UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Modernizing Electricity Market Design   Docket No. AD21-10-000

NOTICE INVITING POST-TECHNICAL CONFERENCE COMMENTS

(December 6, 2021)

On September 14, 2021 and October 12, 2021, the Federal Energy Regulation Commission (Commission) convened staff-led technical conferences to discuss energy and ancillary services markets in the evolving electricity sector.

All interested persons are invited to file initial and reply post-technical conference comments on the topics in Parts I and II below, which contain the questions posed in each technical conference agenda. Commenters may reference material previously filed in this docket, including the technical conference transcripts, but are encouraged to avoid repetition or replication of previous material. Commenters need not answer all of the questions, but commenters are encouraged to organize responses using the numbering and order in the below questions. Initial comments must be submitted on or before **February 4, 2022**. Reply comments must be submitted on or before **March 7, 2022**.

I. Comments on Supplemental Notice for September 14, 2021 Technical Conference

We are seeking comments on the topics discussed during the technical conference held on September 14, 2021, including responses to the questions listed in the Supplemental Notice issued in this proceeding on September 13, 2021 in accordance with the deadlines and other guidance above. The questions from the agenda are included below.

Panel 1: Understanding the Need for Additional Operational Flexibility in RTO/ISO Energy and Ancillary Services Markets

1. RTOs/ISOs and other industry experts generally agree that power systems will require greater flexibility from system resources in the future.[1] What operational capabilities or services will be most valuable to RTO/ISO operators in the future as the resource mix and net load profile changes and why? Is there a desirable

[1] *See, e.g.*, CAISO, *Day-Ahead Market Enhancements Revised Straw Proposal*, at 7 (June 2020); SPP, *Uncertainty Product Whitepaper*, at 6 (Mar. 2020); NYISO, *Reliability and Market Considerations For A Grid in Transition*, at 8-9 (Dec. 2019).

reaction time, sustained performance duration, etc. expected from a resource?

2. To what extent will the "traditional ancillary services" defined in Order No. 888[2] and existing energy market designs continue to ensure reliability as the resource mix changes in RTO/ISO markets in the future?

    a. Will traditional ancillary services provide the appropriate types and adequate quantities of operational flexibility RTOs/ISOs need to manage both expected (e.g., reasonably predictable) and unexpected (e.g., inherently uncertain and captured in forecast errors) variability in net load?

    b. Will existing RTO/ISO energy and ancillary services market designs that generally compensate certain traditional ancillary services resources based on the opportunity cost of foregone energy sales – for example, spinning and non-spinning reserves - give resources a sufficient economic incentive to offer their flexible capabilities to the RTO/ISO?

NHA comments:

- Increased penetration of variable energy resources (VERs) will require different amounts of traditional ancillary services and potentially new products
    - I.e. fast-responding reserves and regulation will likely increase in quantity. Operating reserves are currently designed around 1st and 2nd contingencies (typically a large generator trip or transmission outage). The future system will likely need additional reserves above this amount to account for both supply and demand uncertainties, forecasting errors and to ensure firm supply.
    - For ISO-NE in particular, NHA supports efforts to implement DA reserve products including energy imbalance reserves and replacement reserves. Absent a DA reserve market, ISO will continue to lean on reserve capable resources without compensation for their high call option value.

[2] Order No. 888 required the following six ancillary services be offered in an open access transmission tariff: (1) Scheduling, System Control and Dispatch Service; (2) Reactive Supply and Voltage Control from Generation Sources Service; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve - Spinning Reserve Service; and (6) Operating Reserve - Supplemental Reserve Service. Order No. 888, FERC Stats. and Regs. ¶ 31,036, at 31,703 (1996).

- (from brattle report) Calculation of opportunity costs is critical to maximizing the value of all energy limited resources including storage resources like chemical batteries, pondage hydro and pumped storage
  - Accurately calculating these costs is difficult because it often requires developing estimates of future energy prices and foregone revenue. To the extent that new or expanded E and AS products are co-optimized using opportunity costs, how RTOs allow for opportunity cost accounting will become even more significant for flexible hydro and pumped storage.
  - I.e. this will require greater communication between hydro owners and RTOs to better address changing system conditions. One example of this problem is the delay in allowing for updates in opportunity costs. In CAISO, opportunity costs are not immediately updated. So while a daily unexpected change in reservoir levels can change a units foregone energy potential, that change may take a week or more to be reflected in opportunity costs.
  - Inaccurate estimates of opportunity costs could lead to flexible units choosing to self-scheduling potentially reducing the value both to the system and to the owner.

3. How should RTOs/ISOs define the system's need for operational flexibility, now and in the future?
   a. To what extent is operational flexibility needed on a bi-directional basis (i.e., both up and down) versus a unidirectional basis (i.e., only up or down)?
   b. How do these needs compare to the services provided by traditional ancillary service products?
4. Could variable energy resources or new resource types (e.g., storage, hybrid, and co-located resources) be operated or dispatched differently from the status quo to provide greater operational flexibility to the RTO/ISO, if so, how? Given the evolving resource mix, are the current eligibility requirements for each resource type to provide ancillary services appropriate?

Panel 2: Revising Existing Operating Reserve Demand Curves (ORDCs) to Address Operational Flexibility Needs in RTOs/ISOs

1. Contingency reserves are provided by existing 10- and 30-minute reserve products

and are designed to ensure the system can recover from a contingency (e.g., a generator or transmission outage). How will the procurement of additional contingency reserves help RTO/ISO operators manage routine operational flexibility needs (e.g. needs driven by net load variability and uncertainty)?

2. What are the benefits of procuring contingency reserves beyond the minimum reserve requirement through a given ancillary service product?

    a. If employing such a method, how should RTOs/ISOs determine the market's demand for contingency reserves (both the quantity and willingness to pay) beyond the minimum reserve requirement of a given contingency reserve product?

    b. What principles should RTOs/ISOs follow if they consider revising the shape of the ORDC for a given contingency reserve product (e.g., introducing additional steps or graduation to the ORDC curve)? For example, should the willingness to pay for such additional reserves be based on the Value of Lost Load times the loss of load probability with a given quantity of the reserve product associated with the ORDC, the cost of actions operators would take to procure additional reserves, or some other valuation method? How should customer willingness to pay be incorporated?

3. Reserve shortage prices are administratively determined penalty factors invoked when the system falls below the minimum requirement of one or more reserve products. To what extent can higher reserve shortage prices inform investment decisions and reflect the value of flexible resource capabilities?

    NHA Comments:

    - All else equal, better reserve shortage pricing will encourage flexible and highly available resources to operate consistent with changing system conditions. ORDCs (operating reserve demand curve) are one way to encourage flexible resources like hydro and pumped storage to maximize output while supply is scarce.

    - RTOs and ISOs could also adjust their AS procurements as the level of VERs increase. ERCOT, for example, procures regulation up and down to cover at least 95% of the recently observed interval change in net load. Similarly, RTOs could set non-spinning reserve procurements based upon observed net load uncertainty and ramping needs.

a. What principles should RTOs/ISOs follow if they consider revising the shortage price associated with the ORDC of a given contingency reserve?

b. How should the shortage prices of individual contingency reserve products be determined? For example, should the shortage prices reflect the marginal reliability value of each individual reserve product? How should customer willingness to pay be incorporated?

c. How should shortage pricing be implemented when the system is short both 10- and 30-minute reserves? Does establishing shortage prices based on the marginal reliability value of each contingency reserve product that is in shortage ensure that adding the shortage prices reflects the combined reliability impact of being short of those reserve products?

d. Do differences in shortage prices across regions present operational challenges today? Is there an expectation that such differences could present operational challenges in the future as the resource mix and load profiles change? Is there a need to better align shortage pricing across RTOs/ISOs, and if so, what principles should be considered in doing so?

4. To what extent do RTOs/ISOs use contingency reserves to manage non-contingency related operational uncertainties (e.g., expected and unexpected net load variability)? If such reserves are used for this purpose, should this alter an RTO/ISO's approach to establishing the maximum height and shape of the ORDC? Under such approaches, how do prices in the ORDC appropriately reflect the marginal reliability value contingency reserves provide?

- The transition to a low carbon grid is already creating more operational uncertainty than existed just a decade ago. While reserves have been used to cover traditional contingency needs per NERC requirements, VERs and other demand side energy trends are leading to greater uncertainty for grid operators.

- These non-contingency related operational uncertainties should be accounted for during the unit commitment process, not after that commitment has been made (to the extent possible). To meet contingency reserve needs, RTOs/ISOs must be able to meet demand in cases where the day ahead cleared demand is under forecasted or where the forecasted VER generation falls short. To accurately price contingency reserves, the other needs must also be factored into the co-optimized energy and reserve market design. This issue was one of the main drivers behind ISO-NE's ESI Filing, recognizing the interplay between GCR, EIR and RER in its own day ahead unit commitment process to deliver a reliable next day operating plan.

5. Is there a particular point at which procuring reserves beyond the minimum reserve requirement can reduce or conflict with the objectives of shortage prices? What is an appropriate balance between raising shortage prices and procuring reserves beyond the minimum reserve requirement given that procuring additional reserves can reduce the probability of the RTO/ISO experiencing a shortage?

   Yes. Actions that operators take in the unit commitment process will have an impact on reserve pricing. The more reserves RTO/ISOs create through the unit commitment process, the greater downward pressure there will be on energy prices. In ISO-NE, many resources committed in DA have significant operational constraints including minimum operating limits and run times. These operational constraints can greatly influence price formation of reserves in the DA market. The reserve requirement should be the amount of fast start plus additional reserves the ISO schedules from synchronized resources. Absent such a mechanism, the ISO will continue to rely on flexible resources like pumped storage that provide reserves from an offline state but are not compensated for such.

Panel 3: Creating New Products to Address Operational Flexibility Needs in RTOs/ISOs

1. Ramp products, as distinguished from traditional ancillary service products, are relatively new ancillary services that are in place in CAISO and MISO, and approved for implementation in SPP. Ramp products are generally *not* designed to address contingencies[3] but are instead a mechanism to position the system efficiently to meet forecasted ramping needs in future intervals at least cost on an expected basis.

   a. RTO/ISO ramp products procure ramp on a short-term basis (e.g., for intervals of 10 or 15 minutes), but longer-term ramp products are being considered. For example, SPP is considering a longer-term ramp product[4] and the California Department of Market Monitoring has advised CAISO to

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[3] For example, ramping products are not designed to be substitutable with the reserve products used for managing contingencies. *See e.g.* CAISO, *Flexible Ramping Products Straw Proposal* at 7, 10 (Nov. 1, 2011) http://www.caiso.com/Documents/FlexibleRampingProductStrawProposal.pdf; Sw. Power Pool, Inc., Filing, Docket No. ER20-1617-000, at 13 (filed Apr. 21, 2020).

[4] *See* Sw. Power Pool, Inc., "RR449 – Uncertainty Product" (July 27, 2021), https://www.spp.org/Documents/64125/rr449.zip. *See also* Sw. Power Pool, Inc., *Uncertainty Product Prototype Design Whitepaper* (Mar. 13, 2020).

consider a longer-term ramp product.[5] What drives the need for, and what are the benefits of, a longer-term ramp product compared to the existing shorter-term ramp products or traditional reserve product

NHA Comment: There is some overlap between new ramping or load following products and proposed changes to operating reserve demand curves. Existing short term ramp products are generally designed to address (mostly) expected changes in net load. ORDCs can improve the system's response to a scarcity of operating reserves to meet a number of contingencies. The nature and extent of expected and unexpected contingencies in both supply and demand is rapidly shifting. Each individual system needs should drive the design of new products. While ramping products, if properly designed, can position a system to meet forecasted net load variability, it may not be the best tool to address evolving contingency drivers. The important point is that each new product design cannot be viewed in isolation. For instance, the effectiveness of these products can be influenced by several factors including how the grid operator commits units (both during and after the DA market clearing), out of merit dispatches, how opportunity costs are calculated and reserve forecast biasing. All of these, in addition to any capacity market obligations, should be considered when designing new flexible products to ensure the efficient and reliable dispatch of resources.

2. Will establishing reserve and ramp prices based on foregone energy revenues provide such signals in a system with a high penetration of variable energy resources, many of which have low or zero marginal costs?

   a. If not, what other options exist to ensure sufficient compensation for resources providing reserve and ramp capability?

   b. Historically, the prices for the ramp products in CAISO and MISO have often been zero. Are ramp prices expected to increase over time as system needs evolve? If so, what specific conditions might cause ramp prices to increase? Will any expected ramp price increases be sufficient to incent and appropriately compensate the ramp capability RTOs/ISOs and others expect will be needed due to the changing resource mix

NHA Comment: Ramp products are still new and the RTOs who have them are already considering significant reforms. That said, from a generator's perspective, the resulting

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[5] CAISO Department of Market Monitoring, Comments on Issue Paper on Extending the Day-Ahead Market to EIM Entities, at 8 (Nov. 22, 2019).

revenue from flexible products has not resulted in adequate revenue that will meaningfully incent and reward generators for their flexibility. For example, the flexible ramping product in CAISO generated $3.6 million for generators in 2020 of which 39% were paid to hydropower generators. Hydropower owners and operators provide immense operational flexibility to RTOs/ISOs on a daily basis. This includes ramping, fast start, all energy and ancillary service products, black start, and voltage control all while doing so on a non-emitting basis. Many of the hydropower power plants are offering an amount of flexibility to grid operators that was not initially contemplated for in the original design of the equipment.

There are several costs associated with this flexibility including but not limited to increased maintenance, accelerated equipment degradation, lost generation opportunity, lost water and reduced efficiency. In addition, many hydro owners face conflicting multi-purpose tradeoffs between power generation and other uncompensated public benefits like flood control, irrigation and recreation. It is therefore essential that flexibility-based products be designed to not only recover foregone energy but to recover availability costs – the revenue lost from increased outages attributable to starts/stops, water energy costs – water used to start during no-load and efficiency costs – as a runner wears, it takes more water to generate a given amount of electrical energy.

Energy markets do allow for a value for variable O&M cost however, these bid parameters cannot price the difference in wear and tear distinctions between operating a static output level in an hour and frequent dispatch changes within the hour. A unit that is dispatched to a higher level in one five minute interval staying static through several intervals is much different than a unit that is dispatched up and down frequently in the same period. These two scenarios can result in very different impacts on moving parts.

3. CAISO is considering a Day-Ahead Energy Market Enhancement proposal that seeks to ensure that the day-ahead market clears sufficient resources to address expected net load variability and uncertainty that arises between day-ahead and real-time. What are the expected advantages and disadvantages of revising the day-ahead market construct in this way to procure additional operational flexibility?

4. The Electric Reliability Council of Texas, Inc. (ERCOT) has proposed to procure fast-responding, limited duration products to address primary frequency control issues associated with declining system inertia.[6] CAISO also intends to initiate a stakeholder process to discuss, among other options, compensating internal

[6] *See* Pengwei Du et al., *New Ancillary Service Market for ERCOT*, IEEE Access Volume 8, https://ieeexplore.ieee.org/abstract/document/9208672.

resources for the provision of primary frequency response.[7] What are the merits of such reforms and should they be considered in other regions?

5. What other new products not yet discussed at this conference, do you think could increase operational flexibility in RTOs/ISOs?

   a. Can capacity markets or other, potentially new, "intermediate" forward market constructs that clear between existing capacity market auctions and the day-ahead timeframe help ensure that RTO/ISO operators have sufficient operational flexibility in real time?

   b. For example, can a new shorter-term forward market to procure expected operational flexibility needs held closer to the delivery period (e.g., three months ahead as opposed to three years ahead) and with a more granular delivery period than the annual capacity market (e.g., monthly or seasonal delivery period, or a delivery period based on the hours of an RTO/ISO's morning or evening ramp as opposed to the annual delivery period of most RTO/ISO capacity markets) help ensure that RTO/ISO operators have sufficient operational flexibility in real time?

NHA comments: As mentioned above, reforms to energy and ancillary service markets cannot happen in isolation from the capacity market. Capacity markets are meant to assure grid operators that enough resources will be available to reliably meet demand in the future. These markets require sellers to offer into the DA and RT markets at their full design capabilities. For the same capacity price, resources are offering into a market with very different unit characteristics and economics for the DA and RT. Some capacity resources are available on a daily basis with economic bids that ensure they will likely run in real time. These resources support the system reliably and incur significant operations and maintenance costs. Other capacity resources, with longer start up times, lengthy minimum run times, or out of the market bids are rarely called upon. These two types of resources are largely compensated the same in capacity markets. While some capacity markets place performance-based obligations on sellers, these obligations have rarely been triggered and do not adequately incent resource's to perform flexibly.

Panel 4: Market Design Issues and Tradeoffs to Consider in Reforms to Increase Operational Flexibility in RTO/ISO Energy and Ancillary Services Markets

1. To date, most RTOs/ISOs have pursued new ramping products or ORDC reforms, but not both. What are the tradeoffs to consider when deciding between these two approaches and how do they interact? Should these two types of reforms be

[7] *See* CAISO, *2021 Three-Year Policy Initiatives Roadmap and Annual Plan*, http://www.caiso.com/InitiativeDocuments/2021FinalPolicyInitiativesRoadmap.pdf.

considered substitutes or complements? Does the opportunity-cost-based method of establishing reserve and ramping product prices send appropriate long-term signals to resources to invest in or maintain flexible capabilities?

2. Some entities have observed that offering additional resource capabilities into energy and ancillary services markets may not be in the financial interest of certain resources because doing so could lower energy prices by either avoiding scarcity conditions or obviating the need to commit more expensive units, and thus reduce their expected energy and ancillary services markets revenue. Are such incentive issues relevant in the context of reforming energy and ancillary services markets to address operational flexibility needs? If so, how should such issues be addressed?

3. What other market design issues and tradeoffs should RTOs/ISOs, stakeholders, and regulators consider when designing and implementing reforms to energy and ancillary services markets to increase operational flexibility?

4. What are the tradeoffs to consider in procuring flexibility in the energy and ancillary services markets versus the capacity market or another new shorter-term forward market construct?

II. Comments on Supplemental Notice for October 12, 2021 Technical Conference

We are seeking comments on the topics discussed during the technical conference held on October 12, 2021, including responses to the questions listed in the Supplemental Notice issued in this proceeding on October 7, 2021 in accordance with the deadlines and other guidance above. The questions from the agenda are included below.

Panel 1: Incenting Resources to Reflect Their Full Operational Flexibility in Energy and Ancillary Services Offers

1. Do any existing RTO/ISO energy and ancillary services market participation rules, supply offer rules, eligibility requirements, and relevant procedures encourage certain resources to offer into the market inflexibly (i.e., without reflecting the full range of their physical operating capabilities)? For example, are any changes to resource supply offer rules or uplift eligibility requirements needed to ensure resources submit physical offer parameters (e.g., notification time, minimum run time, ramp rates) that reflect their flexible capabilities? To what extent do RTOs/ISOs account for existing fuel limitations, like natural gas supplies, that have the potential to impact resource flexibility?

2. Do any existing RTO/ISO energy and ancillary services market rules exhibit an undue preference for certain resource types over other resource types? If so,

please explain how and provide examples.

3. To what extent do existing self-scheduling or self-commitment rules in RTO/ISO markets reduce the amount of operational flexibility available to the RTO/ISO in real time and the system's need for operational flexibility? Are options for self-scheduling and self-commitment needed to allow resource owners to make the best use of their assets over time?

4. Do current RTO/ISO offer rules, market power mitigation practices, and reference levels prevent or discourage resources from including in their offers the additional costs, if any, that resources incur from being more flexible (e.g., longer-term wear and tear on natural gas resources due to increased cycling, battery warranty considerations, etc.)? Are such costs difficult to quantify? If so, please explain why. How should RTOs/ISOs review such costs to ensure that resources' energy and ancillary services supply offers are competitive?

NHA Comment: As mentioned above, the extent to which RTO and ISO rules allow for a wide range of costs to be included in energy bids the more likely that hydropower resources (and other flexible resources) will perform at their full operational flexibility. NHA is not aware of RTOs/ISOs that explicitly allow for longer term wear and tear on turbine runners and other generating equipment. These costs are difficult to determine however, they are real and can influence a generator's willingness to offer in economically rather than self-scheduling.

There are many reasons generators choose to self-schedule. Self-scheduling is needed to manage both physical and financial positions. Hydro projects have a multitude of different operating regimes, license constraints and multi-purpose objectives to balance. Without an option to self-commit their resource, these competing factors would be impossible to manage through energy bids or RTO commitment. For example, a hydro operator may need to make room in the reservoir for an approaching storm. The more that markets can value flexibility with adequate compensation, the more likely resources will choose to bid economically rather than relying on self-scheduling.

Panel 2: Maximizing the Operational Flexibility Available from New and Emerging Resource Types

1. Do existing RTO/ISO energy and ancillary services market rules, practices, or procedures prevent or otherwise obstruct relatively new and emerging resource types from fully participating in RTO/ISO markets and offering the operational flexibility they are technically capable of providing?

2. To what extent do existing RTO/ISO energy and ancillary services market rules require standalone variable energy resources to respond to dispatch instructions (e.g., curtailment)?

a. To what extent are standalone variable energy resources technically capable of being "dispatchable?" Is there a distinction between being dispatched down and being curtailed?

b. Under what circumstances can a standalone variable energy resource be dispatched up versus down?

3. To what extent do resource capabilities vary amongst different classes and vintages of variable energy resources (e.g., newer vs. older wind turbine models, onshore vs. offshore wind, fixed-tilt vs. tracking solar, etc.) and do offer rules currently reflect such differences, if any?

4. To what extent are emerging resource types, such as hybrids, storage resources, and distributed energy resource aggregations technically capable of providing existing ancillary service products or other reliability services? Acknowledging that some market rules are evolving due to Order Nos. 841[8] and 2222,[9] do current RTO/ISO market rules for ancillary services and other reliability services, such as eligibility requirements, align with these emerging resource types' capabilities?

5. What RTO/ISO energy and ancillary services market reforms could be adopted, if any, to ensure that new and emerging resource types are able to offer their full operational capabilities into RTO/ISO energy and ancillary services markets to help operators manage changing system needs?

a. Would shortening the day-ahead market interval length increase the operational flexibility available from resources? What considerations (e.g., computing time) are important to consider when establishing the length of energy and ancillary services market intervals?

b. RTOs/ISOs often require resources that provide ancillary services to be capable of doing so for a duration of 60 minutes. Does this eligibility requirement limit the pool of resources available to offer ancillary services into RTO/ISO markets? Would reexamining the need for this particular eligibility requirement present reliability concerns or raise other issues for

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[8] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 83 FR 9580, 162 FERC ¶ 61.127

[9] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 85 FR 67094, 172 FERC ¶ 61,247

operators? If so, please explain.

Panel 3: Revising RTO/ISO Market Models, Optimization, and Other Software Elements to Address Operational Flexibility Needs

1. What are the challenges to incorporating uncertainty within the current RTO/ISO market software? For example, how can improvements in forecasting, the use of intra-day commitment processes that include a range of forecasts, or longer look-ahead commitment and dispatch horizons result in more efficient unit commitment and dispatch in real time?

2. Can changes to RTO/ISO unit commitment and dispatch software address the need to posture system resources optimally to meet expected and unexpected ramp and operational flexibility needs?

    a. How are these enhancements tailored to the expected magnitude of forecast errors in different time periods?

    b. How would multi-period dispatch modeling in the real-time market help address operational flexibility needs? What are the advantages and disadvantages of a binding as opposed to an advisory multi-period dispatch model?

    c. What are the computational burdens associated with such modeling enhancements?

3. To what extent can software enhancements for modeling specific technology types (e.g., multi-configuration modeling of combined cycle units, storage, etc.) help address the system's changing operational needs?

4. Can multi-day-ahead markets or hour-ahead markets help address operational flexibility needs in RTOs/ISOs? What is the objective of such approaches, and are there potential drawbacks?

Panel 4: Out-of-Market Operator Actions Used to Manage Net Load Variability and Uncertainty

1. RTO/ISO reports and filings to the Commission indicate that at times operators take out-of-market actions to address net load uncertainty. What impacts do such actions have on price formation in RTO/ISO energy and ancillary services markets? How strong are those impacts, both in terms of individual instances of operator actions and in terms of more general effects on the efficiency of the markets?

2. Do RTOs/ISOs anticipate that, without RTO/ISO market reforms, out-of-market

operator actions will increase over time in response to changing system needs?

3. To what degree, if any, do out-of-market actions by operators undermine RTO/ISO energy and ancillary services market reforms, such as operating reserve demand curve reforms or ramp products, designed to incent resources to provide RTO/ISO operators with the operational flexibility needed to manage the system?

4. How can RTOs/ISOs best mitigate the risks of out-of-market operator actions undermining incentives for resource operational flexibility, to the extent such risks exist?

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