UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Climate Change, Extreme Weather, and Electric System Reliability	Docket No. AD21-13-000

Post-Technical Conference Comments of the
California Independent System Operator Corporation

I. Introduction

The California Independent System Operator Corporation (CAISO) submits these post-technical conference comments in response to the Commission's August 11, 2021 notice inviting comments on various issues regarding the threat to electric system reliability posed by climate change and extreme weather events.[1] As stated in the CAISO's prior comments, any Commission action in this proceeding should help identify and rethink strategies for the electric industry to prepare for, adapt to, and mitigate the threat to electric system reliability posed by climate change and extreme weather events. In identifying any strategies, the Commission should consider regional differences, the need for regional flexibility, and the efforts already underway in the various regions to address the threat posed climate change and extreme weather events. The CAISO offers brief answers to the questions set forth in the Commission's August 11, 2021 notice.

---

1 *Notice Inviting Post-Technical Conference Comments* dated August 11, 2021 in Docket AD21-13.

II. CAISO Reponses to Questions

1. Multiple panelists at the technical conference suggested that utilities and other industry participants should engage in an assessment of climate change risks to their systems. Should public utilities be required to engage in either a one-time assessment or periodic assessments of climate change risks to their assets and/or on how their system is expected to perform under expected climate change driven scenarios? If so, should such requirements be incorporated into jurisdictional local transmission planning and/or regional transmission planning/cost allocation process tariff provisions? Similarly, should such requirements be incorporated into FERC-jurisdictional resource adequacy tariff provisions?

The CAISO's current transmission planning process includes assessments to account for climate change risks. From a system perspective, the CAISO incorporates demand forecasts developed in coordination with the California Energy Commission that reflects extreme heat events as well as energy policies to mitigate the impacts of climate change, *e.g.*, energy efficiency. The CAISO works with local regulatory authorities, including the California Public Utilities Commission (CPUC), to ensure transmission system reliability under changing climate and resource scenarios. The CPUC develops resource portfolios that reflect long-term efforts to address climate change, including scenarios to reduce greenhouse gas emissions consistent with state policy goals. The CAISO incorporates these resource portfolios into its transmission planning process to inform the need for transmission upgrades or additions.

The CAISO's annual transmission system reliability assessment also considers specific climate changes risks, as appropriate. For example, the CAISO studies a series of sensitivities in additional to its base scenarios as part of its transmission planning reliability assessment. These sensitivities include scenarios with higher forecasted load, heavy renewable generation, and minimum gas generation commitment.[2] The CAISO has also studied in its planning process the opportunities for transmission development to mitigate the risk of outages driven by "public safety power shut-off" events wherein transmission owners remove facilities from service during high risk periods to minimize risk of igniting fires,[3] although this risk is often more effectively addressed through transmission owner hardening programs. The CAISO also considers climate change impacts on generation resources, specifically for hydroelectric resources, by considering drought conditions when establishing generation levels in its base case assumptions.[4]

The CAISO Planning Standards enable the CAISO to plan new transmission infrastructure to address extreme events. Currently, the CAISO has an Extreme Event Reliability Standard for the San Francisco Peninsula given its unique characteristics, but the CAISO Planning Standards allow the CAISO to consider other areas of the system on a case-by-case basis.[5]

The changing resource mix and evolving risks posed by climate change and extreme weather require both California and other Western States to consider changes to their resource adequacy programs and how these programs work together to support reliability in the region. The CAISO, in coordination with its stakeholders, continues to evaluate whether it has the right resource adequacy planning standards and resource

---

2 *See* CAISO 2021-2022 Transmission Planning Process Unified Planning Assumptions and Study Plan, pp. 38-39, http://www.caiso.com/InitiativeDocuments/Final2021-2022StudyPlan.pdf.

3 *See* CAISO 2020-2021 Transmission Plan, "PG&E Area Wildfire Impact Assessment", Page 420, http://www.caiso.com/Documents/BoardApproved2020-2021TransmissionPlan.pdf

4 *Id.* at 24.

5 CAISO Planning Standards, Sections 7 and 7.1, http://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf

requirements in light of the changing resource mix as well as extreme weather events and what market mechanisms will help ensure we have sufficient supply to address reliability needs.

2. Several panelists at the technical conference suggested that greater use of probabilistic approaches could provide a more robust approach to accounting for extreme weather. Would incorporating probabilistic methods into local transmission planning and/or regional transmission planning/cost allocation processes allow public utility transmission providers to more effectively assess low probability/high impact events and common mode failures? If so, should such practices be incorporated into public utility transmission providers' local transmission planning and/or regional transmission planning/cost allocation processes? What, if any, jurisdictional tariff changes would be necessary to incorporate these practices into existing transmission planning and cost allocation processes? Similarly, should such practices be incorporated into any resource adequacy assessments carried out under FERC-jurisdictional tariff provisions?

The CAISO transmission planning process uses a deterministic approach with multiple sensitivities and variable inputs and assumptions to account for low probability/high impact events. The CAISO transmission planning process reflects NERC and WECC planning standards, which require mitigation based on defined contingency analyses. The CAISO supplements the NERC and WECC planning standards with its own CAISO transmission planning standards, *i.e.,* the CAISO Planning Standards. The CAISO Planning Standards go beyond the NERC and WECC requirements by requiring mitigation for non-consequential load drop in high density urban load areas.[6] In these assessments, the CAISO conducts a risk assessment of various factors, including the topology of the network and impacts of extreme weather events.

---

[6] CAISO Planning Standards, Section 6.

The CAISO considers low probability/high impact events and identifies transmission expansion that may be necessary. The CAISO does not believe requiring a probabilistic analysis in the transmission planning process is necessary or beneficial at this time. Effective probabilistic analysis will reflect historical data. The rapid rate of change associated with climate change and the severity of weather events may soon offer sufficient historical data to support undertaking probabilistic analyses, but the CAISO does not believe sufficient consensus exists among affected stakeholders at this time to utilize probabilistic tools in the transmission planning process. At this time, the CAISO recommends using and adjusting its current deterministic analysis approach to account for climate change risks.

3. At the technical conference, panelists noted the importance of coordinating transfers across the seams between Regional Transmission Organizations/Independent System Operators (RTOs/ISOs) and non-RTO/ISO areas to both reduce costs and improve the resilience of the transmission grid during extreme weather events. How do RTO/ISO and non-RTO/ISO transmission providers manage congestion at system seams? What are the benefits and drawbacks of the current management regime, from the perspectives of cost, resource participation, and ability to maximize reliability and other benefits of transmission service? Can more cost-effective congestion management at the border between RTOs/ISOs and neighboring non-RTO/ISO transmission providers be facilitated through new *pro forma* Open Access Transmission Tariff (OATT) provisions? If so, how could the *pro forma* OATT be modified to achieve this enhanced coordination? For example, could existing *pro forma* OATT section 33.2 (Transmission Constraints), which permits a transmission provider to use redispatch to maintain reliability during transmission constraints, be modified to enhance coordination with a neighboring RTO/ISO during such redispatch? Are there any other potential modifications to the *pro forma* OATT that might facilitate cost-effective congestion management at the border between RTOs/ISOs and neighboring non-RTO/ISO transmission providers? If so, please describe them in as much detail as possible. If such modifications were made to the *pro forma* OATT, could they also help improve coordination between RTOs/ISOs and non-jurisdictional entities through their inclusion in the reciprocity tariffs that are voluntarily filed by some non-jurisdictional entities? What challenges would any such modifications need to address?

The CAISO manages congestion on its interties with neighboring balancing authority areas by modeling both scheduling and energy flow-based constraints in its markets. The scheduling constraints address seams with pro forma OATT-based neighboring balancing authority areas. They ensure transmission schedules over the CAISO interties do not exceed neighboring balancing authority areas' point-to-point transmission scheduling limits on their side of an intertie. The CAISO market models loop flow based on estimations and modeling of generation, load, and transfers between balancing authority areas throughout the Western Interconnection. The CAISO markets maintain both schedules and energy flows within transmission constraints through dispatch based on economic energy bids. The Western Electricity Coordinating Council also has procedures to mitigate loop flows if they overload key transmission paths.

Coordination across seams remains critical to minimize the impact of extreme weather events across the Western region. Increased transparency between balancing areas into resources' availability, assumptions on imports/exports (and sources of the energy), and operational redispatch options will help balancing authorities better prepare for these extreme weather events. In addition to bi-lateral coordination, the CAISO and neighboring balancing authority areas have reduced seams issues through fostering participation in the Western Energy Imbalance Market (EIM). The CAISO intends to work with stakeholders to explore whether it can leverage this platform to better address extreme weather events as well as whether it can extend a day ahead market platform to EIM entities. These efforts may offer additional redispatch opportunities across RTO/ISO and non-RTO/ISO seams to address extreme weather events.

4. RTOs/ISOs currently have differing levels of authority to approve or recall outages· Can generation and transmission outage scheduling practices be improved? For example, should RTOs/ISOs have greater authority to deny generation and transmission outage requests, such as having the ability to deny such a request based on estimated economic impact, as ISO New England currently has? Similarly, should transmission owners be given an incentive to schedule transmission outages more efficiently by making transmission owners responsible for uplift they cause from outages, as the New York Independent System Operator currently does? Would such changes help system operators better prepare for or respond to extreme weather events?

Climate change and extreme weather events have increased the frequency and unpredictability of generation and transmission outages. In light of the impacts to electric infrastructure, the CAISO expects generation and transmission scheduling practices could improve. For example, the need for planned maintenances to mitigate the effects or impacts of climate change or extreme weather events could inform outage coordination processes. The CAISO has authority to deny planned outages based on reliability needs and can restrict maintenance operations during stressed grid conditions. Of course, the CAISO's ability to recall infrastructure on outage back into service depends on the status of work underway.

Exercising authority to deny generation and transmission outage requests based on estimated economic impacts of an outage would require the CAISO to develop the analytical tools necessary to assess the economic impact, as well as the trigger for when it might deny an outage. More important than expanding the authority of RTOs/ISOs (or any transmission provider) to deny an outage, the Commission should consider what incentives exist for asset owners to harden and upgrade their facilities to reduce the likelihood that extreme weather events will induce outages. The NYISO rule that assesses uplift charges to transmission owners based on the impact of their outages arguably creates such an incentive. In making it costlier to take outages, such a rule could, however, create a perverse incentive for transmission operators to delay needed maintenance. As with nearly all market rule changes, the CAISO believes the Commission should allow each ISO/RTO to consider, in consultation with its stakeholders, how best to address the market and operational challenges created by climate change and extreme weather events.

5. Transmission topology optimization (also sometimes known as transmission switching) involves dynamically modifying transmission topology as a component of determining optimal day-ahead and real-time energy market solutions. Should RTOs/ISOs be required to incorporate transmission switching or transmission topology optimization in their day-ahead and real-time energy markets? Could the adoption of such optimization approaches both reduce costs and improve the resilience of the transmission grid?

The CAISO periodically directs transmission switching to eliminate an estimated overload on a transmission facility. This work occurs based on study, analysis and coordination with all impacted transmission owners. The CAISO, however, does not support a general directive for RTOs/ISOs to incorporate transmission switching or transmission topology optimization into their day-ahead and real-time energy markets. Any such effort would require significant planning and design work and should occur only after RTOs/ISOs have had an opportunity to assess in which cases transmission switching may result in economic or reliability benefits. The CAISO refers to its March 21, 2021 comments filed in Commission docket number RM20-16: *Managing Transmission Line Ratings.*

The optimization of the transmission system's topology can occur through changes to both transmission element ratings and network impedance. Transmission providers can adjust element ratings based upon forecasted ambient conditions such as temperature and wind speed. Transmission providers can also adjust the topology of the transmission system, and its underlying impedance, to shift anticipated flows and protectively mitigate expected pre and post contingency overloads. These adjustments can occur through both strategic switching and using remedial action schemes. Incorporating more dynamic transmission switching or topology changes into day-ahead and real-time markets comes with trade-offs relating to market efficiency, price convergence and reliable operations.

The CAISO acknowledges that dynamic or temperature adjusted line ratings can increase transmission capacity in a market operations horizon. Transmission planning and longer term operations planning studies typically assume a more conservative and stressed system condition. This assumption ensures feasibility for any operating condition within the time horizon under review. By the time the day-ahead or real time market is run, the market operator may have significantly better forecast data; potentially with expected ambient conditions being less severe than initially assumed. This in turn may allow for an increase in transmission capacity. However, changes to transmission ratings between the different market runs can create price divergence between the day ahead and real-time markets.

Transmission switching has the potential to relieve expected transmission congestion, however, these actions also have market operations implications. The CAISO's market optimization does not run all credible contingencies. Rather, through its operations planning analysis of forecasted conditions, topology and pending outages, the CAISO selects a limited subset of contingencies to run in its market optimization. Transmission switching between the time period when this analysis is complete and the market optimization run may require significant additional analysis to ensure the optimization accounts for the correct contingencies. Accordingly, the different topologies that result from optimized switching will dramatically increase the market optimization solution time due to the increased power flow and shift factor calculations necessary to ensure system security under each potential topology.

6. Panelists at the technical conference suggested that current requirements for system performance under extreme weather scenarios may need to evolve. Should the transmission planning requirements established under North American Electric Reliability Corporation (NERC) reliability standard TPL-001-4/5 be modified to better assess and mitigate the risk of extreme weather events and associated common mode failures? Should any additional changes be considered to the NERC Reliability Standards to address the risk of extreme weather events?

From the CAISO's perspective, the current framework in NERC Reliability Standard TPL-001 to address extreme events may not serve as the best means to assess the threat and risk of extreme weather events and associated common mode failures. Instead, the CAISO believes a more robust assessment of these threats and risks can occur through scenarios analyses. Reliability standards should ensure planning authorities complete these analyses and can use them to identify needed transmission expansions. However, the standards themselves should not specify the extreme events underlying the analysis. Incorporating individual extreme events in the Reliability Standard may create compliance obligations that do not make sense for certain planning authorities based on the particular weather events they may face or unnecessarily limit the scope of scenarios analyses that planning authorities would otherwise perform.

7. Multiple panelists at the conference emphasized the need to establish a requirement for interregional transmission planning and improve existing interregional cost allocation methods to prepare for extreme weather events. How can the existing requirement to have an interregional transmission coordination (not planning) and cost allocation process be modified to better account for the benefits that interregional transmission facilities provide during extreme weather events? Would defining a set of uniform transmission benefit metrics that can be used across regions in the interregional transmission coordination and cost allocation processes help interregional transmission projects come to fruition? If so, please propose such metrics in as much detail as possible.

The CAISO acknowledges that there are opportunities to improve interregional coordination, but mandating interregional planning poses challenges and may not be the best approach to facilitate the development of interregional transmission. The Commission must be mindful of three very important considerations (among others) that can affect interregional transmission development.

First, states, not the Commission, oversee resource procurement. If states direct their procurement efforts elsewhere or do not support a specific interregional project, the results can be highly problematic. Failure to align transmission development and resource procurement can cause overbuilding, stranded costs, and potentially jeopardize obtaining needed state siting approvals. It is critical that transmission development align with resource development/procurement. Mandating interregional transmission planning may not be the most effective or efficient means of aligning the two.

Second, an interregional transmission project may not be the more efficient or cost-effective transmission solution for a region (or may not be needed at all by a region or a state in the region). There can be legitimate differences among regions and among states in a region. Those differences can be much greater when expanding from regional transmission planning to interregional transmission planning. For example, states may have different resource priorities for achieving their policy objectives or maintaining reliability. For some, it may be more efficient or cost-effective to develop remote in-state resources or distributed energy resources. Others may prefer a resource mix that includes a portfolio of out-of-state resources. Some states may have a robust transmission system, others may not. If a region does not find a need for a specific interregional project in its regional transmission planning process, customers in that region should not be required to pay for the costs of the project.

Accordingly, the Commission should retain the requirement that an interregional project must first be selected in each neighboring region's transmission planning process. Absent such a requirement, certain parties might seek to pursue an interregional transmission facility that arguably provides some benefits to a neighboring region, but which the region does not need to meet its requirements (or that does not constitute the more efficient or cost-effective means of meeting the neighboring regions' transmission needs), and then attempt to pass on the costs of the project to others in order to defray the cost impact on customers in the region where the line is needed. This is akin to involuntary cost allocation, which is unreasonable and inappropriate. State buy-in is critical to enable efficient and cost-effective resource procurement and transmission development and timely siting authorizations.[7] Interregional planning can

[7] If an interregional project requires siting approvals from a state that does not support the project or believe the project is needed, the viability of the project becomes questionable.

cover an extremely vast area and involve a large number of states and transmission providers (many of which have no interaction with each other and never have).

Third, the predetermined, formulaic cost allocation methodologies arising from compliance with Order No. 1000 are a barrier to interregional transmission project development because they create the risk of unintended and inappropriate outcomes. This is particularly problematic when different regions have different benefit metrics. Today, there can be a mismatch of the approaches regions utilize to count transmission project benefits. Dissimilar benefit calculation methodologies among neighboring regions can cause one region to bear an unfairly disproportionate share of the costs of an interregional project because it calculated certain benefits that another region(s) did not consider in its evaluation.

Aligning the benefit metrics among regions might improve interregional coordination, but it would not resolve all potential cost allocation issues. For example, assume a scenario where three regions desire to share the capacity of a new transmission line equally to meet needs identified in their regions. Assume further that all three regions utilize an identical benefits calculation, *e.g.*, the avoided cost of the regional transmission project that would be built in lieu of the interregional project to meet the region's transmission need. Because the cost of the avoided transmission line in each region will vary, the *ex ante* cost allocation formula will cause each region to bear a different share of the costs of the interregional transmission line even though each region receives an equal share of the capacity in the line (and only needs that equal share). *Ex ante* cost allocation schemes that can cause a party to bear costs disproportionate to the capacity it needs from a new project (and will receive in the new project) are problematic and a deterrent to collaborating on interregional projects. Cost allocation should align with the proportionate share of capacity each region has in the interregional transmission project.

Based on the CAISO's experience, interregional transmission development is best accomplished by motivated transmission providers and states working together on agreed-to projects, with negotiated capacity sharing and cost allocation schemes. On the other hand, *ex ante* formulaic cost allocation methodologies and different benefit formulas among regions are a deterrent to interregional collaboration. The Commission should encourage transmission providers and neighboring states to identify mutually beneficial transmission solutions and allow them to negotiate fair and workable capacity and cost-sharing arrangements. The Commission's recent *Policy Statement on State Voluntary Agreements to Plan and Pay for Transmission Facilities*[8] is a positive step in that direction.

The Commission might consider the following enhancements for interregional coordination:

- To facilitate greater collaboration among states and transmission providers, the Commission might consider formally incorporating into the interregional coordination process a forum for states and transmission providers to identify potential resource development zones and potential transmission paths (and possibly even transmission projects). This would encourage developers to submit potential projects that meet actual, identified interregional transmission needs, as opposed to submitting projects they desire to pursue and then waiting for the regions to determine if there is a need for such projects.

- The Commission should consider adopting a cost allocation framework that allocates costs based on the amount of capacity a particular state/transmission provider needs (and will have) from an interregional project, as opposed to allocating costs based on regional benefit

8 175 FERC ¶ 61,225 (2021).

calculations. This will ensure all regions pay an equal share for the capacity they receive.

- The Commission could require regions to submit a report every two years regarding the specific interregional activities they have undertaken and are undertaking. Regions could update these reports biennially, *i.e.,* every two years.

- Finally, the Commission should promote increased interregional coordination by identifying and resolving any regional barriers through the Joint Federal-State Task Force on Electric Transmission.[9]

A more collaborative and targeted approach to interregional coordination can accommodate state clean energy goals because it allows states and transmission providers to align transmission development with state-preferred resource portfolios and resource development in preferred renewable resource areas. This approach will mitigate the stranded cost risk. It will also support more timely (and more certain) siting authorizations because the states will already have prioritized such transmission. It will provide greater certainty to load serving entities that regulatory authorities will approve their resource procurement plans and recovery of the of transmission costs incurred to effectuate such procurement. Absent strong state buy-in for an interregional transmission project, the stranded cost (and overbuilding) risk and the risk of not obtaining necessary siting authorizations increases greatly.

9 *Joint Federal-State Task Force on Electric Transmission,* 175 FERC ¶ 61,224 (2021).

8. Would having a target level of interregional transfer capacity help facilitate more effective development of interregional transmission projects? Should minimum amounts of interregional transmission transfer capability be required or encouraged as a way to improve the resilience of the power system? If so, how should such minimums be determined (e.g., a stated MW or percentage of load basis), and how specifically should such minimum requirements be implemented (e.g., NERC reliability standards or new tariff requirements)?

Resilience is not a clearly defined concept and, unlike the national reliability standards, there are no generally applicable Commission or NERC-approved resilience standards. Furthermore, there can be significant differences among regions for purposes of assessing and achieving resilience. Stated differently, different regions may have different resilience needs. The needs, circumstances, and conditions that exist in each region are unique and can vary significantly, as regions face different risks, threats, and operational challenges. They can have vastly different resource mixes and load curves, fuel supply options, and policy choices. Resilience should account for regional differences, and entities in each region should have the flexibility to determine what capabilities are needed to maintain resilience based on the specific circumstances in their region. For example, the CAISO Planning Standards specify certain resilience-related planning criteria (*e.g*., extreme event) that allow the CAISO to plan for transmission facilities in certain conditions that go beyond the NERC Reliability Standards. The CAISO's experience highlights the need to consider the unique characteristics of each region in addressing resilience. In contrast, requiring a specified level of interregional transmission capacity in a vacuum without considering specific regional circumstances seems arbitrary. It has no direct relation to actual regional reliability, economic, public policy, or resilience needs or regional operations and circumstances.

9. Multiple panelists at the conference suggested that the current reliance on the 1 day in 10-year Loss of Load Expectation is outmoded. Are there alternative resource adequacy planning approaches that could be more robust alternatives to the use of the 1 day in 10-year Loss of Load Expectation standard? Please describe such alternatives, including describing whether such alternatives have been used either in the United States or elsewhere.

In the context of resource planning studies, the CAISO utilizes a 1 day in 10 year loss of load expectation. The CAISO provides these studies into the CPUC's integrated resource planning processes, which in turn help define transmission expansion needs. These studies also support what level of generating capacity the CAISO needs in transmission constrained areas.

With the increase in availability limited resources and the increased frequency of extreme heat events, the CAISO is working with its stakeholders and state authorities to refine how the resource adequacy programs administered by local regulatory authorities in its balancing authority area account for extreme events to ensure that sufficient supply is available to meet expected demand and reserves during all hours of the operating day. Local regulatory authorities and planning authorities may need to reconsider risks associated with resource planning, including parameters such as extreme heat or drought impacting electric demand and availability of resources. These type of risks merit local consideration. As such, the inputs and assumptions to resource adequacy programs, including load forecasts, planning reserve margins and counting rules may be more critical than modifying the 1 day in 10 year loss of load expectation.

III. Conclusion

The CAISO supports the Commission's effort to facilitate a dialog to identify how each region can best address the risk to electric grid reliability associated with climate change and extreme weather events. The CAISO requests the Commission consider the CAISO's comment in connection with this effort.

Respectfully submitted,

/s/ Andrew Ulmer

Roger E. Collanton
General Counsel
Anthony Ivancovich,
Deputy General Counsel, Regulatory
Andrew Ulmer
Assistant General Counsel
Jordan Pinjuv
Senior Counsel
David Zlotlow
Senior Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, California 95630
(916) 608-7209
(916) 608-7222 (fax)
aulmer@caiso.com

Dated: September 27, 2021

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon the parties listed on the official service lists in the above referenced proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010)

Dated at Folsom California this 27th day of September, 2021.

Martha Sedgley
Martha Sedgley