Stakeholder Comments

Renewable Integration: Market and Product Review Phase 2 Discussion and Scoping Paper

Submitted by	Company	Date Submitted
Jeffrey Nelson (626)302-4834	Southern California Edison (SCE)	4/29/2011

SCE thanks the California Independent System Operator (CAISO) for the opportunity to comment on the scoping paper and discussions during the April 12 meeting. The CAISO's understanding of the complexity of this issue and emphasis on a comprehensive solution is encouraging. SCE commends the CAISO on its initiative and vision in this process.

SCE strongly supports the CAISO in its approach and realization that stakeholders will need the devotion of substantial resources and time in order to develop an efficient, reliable, and least-cost market structure. SCE will work with the CAISO in further development of each significant aspect of VER (Variable Energy Resource) integration.

The comments in this document are presented with a focus on the comprehensiveness and interdependency of issues regarding renewable integration. SCE does not propose a comprehensive redesign of the existing market framework, rather, SCE identifies components of the market which require scrutiny, and may benefit from enhancements as part of an end-state solution.

I. Market Design Principles

The CAISO requested principles for moving the market design process. Given the complexity of market changes, we offer the following principles to help guide discussions and evaluate proposals. The CAISO should consider these principles and better clarify the principles that will guide its decisions moving forward.

1. <u>The optimization should find least-cost solutions.</u> The market objective function should minimize total cost. In doing so, the objective function should use probabilistic approaches that sufficiently consider the uncertainty of many market components. This implies that the CAISO should move away from the deterministic approaches currently used.[1] Moving forward, point estimate

[1] Under this approach, we should not assume that the market will produce more volatile prices simply because the optimization has to deal with greater uncertainty. Moreover, any assertion that a more volatile market has a lower cost compared to non-volatile alternatives has not been demonstrated. To the contrary, based on observations of erratic, and sometimes extreme and often discontinuous prices in the current real-time market, it appears likely that

solutions of perfect load forecasts and perfect generator-by-generator output are simply not reasonable assumptions in light of the new mix of resources, including demand response[2]. Applying a deterministic approach to a stochastic process is a flawed approach.

2. <u>Determine the needs.</u> Market products should appropriately target the issues that certain market functions are trying to solve. For example, Regulation is a good product for quick-response, short-term needs. In contrast, using a 4-second dispatch-interval product for a half-hour variation is an inefficient use of resources that could potentially make appropriate resources unavailable at later time frames. Such a relatively longer-term variation should be resolved using a product appropriate for the applicable time horizon and ramp rate requirements.

   Additionally, when procuring resources for a specific benefit, the CAISO should not presume other independent benefits that may be incorporated in the nature of the resource they acquire. Where practicable, each resource's characteristics should also be decomposed based on its benefits just as its characteristics should be decomposed based on costs. Such granularity will facilitate the CAISO's ability to identify the right products for its needs.

   For example, certain Regulation resources also provide system inertia. However, procurement of such resources should not be based on considering all their characteristics as a whole. Instead, procurement decisions should be taken based on independent, individual characteristics (rank each independent individual characteristic with a score, compare each candidate's scores across characteristics, then make a decision). Following this, the resources chosen for implementation should then be compensated based on performance regarding each independent characteristic. This is not to say that a product with several CAISO-sought-after features would not be in an advantageous position of being chosen. On the contrary, systematically measuring each independent characteristic would lead to easier identification of each characteristic of a resource. This leads to the next point of paying a resource for each characteristic feature it offers to fulfill the needs of the CAISO.

   The principle of determining need is key to procurement of the right set of "tools" to do the job:

   i. <u>Conceptually, the CAISO should procure what is required after the requirements are known</u>. There is a tradeoff between buying a product (i.e. A/S) well prior to delivery when uncertainty regarding needs is high but options to solve the need are plentiful, as opposed to buying closer to real-

---

the current approach, which in effect ignores uncertainty, is not producing a least-cost solution (in direct opposition to its stated objective). Rather, a market that functions on point estimates and produces high price volatility is likely more costly than a market that optimizes expected costs in consideration of variability and uncertainty and instead produces more stable pricing. The latter also likely produces a more reliable solution.

[2] It is not the right approach with steady generation and it is even more inappropriate given an increasing portfolio mix of intermittent generation.

time when there is less uncertainty, but the options to address the uncertainty are fewer. The tradeoff also involves costs. Locking-in early forecasts can lead to high costs due to overprocurement, however, procuring later can also lead to high costs due to more limited supply alternatives. There is a need to address the DA versus RT procurement approach and a need for consistency in methodology. This approach should consider uncertainty, the number of alternatives, and costs. The timing of when integrating services are procured (i.e. DA, RT, or possibly another window between the two) should be part of the design discussion.

3. Cost causation. Misallocating costs for any reason will cause inefficiency and incorrect market signals. In turn, the CAISO should expect misallocations to cause markets to diverge from low-cost, efficient, and reliable solutions[3]. SCE supports cost causation and cost allocation principles in the market design. Some areas relevant to correct cost-allocation resulting in appropriate market signals are:
    i. Spot markets should provide correct marginal operating signals. Correct marginal operating signals lead to appropriate RT operating behavior and improved RT reliability in the short run. In the long run, these signals support efficient investment in appropriate resources and technologies that allow better integration in the CAISO market with lower costs of procurement.

       Investments in technologies that provide least-cost means to integrate intermittent resources should both reduce system-wide integration costs and help foster greater certainty over expectations of integration costs. These value-added technologies will lead to increased long term returns for both the differentiated resource as well as the market. Investment in integration technologies should be encouraged through correct pricing as such investment will in turn lead to more efficient market results.

    ii. Send accurate price signals regarding return on marginal investment in the medium to long-term. These signals would be necessary to lead to more efficient use, capital additions, and operation of resources. For example: Assume Solar Resource A has an extremely high ramp rate in the morning as the sun rises. This in turn forces the CAISO to procure additional ramping capability at a significant cost. In a properly designed market, the CAISO then allocates these costs back to Resource A. If Resource A now makes investments (either a capital investment or a service procurement) that reduce the rate of its initial morning ramp, the CAISO can reduce its

[3] In the April 12 meeting, some stakeholders argued against correct cost-allocation, claiming it would result in increased financing costs or increased price of generated electricity. Arguing against correctly measuring any economic variable is essentially arguing against the basic tenets of economic markets. Further, concerns about impacts to financing are misapplied because financing is required for investments regardless of resource type. Clearer cost-causation rules could improve financing for market participants by reducing a current or potential source of uncertainty.

associated ancillary services (A/S) procurement, the resource in turn reduces the cost allocated to it by the CAISO, and this cycle continues until an efficient equilibrium is reached.[4] Frequency regulation compensation proposed by the Federal Energy Regulatory Commission (FERC) is an extension of this approach. A resource that provides a superior product[5] should be compensated for providing that product.

iii. The market should produce correct long-term investment signals. With rational and efficient price formation and correct cost-allocation, the market will encourage appropriate long-term investment in lower-cost, reliable technologies[6]. Such investment may include "controls" on existing facilities, and should help direct the "resource mix" as investors decide which form of technology (i.e. wind, solar PV, solar thermal, etc.) to add to the grid.

iv. While ultimately "load pays", an efficient design will result in lower ***total costs*** compared to inefficient design alternatives. Ultimately, load pays for everything, since it is load that is being served. However, how much should load pay? There is no intention from SCE (nor should there be for any market participant) to avoid paying its fair share of costs[7]. However, load should be allocated what is appropriate given its behavioral characteristics and market performance. Each market participant should be assigned costs appropriate to their behavioral characteristics, market performance, and costs imposed on the grid.[8]

4. Target payments to only those resources providing needed services. The design should compensate resources that meet the CAISO's needs, not resources failing to provide these needs. Just as costs should be allocated to their sources, payments should be targeted to those providing the services. Rather than socializing payments to all, the CAISO needs to ensure that those providing a service – and only those providing the service - are properly compensated in a

---

[4] This leads back to the "Compensating resources that meet the CAISO's needs, not resources failing to provide these needs." principle. Payments and costs should not be socialized.

[5] In this context, "superior" is defined as a product that meets the CAISO's operational needs while having a lower integration cost relative to a product that meets the same operational needs at a higher integration cost.

[6] At the April 12th stakeholder meeting, some parties argued that correct cost-allocation would discourage long-term investment. First, this argument demonstrates a lack of commitment to low-cost, reliable product provision based on market considerations. Marginal investment in technologies that lead to low cost, reliable resources would naturally incentivize long-term investment in intermittent resources as well. Second, if correct cost allocation actually discouraged long-term investments, controllable generation (which have input factor costs as well as a lack of subsidies and rebates) would have exited the market a long time ago.

[7] SCE disagrees with comments that proper cost allocation will directly or indirectly lead to barriers to competition. We envision that the same allocation rules, once implemented, will apply in a non-discriminatory fashion, regardless of type of market participant. We expect uniform rules irrespective of who owns the generation (i.e. merchants, IOUs, municipalities).

[8] This leads back to the cost causation argument which was brought up by several stakeholders (City of Pasadena, Bay Area Municipal Transmission Group, etc.) who questioned why some intermittent resources were unwilling to pay for costs caused by their performance in the market.

targeted manner. Doing so will encourage participants to find ways to provide additional valuable services to the CAISO, while also appropriately limiting market costs.

i. Avoid cross-subsidies. For example, if there is an intermittent resource exporting from the CAISO control area, they are burdening the system as the CAISO "firms and shapes" the power. The exporter should pay these costs, and the costs should not be shifted other market participant. A proper market design must address and discourage cost-shifting.

II. Scope of Process

SCE understands the CAISO's objective of this process is to design a "comprehensive roadmap by December 2011" that includes a vision for the market end-state, and plans for staged development and implementation.

While we support this objective, we feel the project will benefit by better defining what is "in scope" and what is "out of scope". To accomplish the above goals, SCE recommends CAISO to consider the following market components "in scope" for discussion:

1. The Real-Time (RT) market. Scope should include changes in optimization formulation to deal with uncertainty and variability while seeking a least-cost solution, constraints and/or products to ensure the CAISO has sufficient intra-hour operating flexibility, the timing of settlements (i.e. 10-minutes vs. 15-minutes), integration of demand response, treatment of dynamic schedules, sub-hourly schedule changes, changes to Regulation[9] and the regulation dispatch algorithm, alignment of ancillary services/energy/possible new products/scarcity pricing, cost-allocation of energy, products and uplifts.

2. HASP market. Changes in time-lines to better integrate the CAISO with other western markets, potential elimination of the HASP settlement, consideration of sub-hourly schedules, cost-allocation of energy, products and uplifts.

3. STUC/RTUC. Changes in constraints to ensure commitment of sufficient operating flexibility, integration of VER forecasts, integration of demand response, and possible incorporation of updated and binding forecasts from VER resources prior to the delivery hour.

4. RUC. Constraints necessary to ensure capacity for operating flexibility as well as capacity for energy needs, RUC pricing, simultaneous RUC/IFM optimization, cost allocation of RUC capacity and uplifts.

5. Day-ahead (DA) market. Additional constraints/products to ensure sufficient operating flexibility in RT, objective function changes to ensure cost minimization in light of

[9] SCE is preparing comments in response to the FERC Frequency Regulation Response NOPR (RM11-7) and anticipates the CAISO will have detailed views, as well as a stakeholder process, on this matter soon, given the urgency of the issue.

increased variability and uncertainty of generation output, integration of demand response, cost allocation of energy, products and uplifts.

6. Resource Adequacy (RA) Process. Ensuring, on a planning basis, the supply fleet satisfies system and local reliability, consideration of additional requirements to ensure operating flexibility on a planning basis, and if so, a CAISO structure to assign RA operating flexibility obligations to generation contributing to the flexibility need.

7. Resource Sufficiency. CAISO process to ensure needed generation (for energy, capacity or operating flexibility) does not retire prematurely, and CAISO process to ensure construction of new generation needed for VER integration.

III. General Market Design Objectives and Constraints

Below we offer design objectives and constraints that should help frame discussions and provide a tool to evaluate whether a proposal meets the ultimate design goals. We encourage the CAISO to specify their perceived set of objectives and constraints.

1. The design should result in a durable, end-state for the market that deals effectively with **at least** 33% RPS (Renewable Portfolio Standard).

   A market solution must be robust enough to accommodate not just:
   (a) The SBX1-2 requirement of 33% RPS; but also
   (b) Significant additional penetration of renewables and intermittent distributed generation.[10]

   Given the State's legal mandates, as well as further calls for additional clean energy, any market solution that does not accommodate this degree of VER integration will likely not be sustainable.

2. The design should result in efficient, market-based results and minimize reliance on administrative solutions.
   SCE encourages the CAISO to pursue market-based solutions to the greatest degree practicable. The alternative of administrative solutions, such as one-off contracts to individual participants for specific services or commitments, should be avoided where possible. We note that market-based solutions may, at times, require mitigation rules. However, even if mitigation is necessary, we feel that the price transparency and visibility of a market solution is typically preferable to administrative outcomes.

3. The design should recognize "Permanent seams" issues between the CAISO and other Balancing Authorities.
   The CAISO, in its current, basic footprint, will likely be the only organized market in the WECC for the foreseeable future. However, California will continue to have a significant interaction and perhaps reliance on power and services from other balancing authorities, either out of necessity or for efficiency. The CAISO's VER integration

[10] For example, the governor has discussed a proposal for 12,000 MW of localized energy and 8,000 MW of large scale renewables, by 2020. See http://www.jerrybrown.org/sites/default/files/6-15%20Clean_Energy%20Plan.pdf

should not only coexist with non-CAISO-market entities, but it should be designed to allow efficient commerce among these markets.[11] The design should be cognizant of such seams and integrate as smoothly as practicable with these external markets.

4. The design should recognize a paradigm shift in the approach to grid operations and resulting cost allocation. The grid operator's goal is no longer just to "serve load", but rather they have an additional new goal: To efficiently and reliably integrate variable and intermittent supply.
   Uncertainty and variability brought to the grid by VERs will require integrating services and likely investment to insure the CAISO maintains the operating flexibility required for grid reliability. It would be a mistake to approach market design with assumptions that are simply no longer valid (i.e. all operating actions are done on behalf of serving load, ergo, load should bear all costs of operations) since the foundational role of grid operations itself is changing. With the changes in the generation portfolio, variability and uncertainty from the supply side must be addressed as part of the core market design. Continued assumptions that variability stems solely (or primarily) from demand would in turn result in an inefficient and potentially unworkable design, and likely an untenable market outcome in the short and long term.

   SCE stresses the need to decompose costs related to addressing variability and uncertainty and then allocate these costs back to the sources causing the costs. It is essential for the CAISO to scrutinize all operating actions, all requirements for products, and the quantity of products demands, and ask the following: Are we taking this action to (a) address load and its variability/uncertainty, or (b) to integrate supply resources and address their variability/uncertainty? SCE, along with other stakeholders, raised this key point during the April 12 meeting[12].

   Basic economic principles show that incorrect assumptions lead to inaccurate models of reality. Misallocating costs will likely lead to misleading price signals and inappropriate investment in the short and long-term. In addition, what may seem to be appropriate allocation for a short-term solution may lead to larger, more consequential long-term problems and costs. Thus, a market design with improper core cost allocation will likely not be sustainable in the long run. SCE urges the CAISO to ensure cost allocations are consistent with cost-causation principles.

5. The CAISO needs to consider the proper staging of market enhancements. How the roll-out occurs after component design is critical. The electricity market has a high degree of interdependency between its various components and so the roll-out process for each component may substantially impact the performance of other components.

IV. Specific Design Issues for Consideration

SCE appreciates the analysis the CAISO has performed to try to model the future world of both a 20% and a 33% renewables mix. In addition, the issues faced by the CAISO are not unique. We

[11] If, for example, market tools such as 15 minute scheduling, are essential to enable a comprehensive model that does not ignore the permanent seams assumption, then SCE would support the CAISO in adopting such specifics.
[12] City of Pasadena, Bay Area Municipal Transmission Group, etc.

note, for example, that the Bonneville Power Administration (BPA) has seen substantial growth in wind and expects to integrate about 4,000 MW by October, 2010, and is forecasting name plate capacity of almost 6,000 MW by September, 2013. As a result of both analysis and experience, SCE observes certain issues that it feels will most likely require attention during this process. Consideration of current situations and studies faced by the CAISO and by BPA indicate certain issues will likely require attention in this Phase 2 process. Below is a list of some of these issues:

1. <u>Ensuring that the optimization provides sufficient operational flexibility.</u> CAISO studies have shown a dramatic increase in regulating, ramping and following needs[13]. Sufficient flexibility is needed to deal with both increasing variation (that is predictable/certain changes in generation output and load consumptions) and uncertainty (uncertain/unforecasted) changes in load and supply.

2. <u>Separating the use of contingency reserves from the use of "integrating reserves".</u> In the past, rapid changes in supply output were generally treated as contingency events, and in turn addressed with ancillary services (spinning and non-spinning reserves). In the new, intermittent resource world, rapid changes may be the norm, not the exception, and typically will not be classified as contingencies. Rather, these events will require services that are triggered by normal operations, rather than services reserved for contingencies.

3. <u>The design of the RT market will influence the design of other market components</u>. Ultimately, the CAISO must serve load, integrate variable production, manage imports/exports, and maintain reliability on a minute-to-minute basis. As a result, the RT market design will have a major impact on the overall efficacy of the total design. Moreover, RT design will drive how other parts of the market (i.e. the DA market) need to be integrated in to the overall design. This suggests that market design should initially focus on the RT market, and ensure it is efficient and practicable. Based on a known RT design, the rest of the market space can be addressed.

4. <u>Interaction of CAISO markets, operational requirements, and the RA process.</u> Given the operating flexibility required for intermittent integration, the CAISO must address what form of planning is necessary to ensure this flexibility exists when needed. Thus, determining if reliability necessitates integrating operating needs into the RA process should part of this process. However, consistent with cost allocation, if RA changes are needed the CAISO should determine the cause of needed operating flexibility and allocate any forward cost/responsibility back to the cause. Importantly, if the cause is intermittent generation, the current RA process cannot allocate costs directly to

[13] The CAISO reports generally refer to this as "Load Following". While this term has an historic understanding, SCE objects to the continued use of the term "Load Following" as we enter this new paradigm. "Load Following" it implies, by name, that "load" is the variation driving the "following" requirement. CAISO studies clearly show that much of the "following" is now required to address VER production. In turn, terminology such as "VER Following" or "Intermittent Resource Following" would be more accurate to describe this increased requirement. Here, SCE uses the more generic term of "Following", with the understanding this total amount can, in fact, be decomposed to a portion required to follow load, a portion required to follow VERS, and a portion required to follow other variations.

generation. That is, the current CPUC/local jurisdiction process can effectively only allocate costs/responsibility to load. Rather, only the CAISO is in a position to allocate costs directly to generation. Thus, for a proper evolution of the RA process, a solution must involve:

i. Identification of needed operating flexibility.
ii. Determining if this need should be secured on a planning basis (such as RA)
iii. Decomposition of what is driving this requirement between needs driven by load, and needs driven by generation.
iv. Allocation of the cost/responsibility based on causation to both load and generation.

This differs from the current RA process which only assigns responsibility to load. With an increasing and significant proportion of generation comprising intermittent resources, the RA process must account for generational variability and uncertainty, so the allocation of this requirement to generation must take place through the CAISO via new CAISO structures and processes.

5. <u>Better specifying and pricing constraints.</u> While the CAISO currently has a host of operating constraints, many of these constraints do not bind (and are not even modeled) given that the typical mix of resources dispatched for energy and ancillary services simultaneously satisfies these additional operating constraints. One example of a constraint typically taken for granted is inertia. Since the majority of our power currently is sourced from large, spinning machines, the system typically has abundant inertia. In fact, our understanding is given the abundance of inertia, the CAISO may not have even defined its current requirements. But with the penetration of smaller machines and technology such as solar PV, it is unclear if the system will have sufficient inertia unless constrained to ensure it. Moreover, the need for flexibility is expected to increase just as the resource mix expected to provide energy will provide less flexibility. Thus, failure to specify and enforce these "flexibility" constraints will lead to both an inefficient market that sends incorrect price signals and a resource mix that will not ensure reliability. Proper identification and pricing of constraints should encourage appropriate investment and lead to proper operating behavior in the short-term, and efficient investment in the mid/long-term. With that said, it may not be appropriate to price *every* constraint, or to translate every constraint in to a market product. Moreover, non-competitive constraints or priced products will require appropriate mitigation.

6. <u>Shorter scheduling timelines closer to RT.</u> It is crucial that the CAISO prioritize this matter. Given the influx of intermittent generation to the market, the need to schedule closer to RT is underscored by the accuracy of performance forecasts. It is also crucial that parties have the ability to leverage the diversity of the WECC very close to RT. In many ways, the RT market will be the driver of the rest of the market design. The greater the percentage of generation that is variable and uncertain, the greater the required emphasis on RT operational flexibility. SCE notes that during the recent stakeholder meeting, the CAISO represented, in effect, that the current bid submission timeline (75 minutes prior to the delivery hour) is unlikely to change, given the complexities of MRTU (submitting bids, running markets, communicating results, reserving

transmission, etc.). SCE encourages the CAISO to approach the problem differently. Rather, the CAISO should ask, "what MRTU design changes would be necessary to align the CAISO's RT markets with the rest of the WECC?" We should assume FERC will mandate shorter scheduling time-lines, perhaps as short at 15-minute schedules due 15-minutes prior to delivery. What changes would be needed to accommodate this approach?

7. Hour Ahead Scheduling Process (HASP) design/elimination. The HASP settlement process is a leading cause of inefficiency given the discrepancy in operations and price divergence and leads to inaccurate and inappropriate allocation of costs. Continuing this process status quo does not contribute to market stability, on the contrary, it deteriorates stability. This process must undergo significant redesign or be eliminated as an acceptable solution toward integrating intermittent generation. This process does not function efficiently under the current, less uncertain, system. In a more volatile generation mix, this design will cause more serious problems. The design as it exists cannot be part of a feasible integration solution.

8. Better modeling of operating flexibility and costs. The CAISO studies indicate that thermal units will typically experience more frequent cycling, startups, and shutdowns. The CAISO Multi-Stage Generation (MSG) efforts are a step in the right direction for modeling flexibility. For efficient market outcomes, participants must be able to accurately represent their startup and shutdown costs, as well as any other increased costs associated with cycling. The current market design is not robust in this dimension and must be given attention. For example, participants cannot currently represent a combination of fixed and fuel-based startup costs, rather they can only submit a fuel quantity or a fixed aggregate dollar amount.

V. Cost Allocation Methodology

In the CAISO stakeholder meeting, the CAISO solicited specific ideas for design elements. Below we discuss approaches to the decomposition of cost allocation. We note these items are for background and to help guide discussion at this time, and SCE remains committed to working with the CAISO and other stakeholders to develop an appropriate and practical methodology as the overall design takes shape.

(a) The BPA Methodology of Decomposition:

An example of contemporary cost allocation is the one used by the BPA. In general, BPA first determines the total amount of "balancing reserves" it needs to operate its grid. It holds three types of balancing reserves broken up into pairs based on incremental and decremental needs:

1. Regulation INC (4-second response)
2. Regulation DEC
3. Generation Imbalance energy INC
4. Generation Imbalance energy DEC
5. Following INC(ramping capability dispatched every 10-minutes)
6. Following DEC.

Based on a historical look-back based on actual performance in the preceding two years, BPA adjusts for changes in generation and load, then forecasts the balancing reserves required to operate the grid reliably for 99.5% of all 10-minute intervals.

With the *total* amount of balancing reserves calculated, BPA then decomposes this total and allocates the associated cost responsibility to wind, solar, BPA hydro and thermal resources. Load variations were small and included with hydro.

In sum, BPA forecasts required operating flexibility, uses cost-of-service principles to determine how much this flexibility costs, determines cost-causation of this total need based on resource class, and then allocates each resource class its share of the costs[14].

The decomposition methodology is summarized below for INC Regulation. For each resource, the BPA uses the maximum of the regulation requirements for 99.5%[15] of its regulation reserve dataset for each hour. The maximum regulation reserve is then used to determine the resource's contribution to regulation reserve need. The allocation proportion is determined by the correlation between the regulation needed by the resource and the total regulation needed. The allocation proportion is also determined by the standard deviation of the regulation needs of the resource and the standard deviation of the distribution of total regulation needs. An example of this can be seen with the allocation to incremental wind regulation requirement:

$$Share_{inc}(wind) = Reg_{inc}(total) \times \rho_{Reg_{inc}(wind),Reg_{inc}(total)} \left(\frac{\sigma_{Reg_{inc}(wind)}}{\sigma_{Reg_{inc}(total)}} \right)$$

$$\begin{aligned}&where\colon \rho = correlation, \sigma = standard\ deviation,\\ &Reg = regulation\ requirement,\\ &Share = \ allocation\ of\ regulation\ to\ resource\end{aligned}$$

Thus, the share of a resource's cost is allocated from the total regulation procurement based on the correlation of procured regulation as well as the standard deviations of total and resource required regulation. It can be seen that incorporating the standard deviation accounts for resource variability.

[14] Detailed testimony on this methodology can be found at:
http://www.bpa.gov/corporate/ratecase/2012/docs/bp-12-E-BPA-23.pdf
http://www.bpa.gov/corporate/ratecase/2012/docs/bp-12-E-BPA-24.pdf
http://www.bpa.gov/corporate/ratecase/2012/docs/bp-12-E-BPA-25.pdf
http://www.bpa.gov/corporate/ratecase/2012/docs/bp-12-E-BPA-05.pdf
http://www.bpa.gov/corporate/ratecase/2012/docs/bp-12-E-BPA-05a.pdf

[15] Excluding 0.25% of its extreme incremental and decremental regulation values.

While not perfect, the BPA approach is a commendable step in the right direction. It not only incorporates (i) the relation between total regulation and resource-specific needs but also (ii) the effect of a resource's needs on the system altogether. This approach takes-apart the component resources in a generation portfolio and tries to accurately assign costs based on individual effects on the entire system. The BPA's approach at decomposition is what prompts SCE to present the alternative methodology below for discussion.[16]

(b) The Westar Methodology of Decomposition:
Westar offers another contemporary approach. Westar's approach to cost-allocation stemmed from its one year study of regulation requirements of intermittent generators under Schedule 3A. In its ER09-1273-000 filing, the FERC found that "Westar's proposal reasonably assesses intermittent generation a higher regulation requirement consistent with cost causation principles".

Westar's cost-allocation methodology stemmed from a 2005 – 2006, one year period study of wind sites in central, eastern, and western Kansas. 10-minute interval output data were observed and these were aggregated within these three geographic groups over each 10-minute interval for the year. This ensured that the study accounted for geographical locational disparity across generators. For each of these three geographic groups the difference between outputs of 10-minute intervals was recorded. The standard deviation of these differences was calculated for each group's distribution of differences. Westar then determined regulation requirement for intermittent generators as:
$Share(i) = \frac{2 \times \sigma_{differences\ for\ group\ i}}{\sum_{i=1}^{3} nameplate_{group\ i}}$ which determined a 7.8% of nameplate capacity to be the regulation requirement. In a subsequent portfolio-wide study, Westar determined the regulation requirement for intermittent resources to be 4.05% due to partially offsetting deviations.[17] Both percentages were higher than

[16] However, unlike BPA's approach, SCE's approach is not based on portfolio theory. There is some irrelevance of portfolio theory to regulation requirements. Some points arguing against the BPA approach are:

(1) Using the CAPM (Capital Asset Pricing Model), we have the expected return, R, on security i, being related to the market, M, and risk-free, f, returns as: $R_i = \beta_i(R_M - R_f) + R_f$. Here, $\beta_i = \rho_{i,m}\frac{\sigma_i}{\sigma_m}$, which is used by BPA to determine the proportion (of the total regulation) for each resource. The issue here is that the concept of excess return $(R_M - R_f)$ over the risk-free rate is meaningless for regulation. The closest analogy would be excess regulation needs over a benchmark (comprising of all generation) regulation needs. First, such a benchmark is inappropriate given balancing authority specificity of generation. Second, the risk-return relation in finance is not relevant to generation performance. Third, a resource A's regulation requirement can have a high correlation with total regulation requirement and have a low variance in regulation requirement while a resource B can have the relation vice versa. In that case, the allocations would be equal for both resources but not necessarily appropriate.

(2) BPA's approach ignores that several independent variables (regulation needs of different resources) contribute to total regulation needs as a whole. Decomposition of their effects must be examined within an entire system rather than assuming that each resource can be considered in isolation. The $\beta_i = \rho_{i,m}\frac{\sigma_i}{\sigma_m}$ measure is the coefficient of regression when considering two variables in isolation. A multiple regression is required to relate the effects of several resource regulation requirements on the total requirement.

[17] The discrepancy between the allocations provides support for the next proposal of decomposition via regression. In order to consider a portfolio of resource's while minimizing estimation error, a multiple regression is a promising tool.

the 1.24% for non-intermittent resources – a result that the FERC found appropriate, thus directing a higher regulation charge for intermittent resources.

(c) Decomposition via Regression:
One possible alternative approach could be a multiple regression. It is simple and straightforward and does not assume analogies to other markets. Within the BPA context, the total INC regulation required, that is forecast by resource required INC regulation, would then be:

$$RT = a + b_l RL + b_w RW + b_h \mathrm{RH} + \cdots$$

$where: RT = total\ inc\ regulation, RL = load\ inc\ regulation,$
$RW = wind\ inc\ regulation, RH = hydro\ inc\ regulation, a = intercept,$
$b_l = incremental\ regulation\ to\ total\ inc\ per\ unit\ increase\ in\ load\ inc\ regulation, b_w = incremental\ regulation\ to\ total\ inc\ per\ unit\ increase\ in\ wind\ inc\ regulation, b_h = incremental\ regulation\ to\ total\ inc\ per\ unit\ increase\ in\ hydro\ inc\ regulation$

Intercept 'a' is ideally zero[18] thus the effect on total regulation is due to the incremental effects of regulation. Since each regression coefficient is the incremental effect of its respective regressor on the dependent variable, allocation to resource "i" would then be:

$Share(i) = \frac{b_i}{\sum_{t=1}^{n} b_t}$, for 'n' resources, with INC and DEC regulation separately allocated in this manner.

(c) Combined *Ex Post* and *Ex Ante* Decomposition:
Another alternative approach (which could incorporate either the BPA or the multiple regression approach) would involve an *ex ante* and *ex post* decomposition of costs:

1. The *ex post* component would charge a resource based on its share of total regulation, $\frac{resource\ regulation\ need}{total\ regulation\ procured}$, at, for example, the end of the hour.
2. The *ex ante* component would charge a resource or class of resources based on individual past performance or the past performance of the resource classes. The remainder of the share of charges not covered by the *ex post* component would be assigned based on historical performance.

For example, consider Resource A that requires 2 MW of regulation while the CAISO procured 100 MW in total to meet all system needs. If no other resource required regulation in a given hour (i.e. every other generator performed exactly to schedule every second), A would be charged for 2 MW, *ex post*. Consider also Resource B that typically requires 90% of regulation procurement while Resource A makes up the remainder based on historical performance. The *ex ante*

[18] A resource portfolio with no generation or load variation would, under this model, not need any regulation.

component would then charge Resource A for 10% of the remainder (98 MW = 100 – 2 MW) or 9.8 MW. Resource B would be charged 90% of 98 MW or 88.2 MW.

This method not only provides further cost-causation decomposition but also provides an incentive for resources to require less regulation over time since they are gauged also by their track record and not just performance during a particular hour.

While these methods comprise a list of current approaches in the field of cost decomposition and allocation, the list is not exhaustive. Further, each method is proposed for exploratory purpose and is not necessarily the right way (certainly not the only way) of accurate cost decomposition and allocation. SCE encourages the CAISO to explore cost decomposition/allocation through detailed stakeholder processes.