves from a contracted resource favored the supply of reserve from off-line quick start capacity, relative to on-line units, because the economics of supplying reserves from a particular quick start resource generally does not vary with the price of energy, while the cost of supplying reserves from a given on-line resource depends on the resource’s opportunity cost in the energy market, which will vary from day to day and over the course of the day such that the same on-line resource will typically not be an economic source of reserves in every hour of the day or every day of the year. While these artificial restrictions and penalties probably raised the profitability of quick start capacity, they also greatly increased the reserve costs borne by energy consumers and likely reduced the efficiency of the unit commitment and dispatch.

In October 2006, ISO New England added location requirements to its forward reserve markets. These requirements are calculated prior to each auction and ensure that the capacity purchased in the forward reserve market is located where it is needed to meet reliability requirements, particularly New England’s 2nd contingency reserve requirements for the Boston area and Connecticut. If there is not enough capacity to meet the locational requirement, the clearing price for the region is set equal to the forward reserve price cap. This has happened a number of times, particularly for Connecticut as can be seen in Table 1, where a price equal to $19.4 per megawatt indicates that the price was at the cap.

Several other design changes were introduced in October 2006 to address some of the more glaring inefficiencies of the original design. First, reserve suppliers are now allowed to provide reserves from a portfolio of units. This ability to provide reserves from a mix of units reduces the cost for multi-plant owners to offer forward reserves from non-quick start capacity, but the rules still limit competition from the non-quick start capacity of smaller suppliers who do not operate a sufficiently large or diverse portfolio of resources to take advantage of this flexibility. Second, rules were introduced allowing bilateral sales of capacity to provide reserves. Third, the penalty for failure to supply reserves in the day-ahead market was reduced to 50% of the forward reserve price (i.e. the supplier foregoes payment in the hour and is charged an additional penalty equal to 50% of the forward price). Given this background regarding the ISO New England’s forward reserve market, t is not clear how such a program would contribute to cost effective integration of intermittent resources in California. The New England design discriminates against flexible, fast ramping on-line resources in favor of off-line resources, even if the off-line resources are fixed block units with no dispatchable range. If the California ISO found it desirable to enter into forward contracts for rampable reserves, to encourage the construction of such capacity, it would be better to define those contracts as purely financial contracts that would settle against the day-ahead reserve price.

This raises the question of in what circumstances it makes sense to contract forward for reserves. One reason to contract forward for reserves could be that the reserves market is non-competitive, and by contracting forward, reserve prices would be constrained by the costs of potential entrants, reducing reserve prices. This does not appear to be is a concern in the ISO markets at present.

Another reason for forward contracting might be for load serving entities to reduce the uncertainty of future reserve costs, i.e. to hedge their reserve costs. Since reserve costs are a much smaller portion of the cost of meeting load than energy, it is not clear why it would be particularly important to enter into such hedges. Moreover, it would normally be the load serving entities that would make the evaluation of whether they wanted to enter into such hedges, and there is no barrier to them contracting forward for reserves with either existing generators or potential entrants if they wished to enter into such forward hedges.

A third reason might be that uncertainties regarding future market design changes were perceived to be deterring the entry of generation capable of providing reserves, giving rise to the potential for inefficiently high reserve prices at some point in the future when reserve requirements rose or other resources exited the market. This could be a valid reason for entering into forward contracts, but it is not clear it is applicable to California.

With regard to the second and third potential rationales, it needs to be kept in mind that if the market design for the forward reserve market creates additional risks for suppliers that contract forward to provide reserves (as is the case for on-line suppliers in New England), forward reserve prices may be higher, rather than lower than spot reserve prices, and a given level of forward reserve prices may provide less incentive for the entry of new supply than would the same level of spot prices.

4 Proposed Plan for Stakeholder Engagement

Publish Discussion Paper	April 5, 2011
Stakeholder Meeting	April 12, 2011
Stakeholder Comments Due	April 29,2011
Publish Issue Paper and Draft Roadmap	Late June 2011
Stakeholder Comments Due	July 2011

4.1 Next Steps

The ISO will hold a stakeholder meeting on April 12, 2011 for Phase II. Stakeholder comments are requested by April 29, 2011. The ISO welcomes all comments but seeks stakeholder input specifically to address the following topics and questions:

- The proposed plan for Phase 2 as outlined in the Introduction, including the idea of a comprehensive market roadmap and a subset of topics to address this year.
- Is the list of topics and issues for consideration in Phase 2 and inclusion in the roadmap complete? If not, please identify others that should be included.
- Which topics and issues should be high priority for addressing this year?

Phase I of this initiative is scheduled to go to the Board in June 2011. The ISO will post a revised Straw Proposal for Phase I on April 19.