
Market Launch: It's getting real

When I left FERC staff and came to WPTF, I was excited because it appeared to me that the West was ready to move toward regional integration of its market. The Mountain West market extension of SPP was about to launch with a few utilities around the interface between WECC and the Eastern Interconnect. Cool. The CAISO operation of a real-time market was entering its fourth year and growing to incorporate much of remaining WECC. If California could figure out its governance to make it safe for out of state transmission to be turned over to CAISO, it was thought a big Western RTO was within reach.

Mountain West died in April 2018 due to a last-minute withdrawal of Public Service Colorado (PSCo). California tried twice to get legislation that would result in an independent CAISO board free political influence. These were disappointing events but the need to more easily move generation and share resources over a large area was still seen as urgent. Enter the idea of a “day-ahead” market that would allow for something like an RTO dispatch but without any changes in operational control of transmission and the continuance of each utility tariff while operating under another market tariff. First CAISO came up with the idea but then SPP came with its own version of this incremental approach to a regional market.

It's been four years of competing meetings between CAISO's engagement on a day-ahead design and SPP's “Markets +.” Hundreds of hours of meetings, stakeholder engagements, drafts of revised implementation tariffs, protests and comments on FERC filings with a growing faction of adherent market participants of each platform. Discussions on seams, where would this utility go and how would seams – not only between the two markets but within markets and associated utility tariffs – be handled. Each platform raced to work out details on a market design that wasn't quite an RTO but was hopefully an improvement on contract path based bilateral trading.

Now, we're about to begin the first phase of one of these new markets. On May 1, PacifiCorp will begin operation of the CAISO “Extended Day-Ahead Market” or “EDAM”. For the first time, there will be a “day-ahead” LMP in the West outside of California. The Portland General System is supposed to follow this fall. SPP's Market Plus begins in fall of 2027 with Arizona Public Service, Tucson Electric Power, Salt River Project, Powerex and PSCo.

Let's be clear: This incremental step short of a regional dispatch with its multiple Balancing Areas (BAs) and maintaining traditional firm transmission uses should be an improvement over the status quo transmission use. But it has never been done in real life before. There will be things that need changing as we gain experience. Hopefully this will incent market participants to agree to take the next logical step; an RTO-like organization with a single tariff.

Courage folks! Here we go.

Scott Miller

Contents

- Wider West Committee (2WC) Report [Page 2](#)
- CAISO Committee Report [Page 4](#)
- CPUC Committee Report [Page 7](#)
- California Legislative Committee Report [Page 10](#)
- Carbon and Clean Energy Committee Report [Page 12](#)

Save the Date

WPTF Summer Meeting

August 12 - 14, 2026
Coeur D'Alene, Idaho

Registration Opening Soon

WIDER WEST COMMITTEE (2WC)

Caitlin Liotiris

Caitlin Liotiris is a Principal at Energy Strategies, where she has more than 15 years of experience supporting a wide range of clients in the electricity sector, including supporting market analyses and transmission development activities. Caitlin coordinates WPTF's Wider West Committee (2WC), which engages on market, policy, reliability and technical developments in the "wider West," generally outside of California. The 2WC is active in advocating for broader western energy markets, which includes active participation in the NorthWest Power Pool's Western Resource Adequacy Program (WRAP), and in coordination with the CAISO Committee on the EIM and EDAM, especially as they relate to tariff provisions and impacts outside of the CAISO. Caitlin brings her analytical, regulatory, policy and strategic expertise to bear in supporting 2WC members by providing information and advocacy on a wide variety of issues affecting the electricity industry.

Déjà vu All Over Again – Problems with Firm Transmission Rights Arise in Markets+, Despite the Market Design Enabling Transmission Opt-Outs

One of the fundamental challenges in developing day-ahead markets in the West is reconciling two very different frameworks which are intended to overlay on top of one another: 1) the existing Open Access Transmission Tariff (OATT) structure, which is built around bilateral transactions and firm transmission rights; and 2) the centralized dispatch and locational marginal prices (LMPs) in organized markets. Western stakeholders have long understood that the success of the proposed day-ahead market constructs depends on finding a way for these two worlds to co-exist.

That challenge was front and center during the development of EDAM, especially when – around this time last year – significant concerns arose about the ability for firm transmission rights to be exercised in EDAM without exposing transactions to new and unmanageable congestion risk. As discussed in this column last year, the initial implementation proposals for EDAM, including the tariff provisions proposed by the first EDAM Entity (PacifiCorp) would not have adequately respected existing transmission rights and the contractual arrangements built upon them.

Since then, the most critical concerns were addressed through CAISO's efforts to quickly propose and implement an alternative solution to congestion revenue rights that allows customers to utilize firm transmission rights in EDAM with "balanced self-schedules." As a result, the most fundamental concerns about the ability to continue to transact on OATT rights when EDAM is implemented have been resolved, at least for now.¹

Unfortunately, it appears we may once again be revisiting the same fundamental problem in Markets+ despite stakeholders developing provision for "transmission opt-outs" within the market design which were intended to address the issue. During the development of Markets+, stakeholders recognized early on that transmission customers in the West may need to continue to rely on firm transmission rights reserved under OATTs even after the implementation of Markets+. To address this, the Markets+ tariff includes provisions allowing transmission customers to designate certain, eligible transmission capacity as "opted-out" of the market's transfer capability calculations.

¹ CAISO has recently kicked off "Phase 2" of the EDAM Congestion Revenue Allocation Enhancement design and will consider changes to the congestion revenue allocation approach going forward.

Under this framework, transmission capacity that is opted-out is not considered available for market-optimized transfers within Markets+. The general expectation during policy development was that such opted-out transmission could continue to be used for bilateral transactions much as it is today – effectively insulating those transactions from market pricing and congestion exposure within the Markets+ footprint and permitting continued use of OATT rights. The core policy objective for transmission opt-outs appeared clear: provide a mechanism that allows existing transmission rights to continue to be used outside of the market optimization when necessary.

While individual Transmission Service Providers (TSPs) retain discretion over how transmission opt-outs are permitted – retaining the ability to implement more stringent rules around opt-outs than are in the Markets+ tariff – it is important that, when transmission opt-outs are permitted, they are treated appropriately by Markets+ settlement in a manner that effectively allows OATT rights to continue to be utilized.

But, unfortunately, recent discussions with SPP staff suggest that the practical implementation of transmission opt-outs may diverge significantly from what many stakeholders believed the policy would accomplish. In particular, SPP staff has

indicated that – even when transmission is opted-out of market optimization – transactions using that transmission would still be settled within the Markets+ pricing framework. Under this interpretation, a generator delivering energy across opted-out transmission would still be paid the LMP at its injection point and charged the LMP at the withdrawal point. In other words, the transaction would remain exposed to congestion and losses between the source and sink, even though the underlying transmission capacity was removed from the market optimization. Moreover, because the transmission is opted-out of the market dispatch process, it would not receive congestion revenue allocations. This combination could leave transactions exposed to congestion risk without the offsetting financial mechanisms that normally accompany market participation, and effectively defeats the functionality that transmission opt-outs were designed to provide. It also raises an obvious question: if transmission opt-outs do not actually insulate transactions from market pricing exposure, what purpose do they serve?

The situation begins to look very similar to the issues encountered in EDAM. At their core, both debates reflect the same structural tension. Western electricity markets are attempting to overlay centralized day-

ahead market optimization on top of a transmission system that was designed for bilateral contracting supported by firm transmission rights and on which many existing contracts and delivery requirements are built. The Markets+ discussions now underway suggest that the industry will – once again – have to try to reconcile use of OATT rights within a day-ahead market construct.

SPP has acknowledged the disconnect between stakeholder expectations and its current interpretation of transmission opt-outs. And, after WPTF raised the issue during recent Markets+ stakeholder calls, SPP's team has agreed to hold an educational session to further explore the issue and determine whether additional action is needed in the Markets+ stakeholder process. WPTF's Wider West Committee will be deeply engaged in these discussions, aiming to move a solution forward that will provide the benefits stakeholders thought they were getting when they designed the transmission opt-out concept.

As these conversations unfold, the dynamic feels strikingly familiar to the issues that arose with EDAM last year. Once again, stakeholders are working to ensure that a day-ahead market design can coexist with the firm transmission rights that underpin so much of the West's bilateral trading framework.

Déjà vu, indeed.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR (CAISO) COMMITTEE

Carrie Bentley

Carrie Bentley is the co-founder and CEO of Gridwell Consulting and has over a decade experience in the energy industry across the ISO/RTO markets. Ms. Bentley currently provides analysis and strategic support on “all things California ISO,” including transmission, interconnection, capacity, storage assets, and the energy markets. Prior to becoming a consultant, Ms. Bentley most recently had been acting as a lead market design and regulatory policy developer at the CAISO, leading design and stakeholder initiatives in critical areas such as flexible ramping, resource adequacy, and renewable integration. Prior to the CAISO, Ms. Bentley was a consultant for GDS Associates, an engineering and economics consulting firm where she specialized in power supply contracting, natural gas hedging, and energy market design for a large range of clients in ERCOT, PJM, MISO, and SPP.

WPTF CAISO Committee Quarterly Report Day-Ahead Market Enhancements Move Toward Implementation

While much of the regional discussion in Western electricity markets focused on expansion initiatives such as the EDAM), significant changes are also occurring within the CAISO market itself. Several of these changes will take effect on May 1 as part of the Day-Ahead Market Enhancements (DAME) initiative, one of the most substantial evolutions of the CAISO day-ahead market since the introduction of the nodal market.

Although regionalization remains an important strategic development, DAME will materially change the CAISO market’s daily operations.

At a high level, DAME is designed to better align the day-ahead market with real-time operating needs as the resource mix becomes increasingly dominated by renewable generation. The initiative aims to reduce the need for out-of-market operator actions by ensuring that the day-ahead market more effectively anticipates real-time uncertainty.

During the policy development process, WPTF raised several concerns. These concerns were not directed at the objective of preparing the system for increased renewable variability. Rather, WPTF cautioned that the proposal risked moving forward before several foundational

design issues had been fully resolved.

WPTF questioned whether the proposed products had been sufficiently justified, particularly the introduction of both upward and downward Imbalance Reserve and Reliability Capacity products. WPTF also expressed concern that the market design was becoming unnecessarily complex relative to the operational problems it was intended to address.

Additional concerns focused on whether the proposal would produce rational and transparent prices, whether storage resources could feasibly support the new obligations, and whether implementation risks were being understated given CAISO’s experience implementing nodal procurement for the Flexible Ramping Product.

As implementation approaches, these concerns remain relevant. The central question is no longer whether DAME should move forward conceptually, but whether the final design will produce workable outcomes in practice.

A Market Designed for Uncertainty

The most visible change introduced by DAME is the addition of Imbalance Reserve products to the Integrated Forward Market (IFM). Imbalance Reserve Up (IRU) and Imbalance Reserve Down (IRD) will be co-optimized with energy and

ancillary services in the IFM. Their purpose is to procure flexible capacity in advance that can respond if renewable generation or load deviate from forecasts in real time. Current simulations estimate the level of requirement may be significant, most notably for the CAISO balancing authority area (up to 4,000 MW IRU and 5,000 MW IRD in some hours).

Historically, the day-ahead market primarily scheduled energy and ancillary services, with much of the remaining uncertainty managed later in real-time or with operator actions. As uncertainty has increased, this structure has become less efficient. Imbalance reserves are intended to procure flexibility earlier, allowing the market to enter real-time better prepared for deviations.

During policy development, WPTF raised concerns about the assumptions used to establish and distribute the requirements, which are calculated hourly using statistical estimates of historical uncertainty and distributed proportionally based on size of resource rather than level of uncertainty. The design relies on deployment scenarios that assume a large share of uncertainty materializes and evaluates congestion impacts under those conditions. The concern was not with nodal pricing itself, but with the deployment-scenario methodology, which could produce prices reflecting modeled

congestion and uncertainty assumptions rather than actual operating conditions.

Another operational feature introduced with DAME is the use of envelope constraints for storage resources. These constraints establish upper and lower bounds on a battery's state of charge to ensure sufficient energy remains available to support imbalance reserve obligations if deployed in real time.

Storage feasibility was a major concern raised by WPTF during the policy process. Storage resources operate under physical state-of-charge limits and may simultaneously receive awards for energy, ancillary services, and flexibility products. If these interactions are not modeled correctly, the day-ahead market could produce physically infeasible schedules. Envelope constraints are CAISO's attempt to mitigate this risk.

Reliability Capacity Products

In addition to imbalance reserve products in the IFM, DAME introduces Reliability Capacity Up (RCU) and Reliability Capacity Down (RCD) products in the Residual Unit Commitment (RUC) process. These products address a different operational objective. While imbalance reserves are intended to manage forecast uncertainty, reliability capacity ensures that sufficient physical resources are committed to meet expected real-time demand.

If the IFM clears insufficient supply relative to forecasted load, the RUC process will procure RCU capacity. If excess supply exists, the market may procure RCD capacity to preserve downward flexibility.

Reliability capacity bids will be capped at \$250/MWh. Resources that submit energy offers in the IFM must also submit corresponding RCU bids up to the quantity of their economic energy offers. Resource adequacy resources, in particular, will be required to participate to ensure that capacity commitments translate into operational availability.

A notable operational change associated with this design is the expanded role of storage resources. Storage will participate in the RUC process for the first time. Resource adequacy storage resources are required to submit RUC bids, and if bids are not submitted, they may be inserted into the market.

This represents a significant shift in how storage participates in day-ahead reliability commitments. Storage resources can now support reliability-backed day-ahead positions, including high-priority exports. At the same time, this expanded role reinforces the importance of accurately modeling storage state-of-charge constraints within the market design.

Looking Ahead

As the implementation date approaches, market participants are preparing for changes that will affect bidding strategies, price formation, and operational planning. DAME represents a meaningful attempt to adapt CAISO's market design to a system characterized by higher renewable penetration and greater forecast uncertainty.

However, the concerns raised by WPTF during the policy development process remain important as the market transitions to implementation. Questions persist regarding whether imbalance reserve requirements are appropriately calibrated, whether the deployment-scenario framework will produce credible price signals, and whether storage resources can reliably support the expanded set of market obligations.

Regional market expansion may continue to dominate long-term discussions in the West, but DAME is the most immediate structural change facing CAISO market participants today. The May 1 implementation marks the beginning of a materially different day-ahead market framework, one that will require careful monitoring as the market gains operational experience with the new design.

CPUC COMMITTEE

Gregg Klatt

Gregg Klatt coordinates the CPUC Committee. Gregg is a practicing attorney with over 20 years of energy industry experience. With a practice focused on state and federal regulation of the electric power and natural gas industries, Gregg has represented clients in numerous rulemaking proceedings before the CPUC, CEC and CARB. He advises energy companies concerning regulatory requirements affecting their product and service offerings. He represents generators, marketers and retail suppliers in licensing, compliance and enforcement matters. And he provides regulatory counsel in energy-related transactional matters, including procurement contracting, resource development and repower projects, asset dispositions, and related financing arrangements. Gregg received his J.D. from UC Berkeley's School of Law and has a B.A. in History from the University of San Francisco.

TFW¹ You Were Promised RCPPP But Get Another MTR Procurement Order Instead...

In Remember back in September, when we were eagerly anticipating a proposed decision (PD) on CPUC staff's Reliable and Clean Power Procurement Program (RCPPP) proposal? And what we got instead was a completely separate staff proposal for "interim" reliability procurement, along the lines of the Commission previous Mid-Term Reliability (MTR) procurement directives? You know, the ad hoc procurement directives that RCPPP is supposed to replace? Well, the latter staff proposal—not RCPPP!—has now been adopted, as part of a [PD](#) approved at the CPUC's February 26 voting meeting. But still no sign of the RCPPP PD. Le sigh.

Anyway, here are the key provisions of the Commission's newest MTR procurement directive:

- CPUC-jurisdictional load-serving entities (LSEs)—i.e., the three big investor-owned electric utilities (IOUs), community choice aggregators (CCAs), and electric service providers (ESPs)—must procure a total of 6 GW of new qualifying resources, with 2 GW to come online by June 1, 2030, another 2 GW by June 1, 2031, and the final 2 GW by June 1, 2032. Mind you, that's 6 GW of net qualifying capacity (NQC), not installed capacity, so effectively the procurement order is for much more than just 6 GW of new capacity.

- At least 25% of each LSE's allocation (about 1.5 GW on a system-wide basis) must come from clean firm resources ($\geq 80\%$ capacity factor, not use-limited) or long-duration energy storage (≥ 8 -hour discharge). This sub-requirement, which is akin to the long-lead-time (LLT) resources requirement from the original MTR order, was adopted in lieu of a proposed 50% cap on the use of storage resources, which would have made compliance nearly impossible. That's a big win for LSEs and developers. But it does add a layer of complexity to fulfilling the new requirements that LSEs would probably have been happy to do without.
- The resources must be storage resources and/or zero-emitting/RPS-eligible resources (fossil-fuel projects are still out), and must represent incremental capacity, with commercial online dates after January 1, 2020. Both the storage and generation components of hybrid resources are eligible to count toward the new requirements (provided the applicable component is a "new" resource). And procurement contracts must have terms of at least ten years, with deliveries scheduled to begin by the applicable procurement tranche deadline. This all tracks with the

¹ "That feeling when" for those of you who are not social media savvy, or don't have access to a Gen Z consultant. Direct all other questions regarding slang in this article to Gregg Klatt.

previous MTR orders, as does the decision's extension of the three-year flexible compliance window established in 2024 for the original MTR procurement requirements. And any excess procurement under the prior MTR orders can count toward the new targets.

The Commission is allocating responsibility for the new requirements using each LSE's share of system managed peak load (based on the 2024 IEPR forecast), with individual LSE targets specified in an [attachment](#) to the decision. Resource accreditation and compliance assessments for the new requirements will rely on effective load-carrying capability (ELCC) based counting (with ELCC values still forthcoming for later years), with net-CONE penalties for any procurement shortfalls. Besides the extended three-year compliance window noted above, LSEs also can seek penalty waivers based upon a showing of good-faith compliance efforts.

What does the Commission's latest procurement directive mean for stakeholders?

For CPUC-jurisdictional LSEs, it means updating their upcoming IRP filings and launching new RFPs for long-term contracts. In addition to facing increased competition for the most viable candidate resources, the challenge for LSEs will be weaving the new targets into their procurement strategies and carrying the resulting

obligations on their balance-sheets, all while navigating an ocean of uncertainty around data-center load growth, amid stormy forward markets, under an ever-shifting constellation of procurement-related rules and regulations. *Good times, good times.*

For developers with projects sitting in the CAISO queue, it means they now have a clear, date-certain procurement signal for those projects that have a reasonable chance of being brought online in the 2030–2032 window. It also moves high-ELCC resources—especially long-duration storage and clean firm options like geothermal—to the front of the procurement line for their LSE counterparties. The challenge for developers will not only be securing long-term PPAs but also getting enough steel in the ground in time to secure the federal tax credits upon which their project's very viability is premised. That means securing an adequate and dependable supply of critical project materials from still-fragile supply chains, all while what appears to be an intentional effort on the part of the current administration to effect major changes in the political and economic systems that underpinned global trade for decades. In any event, projects of all stripes with strong interconnection positions and shovel-ready attributes just became significantly more bankable.

The effects of the new order will extend well beyond California's borders into the broader WECC. An additional 6 GW of storage and clean energy resources will strengthen regional reliability at a time when loads are rising across the West. It will also feed directly into CAISO's transmission planning process (more on that below), potentially unlocking new paths for out-of-state resources and easing congestion on key interties. For market participants in EDAM, Markets+, or WRAP, the added California supply will shift day-ahead optimization, RA market dynamics, and inertia price signals—creating both new export opportunities and altered economics for marketers and generators throughout the Western Interconnection. So, for you out-of-state participants in California's energy and RA markets, your plan should be:

1. CPUC issues interim procurement order
2. California LSEs procure 6 GW of incremental NQC
3. ???
4. Profit!!!

Given the significant workload imposed on CPUC staff in connection with the new procurement order (updating models, running additional studies, and supporting LSE compliance), it is entirely possible the Commission will leave RCPPP on the back burner for now, or even put it back on the shelf for a couple of years.

If that happens, then all the effort that stakeholders have put into developing the RCPMP will have come to naught. *Lol. Lmao, even.*

Recommended Portfolios for the 2026-2027 TPP

In addition to the new procurement requirements, the aforesaid decision adopts IRP-driven resource portfolios that, pursuant to a longstanding MOU, the Commission will transmit to CAISO for analysis in the latter's biennial transmission planning process (i.e., in the CAISO's 2026-27 TPP cycle). The adopted base-case portfolio meets a 25 million metric ton GHG emissions target for 2035, while achieving <0.1 LOLE in key study years, with the selected resources being mapped to specific busbars.² The base case incorporates previous procured MTR resources and builds on the 2025-26 TPP base case with modest adjustments (e.g., extending offshore wind timelines by a couple years to reflect current commercial realities). Solar build rates in the base case remain several multiples of recent historical levels, to meet both reliability and clean-energy goals.

Unlike in previous years, when the Commission adopted sensitivity cases that were focused on exploring the limits of potential policy-driven transmission needs, the Commission's recommended sensitivity portfolio is intended as an exercise in prudent contingency planning. Thus, in addition to the base case, the decision adopts

a Limited-Wind (or Low-Wind) scenario that sharply constrains both in-state and out-of-state wind development to test what transmission would be needed if recent federal policy shifts or permitting challenges cause wind buildout to slow significantly. The result is a portfolio with even greater solar and storage additions being needed to still hit the applicable GHG target. The sensitivity portfolio is also more expensive than the base case. But the Commission views it as a useful "what-if" exercise to identify alternative transmission solutions that could be repurposed if wind buildout stalls.

For transmission developers and other queue participants, the base case and sensitivity portfolios represent a roadmap and an RPG map, respectively. The base case signals where the Commission expects most new investments will be made and where the new resources will be located; the sensitivity case may help highlight backup transmission needs if a lot of wind projects get nuked. Only the former will drive CAISO's reliability and policy-driven study and result in board-approved transmission projects, potentially accelerating approval of new lines or upgrades that benefit projects across the CAISO and wider WECC footprint. That latter will be fun to play with but should almost certainly not be used as the basis for any major asset allocation decisions. *fr fr*

Taken together, the new procurement requirements and transmitted portfolios shore up mid-term reliability and give the CAISO the modeling inputs needed to keep transmission ahead of the curve. Whether the upcoming round of new procurements fully closes the feared reliability gap remains to be seen—heck, I would not be surprised if this is not the last ad hoc procurement directive we'll be seeing come out of the Commission in the next five to ten years. But at least LSEs, developers, and Western market participants now have clearer marching orders for the next several years.

² *Busbar mapping results are posted here: [Assumptions for the 2026-2027 TPP](#).*

CALIFORNIA LEGISLATIVE COMMITTEE

Jesus Arredondo

WPTF Legislative Committee consultant is Jesus Arredondo.

Jesus is the principal and founder of Advantage Government Consulting LLC and has over 19 years of experience in media and government relations, including concentrated experience in energy policy. Prior to launching Advantage Consulting, Jesus worked as a senior advisor for two major public relations firms in the United States and Mexico. Jesus also served as a policy advisor to a major California transmission project, principal advisor on an education effort in California concerning natural gas and on a national education campaign concerning the FERC's push for standard market design. Before launching Advantage Consulting, Jesus was a bilingual spokesman for two California governors and served five years as director of regulatory and government affairs for a fortune 250 independent power producer and two years at the California Power Exchange, where he served as director of corporate communications.

Energy Legislation for 2026 Session Begins to Take Shape

With Gov. Gavin Newsom clearly distracted with running for the White House in 2028, California lawmakers have put forward several energy proposals for this legislative year that are beginning to take shape.

As Legislative leaders continue to emphasize affordability, a number of measures are expected to focus on reducing utility costs or preventing further increases. Sen. Scott Wiener has signaled interest in making it easier for local governments to move away from PG&E. Assemblymember Tasha Boerner Horvath has proposed mandating a 25 percent reduction in investor-owned utility bills. Senator Josh Becker has also indicated plans to introduce a placeholder bill addressing utility spending and profits.

Another major issue looming over the Legislature is the future of Diablo Canyon, California's last remaining nuclear power plant. Sen. John Laird, whose district includes 2.2 GW reactor facility, has suggested lawmakers consider extending the plant's operations beyond 2030 as the state projects continued growth in electricity demand.

Separately, Gov. Gavin Newsom announced a proposal to launch a \$200 million electric vehicle rebate program aimed at boosting EV sales following President Donald Trump's cancellation of the \$7,500 federal tax credit.

Gasoline prices and fuel supply are also expected to receive increased scrutiny as the Valero Benicia refinery and the Phillips 66 Los Angeles Basin facilities are scheduled to close this spring. That closure is likely to intensify legislative attention on affordability issues affecting both electric bills and prices at the pump. Meanwhile, Sen. Weiner is proposing to allow the state to be able to sue oil companies to pay for insurance losses and higher prices following fires, floods and other disasters.

Finally, lawmakers are beginning to introduce bills addressing data centers. Senator Sasha Renee Perez is proposing a ban on diesel backup generators for all data centers. Senator Steve Padilla is proposing that exemptions in the California Environmental Quality Act do not apply to data centers and would require the CPUC to establish a special tariff to protect ratepayers from the transmission costs associated with serving large data centers while still meeting the state's climate goals.

Focus on Data Centers and Power Costs

The Legislature will be actively debating the future of artificial intelligence (AI) and data centers in the balance of this session, with a particular focus on their enormous power requirements and environmental impacts.

Senator Padilla is leading the charge with two bills this session, SB 886 and SB 887, targeting data center development and oversight. His opposition to a proposed data center in Imperial County highlights growing legislative concern about the energy and water resources required by these facilities, as well as their potential impact on local communities. Critical in the discussion for the legislature has been the cost of the infrastructure needed to serve data centers and how to keep that cost from impacting regular consumers.

As we have reported to the Legislative Committee, the California Energy Commission (CEC) recently adopted an updated energy demand forecast for 2025-2045, incorporating revised estimates for power usage from both data centers and electric vehicles (EVs). According to the CEC's projections, data centers alone are expected to require approximately 4,700 megawatts (MW) of electricity. This figure underscores the scale of infrastructure needed to support California's booming tech sector and the rapid expansion of cloud and AI computing. While there is excitement over the growth that translates to jobs, there is consternation by the Legislature as they try to ensure energy affordability. This theme will continue to drive the policy discussions.

What About EVs as Cost Drivers for Energy?

While Sen. Padilla is not focused on the EV impact, we anticipate that other members will notice this aspect of the driving growth and potential energy infrastructure impact – and costs. As noted by the CEC, the surprising, anticipated energy demand from electric vehicles will far surpass that of data centers. The CEC estimates that EVs will require over 8,000 MW of electricity by 2045, more than double the demand from data centers.

This surge is fueled by California's aggressive push toward transportation electrification and its efforts to exceed clean car goals, with more than 2.5 million EVs sold since 2010 – a fact that Gov. Newsom has celebrated. The scale of this transition is seemingly unprecedented and presents both challenges and opportunities for the state's power grid.

But there's a wrinkle. According to the California Department of Motor Vehicles (DMV), as of late 2023 and early 2024 data, California has roughly 1.25 million (1,256,646) light-duty, all-electric vehicles (BEVs) currently registered – that's half of what the state has been telling the press. Note that according to DMV, California reports

approximately 35.98 million (35,983,261) registered vehicles in the state.

As the legislature weighs new regulations for AI and data center development, and as energy planners adapt to the explosive growth in EVs, California faces a critical moment. Lawmakers, regulators, and industry leaders must work together to ensure that the state's infrastructure can meet the demands of a rapidly evolving digital and clean energy landscape, while balancing environmental stewardship and community interests. The huge assumption is that both data centers and EVs will exhibit the projected growth that is anticipated.

But, as we always caution this time of year, we are far too early in the process to get terribly excited about anything. Moreover, this is California. What else might happen between now and the end of the session to motivate legislative action on energy policy? It remains to be seen how the mentioned proposals will evolve as legislative committees begin their reviews in March.

Final Note: As of this report, the WPTF Legislative Committee is tracking 125 potential new bills. Stay tuned!

CARBON AND CLEAN ENERGY COMMITTEE

Clare Breidenich

Clare Breidenich coordinates WPTF's Carbon and Clean Energy Committee. In this role, Clare has been actively involved in the development of California's cap and trade program since its inception and has particular expertise on issues related to the treatment of electricity imports under the program and the interactions of the carbon market and the markets operated by the CAISO. Clare also represents WPTF on matters related to carbon and clean energy policies in other western states.

Prior to joining WPTF, Clare worked on international climate issues at the Environmental Protection Agency, the US Department of State and the United Nations Framework Convention on Climate Change Secretariat. Clare has extensive knowledge of the technical and policy options for greenhouse gas mitigation, including market mechanisms, and methodologies and protocols for estimation, reporting and verification of greenhouse gas emissions and reductions. She has served on the Washington Governor's Climate Action Team, the Washington Carbon and Electricity Markets Workgroup and on a National Academy of Sciences' Committee on monitoring of greenhouse gas emissions. Clare is a graduate of the University of Michigan and has a Master of Public Affairs and a Master of Science in Environmental Science from Indiana University School of Public and Environmental Affairs.

Trump Administration's Hostility to Climate Policies Continues

Throughout the past year, I have reported on the ongoing efforts of the Trump administration to target the state climate policies, including the cap-and-trade programs in California and Washington. (The administration also has its sights set on elimination of existing federal policies, namely vehicle emission standards, and prevention of any future policies, but that discussion is beyond the scope of this newsletter.)

The latest shot came on February 12th, when Trump's Environmental Protection Agency (EPA) formally rescinded the "Endangerment Finding". The Endangerment Finding codified the 2009 determination by the EPA under the Obama administration that greenhouse gas emissions (GHGs) threaten public health and welfare. This determination followed the landmark Supreme Court case *Massachusetts v. EPA* (2007), in which the Court ruled that greenhouse gases qualify as "air pollutants" under the Clean Air Act and that the EPA must determine whether such emissions pose a danger to public health or welfare. The ruling was the basis for various federal GHG programs, notably the Clean Power Plan, which was nullified by the Supreme Court, and Vehicle GHG emission standards.

While state climate programs, such as the California and Washington cap-and-trade programs, derive their authority from state laws rather

than federal policy, rescission of the Endangerment Finding helps set the Trump administration up to argue that state climate programs are incompatible with Federal Policy (and thus unconstitutional). Most observers agree that a Federal legal challenge to the state cap-and-trade programs is a given – it's just a question of when. Without commenting on the legal outcome of a federal challenge, one thing is clear – it would likely take years to play out in the courts. If the challenge is still moving through the legal system and a more climate-friendly President is elected in 2028, the incoming administration could simply drop the case.

Nonetheless, Linkage is Likely

In the meantime, Washington, California and Quebec are moving forward with plans to link their respective cap-and-trade programs as of January 2027. On Tuesday the Washington Department of Ecology released and requested comments on the draft [linkage agreement](#) for the three jurisdictions.

This notice doesn't come a moment too soon. The last Washington allowance cleared at \$70.86, triggering an Allowance Price Containment Reserve (APCR) Sale in February at which 3,641,334 APCR allowances were sold at the Tier 1 price of \$60.43. These results do nothing to alleviate concerns that Washington prices may blow through the \$80 program price cap. In contrast, the last California allowance on February 18th cleared

at the WCI auction floor of \$27.94. Although this result is surprising, given the California Air Resources Board's (CARB) intention to tighten the pre-2030 program caps, it suggests that the fundamentals of the linked California-Quebec programs are quite different than Washington's, due in large part to the much greater size of the California-Quebec market. There are thus reasons to believe that linkage will put downward pressure on Washington's prices, but if the linkage does not take effect until Washington's second compliance period, linkage may not come in time to help Washington avoid blowing through the \$80 price ceiling. Hence Ecology's urgency.

The linkage agreement comes against the backdrop of both Washington and California revising their program rules. The most notable development is the most recent release by CARB of proposed amendments to the cap-and-trade program (now called cap-and-invest, as in Washington) and mandatory reporting regulation. Recall that these amendments have been long expected but put on hold pending the September authorization by the California Legislature to extend the program.

While there are numerous smaller changes, the amendments that will be of most interest to readers of this newsletter are the changes to the program caps, and new provisions addressing carbon capture, storage and utilization, and energy storage systems:

- Allowance caps for the years 2027 – 2030 have been cumulatively reduced by 118 million tons relative to current caps. The caps for the entire 2027- 2045 period reduced by 1 billion tons relative to the trajectory in the current regulation. These changes were proposed in in the last Scoping Plan and reflect GHG inventory updates and statutory direction.
- CARB has proposed a new section to address future provisions to reduce compliance obligations associated with carbon that is captured and stored or utilized (CCUS). CCUS would essentially be treated as an offset, subject to a 100-year permanence standard, under protocols and calculation methods to be developed. Unfortunately, the new language seems to limit the applicability of any future CCUS protocol to CO2 suppliers. WPTF will seek to have this broadened to cover other emissions sources, including electricity generation.
- CARB has also included new reporting provisions for imported electricity that has passed through energy storage systems as specified electricity. These provisions would require imports through grid-charged storage to report using the default unspecified emission factor. Alternatively, the importer could

claim specified electricity for a portion or all of the charging electricity, provided it complies with other requirements for specified sources. An energy storage system may also choose to register as a specified source to have a resource-specific emission factor calculated. For an ESS that elects a resource-specific emission factor, the emission factor will be based on the MWh and associated emissions of any specified primary generation and grid energy used to charge the resource in the previous year, divided by the discharged MWh. (This calculation implicitly includes the loss factor). Once calculated, the ESS must use the emission factor for reporting of import transactions in the following year. This framework should support different business and operation models for energy storage. However, because it would require an importer of energy from an energy storage system to use a static emission factor for reporting these transactions in the following year, it may undermine the value and incentive to storage operator of charging when both energy prices and emissions are relatively low.

The Washington Department of Ecology is expected to follow CARB's lead when it releases the next version of its own rule sometime this spring.