QUARTERLY REPORT

March 2019

Introduction

Let's see…what has happened since the last Quarterly Report? Something big happened, I know it. Something…oh, yeah. The biggest counter-party in the West was downgraded, and then filed for bankruptcy. But don't worry, there are no possible effects on the rest of us. Except perhaps that some additional risk will get priced into the market for anything that produces power or relates to it. Except on the possible value of a contract anyone might have with PG&E. Oh, and perhaps on the value of any renewable power contract with any of the investor-owned utilities (IOUs) that was required to meet the Renewable Portfolio Standard (RPS). Don't worry. The situation is very contained. Besides, the Legislature and the Governor are on this. We're good.

Now, how about other things? The thing that is really getting my attention is the stall on moving toward broader markets in the West. The California Independent System Operator (CAISO) has done important work in getting the Energy Imbalance Market (EIM) up and running, but the move to "regionalize" has stagnated—the California Legislature has been unable to change the CAISO governance so that utilities from other states will feel comfortable turning over their transmission to CAISO to get the full benefits of a regional market. The workaround has been to "extend" a revised day-ahead market to the EIM Entities and then—supposedly—one gets most of the benefits of a regional market. Except, how is it OK to have the utilities continue to manage the transmission? How does that not make the exercise of "unilateral market power" a real danger?

Why shouldn't the EIM utilities just put out a request for proposals for a market administrator? They've got the governance (EIM board), they've got size, they've operated an incremental market already, and the Federal Energy Regulatory Commission (FERC) would require a joint operating agreement so that selling into California or buying from it would be almost seamless. CAISO could be one of the parties that could bid on it, along with Southwest Power Pool (SPP), PJM, or whoever. The quickening pace of renewables integration should make it important to get going.

Well, it seems as if many things are happening. Better read the rest of the Quarterly Report!

Scott Miller

Contents

Save the Date

2019 Summer General Meeting
Board Meeting July 24
General Meeting July 25-26
The Edgewood Resort
Stateline, Nevada

2020 Winter General Meeting
February 20-21
Park Hyatt Aviara Resort
Carlsbad, California

Check the WPTF website for all the details

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.

A New Governor, But Old Problems Shape 2019

Three days after being inaugurated as the 40th governor of the State of California, Gavin Newsom offered his first budget, which, at $209 billion, is $8 billion more than former Governor Brown's last budget. Newsom's major point, which he repeatedly stressed, was that even with the state treasury flush with billions of extra tax dollars, he's being careful about making long-term commitments that could backfire in a recession. Instead, his budget devotes the vast majority of those dollars to one-time spending or paying down debt, including unfunded pension liabilities. Newsom called it "budget resiliency," noting that even a moderate recession could slash revenues by $70-plus billion over three years, overwhelming the state's "rainy day fund" and other reserves. In effect, he's continuing Brown's cautious approach to expensive commitments, while offering one-time appropriations and start-up funds for the ambitious expansion of health care, early childhood services, and other big-ticket programs he advocates.

Between the inauguration and the middle of May, the Governor and the Legislature will continue to trade ideas and make arguments about spending. The "supermajority" Democratic Legislature will seek to spend as much of the surplus as possible, and Newsom's challenge will be to rein it in.

A surplus is a relatively nice problem to have. In the category of not-so-nice problems: PG&E. On January 29, 2019, PG&E filed for bankruptcy for the second time in 18 years. The company's filing came on the heels of the devastating wildfires that ravaged the utility's service territory in 2017 and 2018 and which PG&E is now accused of causing. With over $30 billion in potential liabilities mounting, the crushing financial exposure left the company with very few alternatives. The Board of Directors voted on January 28 to go ahead with a Chapter 11 bankruptcy filing in federal court.

With CEO Geisha Williams abruptly resigning days before, interim CEO John R. Simon offered the following: "We … intend to work together with our customers, employees and other stakeholders to create a more sustainable foundation for the delivery of safe, reliable and affordable service in the years ahead. To be clear, we have heard the calls for change and we are determined to take action throughout this process to build the energy system our customers want and deserve."

In inheriting the massive problem, Governor Gavin Newsom simply stated: “PG&E today filed for reorganization in federal bankruptcy court. That was PG&E’s choice but it does not change my focus, which remains protecting the best interests of the people of California. My administration will continue working to ensure that Californians have access to safe, reliable and affordable service, that victims and employees are treated fairly, and that California continues to make forward progress on our climate change goals.”

Left in the wake of the bankruptcy is significant legislative uncertainty. What can the Legislature actually do? What can the Governor and CPUC actually do? For now, the San Bruno federal court case will continue to play out—and will likely guide how the Legislature and Governor view and respond to the bankruptcy fallout.

A day after the PG&E filing, U.S. District Judge William Alsup declared that the utility violated the terms of its probation for the 2010 San Bruno gas pipeline explosion. Judge Alsup had opened the hearing before a packed courtroom by comparing PG&E to a drug dealer who violates probation by committing a different crime. He noted that PG&E equipment was involved in starting 17 recent wildfires. The judge spoke very sharply to the PG&E attorneys, stating, “Does a judge turn a blind eye and let PG&E continue what you’re doing, let you keep killing people? There is one clear pattern here: PG&E is starting these fires. Global warming is not starting these fires. You’ve got to be on your absolute best behavior—no more crimes.”

The judge strongly suggested he’d ratchet up safety requirements on the utility’s probation, saying he’s considering such simple restrictions as requiring that PG&E not start another fire. Alsup has also threatened to order the company to make a thorough inspection of its electricity grid and complete a wide-ranging vegetation management plan ahead of the fire season. He said trees or limbs falling into PG&E equipment posed the biggest menace. PG&E wrote in a court filing that such a move by the judge would necessitate a $75–150 billion investment and the hiring of 650,000 workers. Alsup was not amused and threatened to sanction PG&E further.

So, while we have a new governor, the old problems are shaping the new year. The legislative year is barely getting going, but most of the legislation (with a few minor exceptions) is all about dealing with PG&E, the other investor-owned utilities, and future fires and fire liability.

In fact, the first hearing of the year will belong to the Senate Energy Committee, which will focus on PG&E’s reorganization.

Of the nearly 2,600 bills that have been introduced in 2019, only a few energy bills are worth mentioning for now: Senate Bill 772 (Bradford) would require CAISO to procure 2,000–4,000 MWs of long-duration bulk energy storage. Assembly Bill 915 (Mayes) would move the RPS from the current 60% to 80% by December 31, 2038. Assembly Bill 56 (Garcia) would establish a central statewide entity to procure electricity for all end-use retail customers in the state. Assembly Bill 235 (Mayes) would create the California Wildfire Catastrophe Fund Authority. Senate Bill 549 (Hill) would subject PG&E electric rates to legislative approval. Finally, Senate Bill 550 (Hill) would put parameters around approval in change of PG&E structure. There is no word yet on proposals to address “inverse condemnation,” but we anticipate that this idea may become legislation. The session is just getting started, and concludes on September 13, 2019.

CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC) COMMITTEE

Dan Douglass

Dan Douglass has directed WPTF's legal efforts since helping to cofound WPTF with Gary Ackerman in 1998. On behalf of WPTF, he has been extremely active at the California Public Utilities Commission and assists Ellen Wolfe, Caitlin Liotiris, and Carrie Bentley with WPTF matters at the Federal Energy Regulatory Commission (FERC).

His firm, Douglass & Liddell, specializes exclusively in energy law issues, providing regulatory and transactional counsel to generators, suppliers, and end-users in the electricity and natural gas markets. This work has included the formation and representation of several influential regulatory advocacy organizations in addition to WPTF.

Prior to Douglass & Liddell, Dan was a partner with the national firm of Arter & Hadden, where he headed the firm's California energy practice; he previously was General Counsel of LG&E Power and President of Cook Inlet Energy Supply. Dan also spent 15 years at Southern California Gas Company and its affiliates and worked on several international and domestic gas supply and storage issues during that time.

What Energy Matters Are Getting the CPUC's Attention?

Its's Fast Times at Van Ness High (with apologies to Amy Heckerling, Sean Penn, and Jennifer Jason Leigh)! This quarter's update does not focus on a single topic, as per usual. Instead, it provides a brief update on the energy matters that are garnering the most attention at the CPUC currently.

Resource Adequacy. RA has been a hot topic for years, but the past year has been particularly busy. It culminated in the 5-0 approval at the February 21 CPUC meeting of a hastily revised, last-minute, proposed decision that (a) adopted three-year forward RA requirements, (b) deferred action on a central buyer while giving parties six months to collaboratively come up with a proposal, and (c) adopted reporting directives for Energy Division designed to increase transparency in the RA process.

At the CPUC meeting, it was made clear that, if parties are unable to reach an agreement on central buyer issues, assigned Commissioner Randolph plans to issue her own proposed decision in the fourth quarter. It was also apparent that the chances of ever getting a centralized capacity market approved are somewhere between slim and none (and ole Slim just had a heart attack). Also, President Picker reprised one of his favorite diatribes, citing the 11 local RA waivers granted last year, and proclaiming that he was "kind of cranky" about this and that he will "insist" that the CPUC approve no waivers for load-serving entities (LSEs) in the coming summer. As he put it (no joke) it will be, "hard time for RA crime!" See Greg Klatt's RA report nearby for information on what's next for RA and planned WPTF efforts.

PG&E Bankruptcy. The PG&E bankruptcy has, of course, consumed attention at the CPUC since the utility first announced its intention to file. A primary focus of observers has been the topic of what the CPUC might do if the utility attempts to reject in bankruptcy any of its higher-priced, early renewable contracts.

The process is complicated by several issues, such as the fact that the utility is a convicted felon on parole, FERC and the bankruptcy court are embroiled in a jurisdictional dispute, and the Governor has instituted what Karol Denniston, our speaker at the recent WPTF general meeting, described as a "SWAT team" to address issues related to the bankruptcy. Matters are further complicated by the fact that U.S. District Court Judge Alsup, who is assigned to enforcing the utility's probation, is entirely dissatisfied with the utility's behavior, asking recently how many more people he should allow the utility to kill.

For the CPUC, renewable contract rejection is a paramount topic—and one on which President Picker has made clear his position. Namely, the contracts are sacrosanct and the

CPUC opposes any rejection effort by PG&E.

It was notable that the CPUC recently issued a proposed decision concerning a petition to modify a 2006 decision regarding the Otay Mesa power plant. Even though there were several procedural reasons to dismiss the petition summarily, Administrative Law Judge Fitch took the time to address the merits, saying that, "it is important for this Commission to affirm its commitment to the sanctity of contracts, especially given the need for additional new electricity infrastructure in the state to meet our long-term clean energy goals." As well as being a resounding endorsement of the sanctity of contract, the discussion has clear PG&E bankruptcy implications.

Nevertheless, it is likely PG&E will approach renewable contract counterparties seeking renegotiation as a prelude to rejection if a modification cannot be achieved. Rejection would leave counterparties with an unsecured claim, while a successful renegotiation would result in a secured status. The CPUC may well be forced to approve renegotiated contracts as part of a "grand deal." Some portion of PG&E's wildfire costs will likely end up being socialized in rates. A way to create headroom for those rate increases would be to have a concomitant rate reduction due to renegotiated long-term renewable contracts. The CPUC may well have to hold its nose and go along, with urging from Bankruptcy Court Judge Montali.

Finally, the entire bankruptcy process may ultimately lead to a breakup of the utility and the establishment of separate electric and gas units that are independently regulated by the CPUC. A likely accompanying feature would be an explicit safety protocol to govern ongoing operations of each. The bankruptcy will be a multiyear process and there are many twists and turns to expect down the road.

Wildfires. On February 6, the utilities filed their wildfire plans in response to Senate Bill 901, which requires state utilities to prepare detailed plans for combating wildfire risk. Each of the major IOUs submitted plans that feature additional weather stations and modeling tools, increased vegetation management, and more frequent, proactive power shut-offs.

On February 19, a very well-attended prehearing conference was held in the de-energization proceeding. President Picker's opening remarks focused on the fact that 7 of the 10 most destructive fires in California history have occurred in the past five years, owing to climate change. The de-energization proceeding will focus on rules for determining when de-energization can occur, notification to affected end users, and protocols for collaborating with safety services and essential use facilities.

PCIA. The Power Charge Indifference Adjustment (PCIA) was adopted by the CPUC to ensure that when electric customers of the IOUs depart from IOU service and receive their electricity from a non-IOU provider, they remain responsible for procurement costs previously incurred on their behalf by the IOUs.

Recently issued D.18-10-019 retained the same basic structure for the PCIA calculation, rejecting both IOU and Community Choice Aggregator (CCA) proposals for a broader modification. It also approved caps and floors to the PCIA. A Phase 2 working group will address remaining open issues, such as revising the Green and Capacity benchmarks; allowing direct access and CCA customers to negotiate a prepayment for future PCIA obligations (i.e., a buyout); and considering proposals for portfolio optimization, cost reduction, and voluntary allocation and auctions.

Direct Access Expansion. Finally, the CPUC is subject to a legislative mandate to act by June 1 to implement Senate Bill 237, which provides for a 4,000 gigawatt-hour increase to the current cap on direct access. Yet to date, the only response from the CPUC has been "we're working on it." Further, by June 1 of 2020, the CPUC is to send a report to the Legislature on how direct access can be reopened for all nonresidential customers. Given the speed at which it has responded to the first deadline, it's questionable whether the 2020 deadline will be met.

RESOURCE ADEQUACY (RA) COMMITTEE

Greg Klatt

Greg Klatt coordinates the [Resource Adequacy Committee]. Greg is a practicing attorney with over 20 years of energy industry experience. His practice focuses on state and federal regulation of the electric power and natural gas industries. He has represented clients in numerous ratemaking and rulemaking proceedings before the CPUC. He regularly advises energy companies regarding regulatory requirements applicable to their product and service offerings. He represents marketers and retailers in CPUC licensing, compliance and enforcement matters. He also commonly acts as regulatory counsel in energy-related transactional matters, including procurement contracting, resource development projects, repower projects, major asset acquisitions and related financing arrangements.

Greg received his J.D. from UC Berkeley's School of Law (Boalt Hall). He graduated magna cum laude with a B.A. in History from the University of San Francisco and is a lifetime member of the Alpha Sigma Nu honor society.

The Resource Adequacy Committee is Up and Running

WPTF's RA Committee was created in October 2018 to provide focused coverage of RA-related regulatory proceedings at the CPUC. WPTF has long advocated for improvements to the RA program, notching up several successes over the years. But there has never been a dedicated forum where WPTF general members can discuss RA policy and help develop WPTF's policy positions. The RA Committee was formed to provide such a forum, while also providing committee members with timely and incisive updates about major developments in the CPUC's RA rulemakings and related proceedings.

Going forward, the RA Committee will serve as the vehicle through which WPTF members shape WPTF's advocacy on RA issues before the CPUC, with near-term objectives including the adoption of multiyear requirements for all RA products and the creation of a centralized capacity market.

RA Policy Statement

Last summer, WPTF's board approved an initial RA policy statement to guide WPTF's advocacy efforts. Below are the key objectives of WPTF's RA policy:

- The establishment of three-year forward procurement requirements for system, local, and flexible RA.
- The unbundling of flexible capacity into a standalone RA product.
- Allocation of multiyear RA requirements in the same manner that year-ahead requirements are currently allocated.
- CAISO-administered capacity auctions that account for all supply necessary to meet forward RA procurement requirements.
- The ability for LSEs to self-supply, enter into bilateral contracts, and/or rely on the CAISO-administered capacity auctions to fulfill their forward RA procurement obligations.

Track 2 Proposals

In testimony submitted in Track 2 of the CPUC's current RA rulemaking proceeding (R.17-09-020), WPTF presented several proposals consistent with its RA policy statement:

- Three-year forward procurement requirements should be adopted for local, system, and flexible RA, with explicit compliance targets.
- The CAISO should assume the role of administering a centralized clearing capacity market to satisfy the "central buyer" concept discussed in the CPUC's Track 1 decision (D.18-06-030).
- Flexible RA should be unbundled from system and local RA, and the CPUC should consider the CAISO's proposal to develop a separate flexible deliverability study.
- Effective load carrying capacity (ELCC) estimates for RA

resources should, to the greatest extent possible, reflect the impact of behind-the-meter solar PV.

The Centralized Procurement Gordian Knot

The biggest issues in Track 2 are centralized procurement and multiyear RA requirements. In a proposed decision issued last September, the CPUC proposed to adopt three-year forward procurement requirements for local RA only, with the IOUs (PG&E, SCE, and SDG&E) each designated to act as the "central buyer" for all local RA in their respective service territories. The proposed decision was met with vehement opposition from nearly all sides.

In a series of letters addressed to the CPUC commissioners, key players in the RA arena recommended major changes to the proposed decision, many of which were mutually incompatible. Then, on February 15, a revised proposed decision was issued that adopts three-year local RA requirements but defers a decision on the designation of a central buyer for those requirements. The revised proposed decision was approved on a 5-0 vote at the CPUC's February 21 voting meeting.

Understandably gun-shy after the poor reception of its original proposed decision, the CPUC's Track 2 decision defers most of the implementation issues associated with centralized procurement of multiyear local RA requirements, directing the parties to hold at least three workshops over the next six months "to identify workable central buyer and central procurement structure proposals."

The first workshop will be held in April (date TBD). Each workshop will be facilitated by a different market representative (i.e., a representative of the IOUs, Electric Service Providers, and CCAs) or by a facilitator chosen by same. The Track 2 decision also directs the parties to designate a responsible party or parties to prepare an informal workshop report outlining the parties' recommendations.

In addition to deciding on the identity of the central buyer(s), the Track 2 decision directs the parties to develop "workable implementation solutions" for central procurement of multiyear local RA, including: the scope of central buyer procurement (i.e., full, residual, or some combination), a cost allocation mechanism (e.g., how costs will be tracked and recovered), oversight mechanisms, other procurement details (e.g., resources to be included, selection criteria), market power mitigation tools, and any necessary modifications to the RA timeline.

In other words, the CPUC metaphorically threw up its hand and said, "Since you didn't like what we did, you go figure it out!" We'll see how that works out.

Next on the Menu

Besides directing the parties in Track 3 to hash out the remaining details from its Track 2 decision, the CPUC has called for Track 3 proposals to be filed on March 4.

In addition to the adoption of local RA requirements for 2020–2022 and flexible RA requirements for 2020, the issues specifically scoped for Track 3 include revisions to the RA load forecast methodology, consideration of how storage and combined resources should be counted for RA credit, and refinements to the third-party demand-response qualifying capacity methodology. The Track 3 scoping ruling also provides for "[c] onsideration of other modifications and refinements to the RA program as identified in proposals by Energy Division or by parties."

A two-day workshop on Track 3 proposals is scheduled for March 12-13. Parties will have the opportunity to submit written comments on "the workshop and all proposals" (including an earlier-filed Energy Division proposal for Effective Load Carrying Capacity reforms) on March 22, with reply comments due March 29.

WIDER WEST COMMITTEE (2WC)

Caitlin Liotiris

Caitlin Liotiris 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, especially the EIM and other regional market expansion opportunities. The 2WC also follows important developments at Peak Reliability and the Western Electricity Coordinating Council. Caitlin has over a decade of experience in energy issues in the West and has spent most of those years actively engaged on market development efforts across the Western Interconnection footprint, including a major role in developing the policies for implementing the EIM. She is skilled in understanding and distilling the interaction of energy policy and energy market dynamics. In addition to her work with WPTF, Caitlin has worked on various energy policy and market related issues throughout the county. Caitlin is currently a member of Peak Reliability's Member Advisory Committee (MAC) and has also co-authored various reports exploring the benefits of proposed transmission facilities in the West.

Without Adequate Independent Oversight, Can Organized Markets Fall Victim to Anti-Competitive Outcomes? An Illustrative Example from the Energy Imbalance Market (EIM) and Implications for the Extended Day-Ahead Market (EDAM)

As someone interested in, and optimistic about, the potential for organized market development in the Western Interconnection, it has been difficult to articulate exactly why I think market proponents should exercise some caution when evaluating extending CAISO's day-ahead market to EIM Entities (a market construct being referred to as "EDAM"). But a recent example of activity in the EIM that appear to foster anti-competitive outcomes has helped illuminate the importance of ***thorough and complete*** independent oversight for organized markets, a feature that is somewhat lacking for certain aspects of the EIM and which may be lacking in the EDAM proposal. As I hope you will see, there are several areas, including tariff oversight, where WPTF members should be vigilant to ensure that EDAM, or any alternative market construct, facilitates the most competitive outcomes possible.

The feasibility of EDAM is currently being assessed by the EIM community (i.e., the organizations that have signed an EIM Entity Agreement). Because I am not participating in the feasibility study, I can speak only to the details I have gathered from public presentations, and it is possible that the construct has changed or is more nuanced than I understand. With that caveat, I understand that EDAM would allow EIM Entities to elect to participate in the CAISO's day-ahead market without actually joining the CAISO as a full Participating Transmission Owner. Thus, EDAM has the allure of offering the benefits of day-ahead unit commitment and dispatch (and associated renewable integration benefits) across a large market footprint potentially covering much of the Western Interconnection, without forcing resolution of some of the issues that proved most controversial in efforts to create a full Independent System Operator (ISO) or Regional Transmission Organization (RTO), such as a joint resource adequacy construct and cost allocation for new transmission infrastructure. EDAM also aims to use a governance structure similar to the EIM Governing Body, thus avoiding the need to change California statue to alter the selection of the CAISO Board of Governors.

Although EDAM appears poised to offer benefits, it would not provide certain types of benefit that are provided by full ISOs/RTOs. Joint transmission planning (generally performed in ISOs/RTOs) is off the table for EDAM, and EDAM's construct, alone, appears unlikely to provide sufficient incentives for more diverse long-term generation procurement over the EDAM footprint (such as the procurement of incremental, regionally diverse renewable resources). Nevertheless, it offers an enticing "next step" in organized market development in the West, with the potential for significant benefits. Thus, its pursuit is exciting for market proponents.

EDAM is modeled, in many ways, after the EIM, but on a larger scale. In the EIM construct, CAISO oversees implementation of the EIM-related portion of its tariff, which governs some of the market, but the EIM Entities retain their transmission tariffs and continue to administer (via their tariffs) many things that influence EIM outcomes, such as transmission use, dedication of transmission, and charging customers for transmission use (or imposing penalties for unreserved use of the transmission system). That appears likely to be the case in EDAM, as EDAM's designers (the EIM community) have stated their intent for EDAM to allow them to retain operational control of their transmission systems and retain their open access transmission tariffs (including the contract path-based sale of term transmission rights through those tariffs). In other words, it appears that EDAM would not require that the utility participants turn over operational control, tariff administration, authority over transmission sales, or responsibility for transmission billing to an independent entity.

With that background on EDAM, let's explore a situation that is currently occurring in the EIM, which helps highlight issues that may be more likely to occur when there is not complete independent oversight of the entire transmission tariff. A third-party generating resource inside an EIM Entity area is seeking to submit economic bids (and be dispatched) in the EIM. Today, the generator makes appropriate transmission reservations for any sales it makes in non-EIM markets. The resource is seeking to bid any remaining generation capacity into the EIM. But the third-party resource has been told, by the EIM Entity/transmission provider, that when the generator is dispatched into the EIM by CAISO, it will be charged punitive "unreserved-use" penalties unless it has reserved, in advance, enough transmission to cover not only its non-EIM sales but also the EIM dispatch from CAISO (a value that is unknown to the generator until the dispatch instruction is received, in close to real time). Unreserved-use penalties are designed to ensure that generators do not use the transmission system without an adequate transmission reservation. To discourage unreserved use of the system, these penalties are generally highly punitive and can be orders of magnitude more than a generator would typically pay for reserved transmission.

The problem with this situation is that the EIM was actually designed to make use of latent transmission capacity on the system. Transmission use in the EIM is supposed to be free, consistent with the EIM's "reciprocity" transmission agreement. Use of transmission for EIM dispatches does not require the prearranged reservation of transmission. According to EIM Entity tariffs and Federal Energy Regulatory Commission (FERC) orders on this topic, transmission charges should not apply to EIM dispatch, and unreserved use penalties are not supposed to be charged for generation dispatched into the EIM. These documents state that unreserved use penalties should apply only to generation in excess of the sum of both a customer's (preexisting) transmission reservation and the amount of its EIM dispatch. Thus, whether intentionally or not, the EIM Entity in this case does not appear to be following the requirements of its own tariff.

That said, this part of the tariff, despite its impact on EIM participation, is not under the authority of the EIM Governing

Body, CAISO, or the Department of Market Monitoring. The generator can certainly make these bodies aware of the issue, but ultimately this part of the tariff is administered by the EIM Entity/transmission provider (with FERC oversight). The EIM Entity, along with most (if not all) other EIM Entities, also happens to have merchant/generation affiliates submitting bids into the EIM and hoping to profit from EIM participation. So, theoretically, EIM Entities may not be incented to facilitate participation by third-party generators, who may be competing with their affiliates. This potential conflict, or appearance of a conflict, raises questions about whether additional independent oversight of this (and perhaps other) aspects of market tariffs would better facilitate competitive market outcomes.

Of course, the generator in this case can initiate a dispute with the EIM Entity or bring the issue to FERC, but that could be expensive and may undermine any expected EIM-related profits for the generator. As it currently stands, the third party is effectively prevented from submitting bids into the EIM, an outcome that is detrimental to competition in the EIM and potentially harmful to end-use customers across the EIM footprint. This outcome would be far less likely to occur, and its resolution swifter, if all the pieces of the tariff that affect the EIM were overseen by a truly independent party, as they are in ISOs and RTOs.

I want to explicitly acknowledge that it is certainly possible that this particular circumstance in the EIM is the result of a mistake or misunderstanding that may be cleared up through additional discussions with the EIM Entity. None-the-less, the example highlights a broader, structural concern with the unique market designs that are being discussed in the West: When processes that affect the market's efficiency and competitiveness are not overseen by a fully independent entity, the potential for anti-competitive outcomes may increase.

The development of EDAM is in the very early stages, and there are still ample opportunities for its design to address the concerns illustrated by this example. I would encourage those working on EDAM design to evaluate methods for providing comprehensive, independent oversight of all of EDAM, but especially those parts of the tariff that affect market outcomes (such as the rules for transmission access, use, and charges). Building in this oversight will be critical to securing the most benefits for consumers.

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.

When It Rains, It Pours

The WPTF California Independent System Operator (CAISO) Committee and the Energy Imbalance Market (EIM) subcommittee have had a whirlwind start to the year. In the first two months of 2019, we delivered at least 12 public comments to CAISO on proposed policy changes, coordinated with CAISO and WPTF members on initial PG&E bankruptcy implications, and waded through countless technical documents to understand EIM resource sufficiency test changes. (Apologies to our members for all the emails.) As expected, CAISO is going full steam ahead with its ambitious three-year plan.

The policy changes being considered range from the mundane but widely applicable across resource types (variable operations and maintenance cost review), to cutting edge and limited in reach (new battery energy storage rules and storage as a transmission asset), to technical and important (local market power mitigation enhancements and new intertie deviation penalties). Of course, overarching these and other ongoing policies are proposals for resource adequacy (RA) reform and day-ahead market enhancements.

Thinking about it all is enough to make anyone's head spin, so this Quarterly Report focuses on the newest, shiniest CAISO proposal—improvements to battery energy storage rules. First, a confession: Until this year, I was a passive observer of any policy related to battery energy storage resources. This was purely practical. As the CAISO Committee consultants, we cover "all things CAISO," and there was so little storage on the CAISO grid, it represented no more than a rounding error in terms of market results. As of 2019, however, things have changed. Battery storage resources are entering the interconnection queue and CAISO energy markets in enough quantity that both development budgets and energy market participants should be extremely interested in following all storage policy initiatives. Companies developing storage projects care how their resources will be optimized (and thus improve revenues) and the entire market should be interested in how storage will impact day-ahead and real-time prices. Storage has the unique ability to suppress both price peaks and valleys, and has the potential to significantly affect ancillary services and flexible market prices.

Step one in understanding how storage will earn revenues and influence market prices is understanding how CAISO uses storage in the energy markets. Storage is optimized under a "Non-Generator Resource" model that enables the CAISO to decide the optimal market intervals at which to charge or discharge the battery. CAISO's Energy Storage and Distributed Energy Resources (ESDER) 4 issue paper proposed that it is reasonable to investigate whether "enhancements to the model are necessary to ensure that the CAISO is optimally using these unique resources to meet the reliability needs of the grid." WPTF believes this is the exact right time to ask that question because only now are market participants gaining enough experience with the model to answer this question.

At the highest level, the impact of storage on market prices can be easily understood. Imagine it is August 2020 and there are 3,000 megawatts (MW) of storage energized on the CAISO grid. In the day-ahead market, during the peak solar generation hours in the middle of the day, simply add 3,000 megawatt hours (MWh) to demand and estimate a clearly less negative price as all the storage on the grid charges. In the peak load hours of the day, do the same thing, but this time add 3,000 MWh (likely lower cost) to the supply, and estimate a reduced peak price. Storage, at its core, is an arbitrage product, and therefore will affect the market differently than if, say, 3,000 MW of additional solar came online.

The day-ahead market is easy to envision because the whole day is optimized at once. Where things get complicated incredibly quickly is when storage is optimized in the real-time market. The real-time market time horizon (the amount of time the optimization "looks across") is much shorter and changes depending on the market run. It could be that, in one market interval, discharge of storage appears optimal, but as time goes on, it would have been better from both a cost minimization and profit maximization standpoint if the CAISO optimization had waited to discharge the resource. This is where active real-time bidding by the storage resource's scheduling coordinator, and perhaps some updated CAISO rules, are most needed.

In ESDER 4, CAISO has proposed to look at both the "impact of the multi-interval optimization" (what is described above) and another technical issue that relates to the challenges of predicting how much energy the battery has left to discharge ("state of charge") when supplying offers to the real-time market. Both of these are challenging issues and have solutions that range from allowing a scheduling coordinator to provide a spread bid, to offering multiple offer stacks that vary based on the resource's actual state of charge at the time of market optimization. In short, there are no easy solutions.

Additionally, it is easy to foresee a situation in which storage is routinely being built in local areas as an alternative to using existing gas plants or transmission resources. This means that the storage resource may have the opportunity to exert local market power; however, CAISO currently exempts all storage resources from local market power mitigation rules. Part of ESDER 4 will be to determine if and how CAISO should mitigate storage resources. Luckily, CAISO has on staff someone who designed battery energy storage mitigation while at the Southwest Power Pool, so this part at least should go smoothly from a policy perspective. I expect it will be much trickier for everyone to update their production cost models and bidding strategies after mitigation rules are in place.

MEXICO COMMITTEE

Rajan Vig

The WPTF Mexico Committee Consultant is Rajan Vig. Rajan started his career in strategy consulting with FTSE 100 companies, working at WPP Group in London before working at private equity firm, Hamilton Bradshaw, where he began his consulting focus on commodities. He moved to Houston in 2014 to found an energy human capital consultancy within Sir Peter Ogden's portfolio, where he oversaw the build-out of commercial energy businesses across oil, gas and renewables into emerging markets across the Americas, specifically Mexico and the Southern Cone. Most recently, Rajan started and ran BioUrja Trading's office in Mexico City, managing the company's implementation across trading and origination in Mexico across fuels, gas and electricity. Rajan has a BA (Hons) in Modern Languages (Spanish & Italian with Portuguese) from the University of Manchester and an MSc in Latin American Studies (Economics & Politics) from Oxford University.

This year has heralded a prodigious change in both Mexican politics and in the conduct of the country's energy sector. Energy has been at the forefront of the new administration's dialogue to the *pueblo mexicano*. Nevertheless, the majority MORENA party has lofty plans but no agenda to execute. We hear long, arduous, inconsistent speeches like those of other socialist government leaders in Latin America. The inconsistencies, especially, may play in our favor: We may not know what to believe after all the speechifying but, quite frankly, neither does MORENA (a recent 180-degree turn on fracking provides a perfect example of MORENA members contradicting each other). It is business as usual whilst the party's "plan" sorts itself out.

AMLO's First Week

At the start of December 2018, in President AMLO's first week in power, he took the bull by the horns and announced the cancellation of the long-term power auctions, even though three previous auctions had been successful. The rating agency Moody's had noted that, because of the three previous auctions, Mexico's renewable energy prices were among the cheapest in the world. The agency added that private investors seeking investment opportunities through the auctions had "added stability to the electricity grid of Mexico through diversification." AMLO's cancellation of the fourth long-term auction has had negative repercussions for Mexico in its electricity sector because it raises doubts about the country's commitment to investments in renewable energy and the future of private funding for new energy projects.

Electricity Plan and "Conspiracy"

AMLO believes that the energy regulatory commission (CRE) has conspired against the national utility called the Federal Electricity Commission (CFE), conducting a "deliberate dismantling" similar to that of Pemex. "They were employees of private individuals, conspiring against the Federal Electricity Commission, a public company," he announced angrily, suggesting that the functions of both the CRE and the national hydrocarbons commission (CNH) would have to be reviewed. He also broadly accused neoliberalism of dismantling the CFE, indicating that politicians wanted to keep the market.

AMLO said that, "with what they left us, we are going to rescue the country," but acknowledged that, in the short term, dependence on the purchase of electric energy could not be reversed. Apparently, AMLO wants to return the CFE to a company that supplies the entire country. He identified CFE's self-sufficiency as an objective, and believes that invigorating hydroelectric assets will provide clean and affordable power to the nation. He proclaimed a plan to make the CFE a strong company that generates power without increasing the price of electricity in Mexico.

Natural Gas Review

AMLO also made the public aware he will be auditing the CFE gas pipeline construction program initiated under the previous two administrations. Manuel Bartlett, the new head of CFE, explained on Twitter that the past administration promoted a network of private gas pipelines and contracted for transportation, with an investment of $15 billion and high interest rates that would have led to a commitment of $70 billion. Bartlett then said that the system is paralyzed by various social problems, inefficiencies, and responsibilities, "without having even contributed a gas molecule."

The AMLO administration zeroed in on pipeline injustice for the CFE—AMLO insisted during Electricity Plan discussions that contracts have been made to favor private gas companies. Even though seven gas pipelines are effectively not online, the CFE is still obliged to spend $21 billion on contracted purchases in the medium term, coming away empty-handed. AMLO went on to say that the administration "…will seek to reach an agreement with the participation of companies. I hope that opening this dialogue with the companies will achieve a renegotiation for the benefit of Mexicans. And we maintain the commitment not to increase in real terms the price of electric power to consumers. We are going to comply, but we want the private sector, national and foreign, to help us, without imposing anything, through conviction."

Pipeline Shutdown

The MORENA government recently made a deeply contentious decision to shut down all fuel pipelines coming into the country. The goal was to stop the *huachicolero*, or fuel thief, issue that has enveloped Mexico for years, with numbers and volumes of thefts increasing rapidly in the past decade. However, the shutdown plan was executed with incredibly poor knowledge of fuel logistics, creating mayhem in the Republic.

Motorists across West and Central Mexico lined up at gas stations for days at the end of January, desperately trying to fill their tanks and get on with their daily lives. The grave effect that fuel shortages have had led many to stay home, closing down businesses temporarily and leaving the population with no choice but to cope. Given that the pipelines are riddled with illegal taps drilled by fuel thieves, the AMLO administration switched to importing fuel by truck rather than pipeline. However, the President soon discovered he had fewer trucks than he needed, and ended up buying 671 new ones in the U.S., at above-market prices.

Conclusion

The Mexico committee has had the opportunity to hear and ruminate over the new President and his ruling party since December 1, and we have the following observations. The way AMLO talks, or perhaps more accurately lectures (in a highly nonacademic fashion), is akin to that of recent leftist politicians of the Chávez and Morales persuasion. His misunderstanding and generic use of "neoliberalism" is concerning and inconsistent—he discusses promoting competition in the market, a core idiosyncrasy in a laissez-faire market. Additionally, his inability to distinguish among commodities points to a lack of core knowledge about the electricity sector. AMLO has an obsession regarding Pemex and enjoys talking about oil, irrespective of his audience or topic. His compounding of oil, gas, and electricity inspires grave concern, as it seems to indicate that his government lacks tact and organization, not to mention any real plan.

CARBON AND CLEAN ENERGY COMMITTEE

Clare Breidenich

Clare Breidenich coordinates [WPTF's Carbon and Clean Energy Committee](). Clare has over 18 years' experience on greenhouse gas regulation and policy. In addition to her work with WPTF, Clare has worked on international climate issues with the Environmental Protection Agency, the Department of State, and the United Nations Framework Convention on Climate Change secretariat. She has also served on the Washington State Governor's Climate Action Team and on a National Academy of Science's Committee on monitoring of greenhouse gas emissions.

Oregon Moves Forward with Cap and Trade...

In January, the Oregon Joint Senate-House Committee on Carbon Reductions introduced House bill (HB) 2020. HB 2020 would establish a multisector greenhouse gas cap-and-trade program, modeled on and intended to link with, California's program. Titled the Oregon Climate Action Program, the bill is widely expected to pass during this legislative session.

The Oregon Climate Action Program would go into effect January 1, 2021. The cap initially would be set based on the average of emissions of covered sectors for the three most recent available data years prior to 2021. Caps would then decline annually at a constant rate to achieve a 45% reduction below 1990 levels in 2035, and 80% reduction by 2050. The program would cover industrial sources of greenhouse gas emissions, electricity generation and imports, natural gas marketers and utilities, and producers and importers of transportation fuels. Non-covered entities can participate in the market, and the program would allow entities in covered sectors that are below the program emission threshold to opt in.

Problematically, the bill would exempt emissions associated with electricity generated in state and exported, and "for which the capital and fuel costs associated with the generation are included in the rates of a multi-state jurisdictional electric company that are charged to the electricity customers in a state other than Oregon." This is apparently directed specifically at PacifiCorp's portion of its Hermiston facility. Because the exemption would undermine the environmental integrity of the program, it could impair linkage to California. It would also be unfair to operators of other generating resources in the state that also export power

The bill places the compliance obligation for electricity imports on Electricity System Managers. An Electricity System Manager is defined as:

> any entity that, as needed, operates or markets electricity generating facilities, or purchases wholesale electricity to manage the load for wholesale or retail electricity customers within a balancing authority area that is at least partially located in Oregon, including but not limited to the following types of entities: a) electric companies, b) electricity service suppliers, c) consumer-owned utilities, d) the Bonneville Power Administration and e) electricity generation and transmission cooperatives.

This definition does not appear to allow for assignment of carbon emissions to EIM Participating Resource Scheduling Coordinators, as in done in California's program. WPTF has requested that the Oregon Carbon Policy Office (CPO) conduct rulemaking to determine how to assign emissions associated with electricity imported into the state via the EIM.

As in California, the bill provides for direct allocation of allowances to IOUs and consumer-owned utilities, as well as natural gas utilities and emission-intensive trade exposed industries. Unlike California's program, the Oregon program does not require that IOUs consign directly allocated allowances to auction, but would enable them to use the allowances for compliance obligations associated with their own generation or purchased electricity. WPTF is seeking inclusion of language to ensure that IOU use of allowances does not competitively disadvantage independent power producers or energy service suppliers.

The bill does not provide much detail on market rules, but directs the CPO to develop these through rulemaking. Covered entities would be able to use offsets for up to 8% of their compliance obligation, of which half must be from projects that provide direct environmental benefits to Oregon.

Allowances that are not directly allocated would be distributed via auction, which would be open to all registered entities and held at least annually. The CPO is directed to develop rules and procedures for auction, including the establishment of an increasing auction price floor, holding limits, and any other measures necessary to "minimize potential for market manipulation and bidder collusion." The CPO is also authorized to engage outside entities (e.g., those used by the Western Climate Initiative) for administering and providing financial services for the auction.

The bill also calls for a price containment reserve and a hard price cap. Unlike California's program, which would distribute allowances through a reserve sale, HB 2020 envisages a reserve auction. It also directs the CPO to establish a hard price ceiling for 2021, to create a schedule for the price ceiling to increase by a fixed percentage over inflation, and to set prices in a manner that enables linkage. Lastly, the bill establishes a special allowance set-aside for the electric sector. This is intended to protect ratepayers from cost increases due to increases in emissions that may result from events outside the control of electricity system managers, such as poor hydroelectric years.

Formal discussions between California and Oregon of potential program linkage cannot occur until the legislation has been adopted. Knowing this, WPTF has urged the Legislature to provide the CPO with limited flexibility to modify the program, if changes are needed to enable program linkage.

...As Washington Goes Its Own Way Again

In Washington, Democratic legislators have been busy working on bills to implement Governor Inslee's climate change agenda. The two most prominent are a Clean Transportation bill, modeled on the low-carbon fuel standard in California and Oregon, and the Clean Electricity Standard. Rumors have swirled since January that a cap-and-trade bill will be introduced to replace the Clean Transportation bill, but despite an outline and a draft floating around, it is not clear that the Legislature has the appetite to consider cap and trade during this session.

Meanwhile, the Washington Senate is working quickly to move the Clean Electricity Standard bill. The Senate's version, which seems to have the most traction, would require Washington utilities to eliminate coal-fired electricity from retail rates by 2025. As of 2030, 100% of electricity used to serve load would need to be carbon neutral. Through 2044, 80% of load would have to be served by renewable or non-emitting resources. The remaining 20% of load can be made carbon neutral through retirement of unbundled renewable energy credits, investments in energy transformation projects, or through a $60/megawatt-hour (MWh) alternative compliance payment. As of 2045, 100% of electricity used to serve load must by supplied by renewable or non-emitting generation.

There are several problems with this bill: First, unlike California's clean energy rules for the portion of load beyond the 60% Renewable Portfolio Standard (RPS), the Washington bill would establish an annual compliance requirement. (As of now, it appears that California will implement the 40% carbon-free requirement above the 60% RPS solely through the Integrated Resource Planning process.) However, a bigger concern is the potential problems this bill would cause for Washington utilities that participate in the EIM. As currently drafted, it appears that the bill would attribute emissions associated with all unspecified purchases, including EIM purchases, to each utility. Because the utilities that participate in the EIM would not be able to determine which resources are dispatched via the EIM, they could not control their carbon exposure for EIM purchases. EIM purchases could thus result in a $60/MWh compliance obligation for participating Washington utilities. Such an outcome would pose a significant barrier to ongoing and expanded participation of Washington utilities in the EIM, or the expanded day-ahead market. In response to this concern, WPTF and other stakeholders are advocating for rulemaking to determine how resources dispatched in the EIM would be assigned to Washington utilities.