UTAH STATE BAR
ENERGY, NATURAL RESOURCES AND ENVIRONMENTAL LAW SECTION

Energy Committee

Selected Developments 2015-2016

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I. NOTABLE JUDICIAL DECISIONS

A. United States Supreme Court

1. Federal Energy Regulatory Comm'n v. Electric Power Supply Ass'n, No. 14-840 (U.S. April 19, 2016).

The U. S. Supreme Court's April 19 ruling that a Maryland program providing long-term rate guarantees to an entity that agrees to build a new power plant in the state intrudes on the jurisdiction of the Federal Energy Regulatory Commission ("FERC") was unanimous and straightforward. The 8-0 decision avoided delving into some of the more difficult issues involving where the jurisdictional line should be drawn between states and FERC. Instead, the court determined that the Maryland program "disregards the interstate wholesale rate required by FERC." States may still encourage production of new or clean generation, but they must do so in a way that is "untethered to a generator's wholesale market participation."

The dispute centered on a Maryland program developed out of concern that the one- to three-year rate guarantees provided by PJM's capacity market fail to provide the financial assurances needed for a developer to build a new power plant in the state. Maryland wanted to provide a contract with a fixed rate to be in effect for twenty years. The Maryland program required that the state's utilities sign contracts with developers to pay a specific amount for capacity over the length of the contract regardless of the prices set by the PJM market. The Maryland program required the new generator to clear the PJM Interconnection's capacity market.

Several lower courts found that the Maryland program and a similar one in New Jersey intruded on FERC's exclusive jurisdiction. The U.S. Supreme Court agreed.

After issuing the Maryland case decision, the Supreme Court refused to hear appeals over the New Jersey program. This keeps in place a lower court opinion rejecting that state's program.

2. Michigan v. Environmental Protection Agency, No. 14-46 (U.S. June 29, 2015).

The Clean Air Act ("CAA") directs the Environmental Protection Agency ("EPA") to regulate emissions of hazardous air pollutants from certain stationary sources. The EPA may regulate power plants under this program only if it concludes that regulation is appropriate and necessary after studying hazards to public health posed by power-plant emissions. EPA found power-plant regulation appropriate because the plants' emissions pose risks to public health and the environment and because controls capable of reducing these emissions were available and other CAA requirements did not eliminate these risks. Petitioners, including 23 states, sought review of EPA's final rule because EPA refused to consider costs in its decision to regulate. The D.C. Circuit upheld the rule and EPA's refusal to consider costs.

The Supreme Court ruled that EPA was unreasonable in its interpretation of 42 U.S.C. § 7412 when it deemed cost irrelevant. The EPA must consider cost, including the cost of compliance, before deciding whether regulation of power plants is appropriate and necessary. However, it is up to the EPA to decide how to account for cost.

B. United States Court of Appeals for the D.C. Circuit

1. *Xcel Energy Servs. Inc. v. Federal Energy Regulatory Comm'n, No. 14-1282 (March 8, 2016).*

Southwest Power Pool ("SPP"), a regional transmission organization ("RTO"), filed a tariff revision pursuant to section 205 of the Federal Power Act ("FPA") to implement the formula rate of a non-jurisdictional participating transmission owner, Tri-County Electric Cooperative, Inc. ("Tri-County"). To carry out the statutory mandate that rates be just and reasonable, the Commission subjects the revenue requirements of non-jurisdictional participating owners to review under section 205 standards. Unless there is no material issue, the Commission will either suspend the proposed rates while it conducts a section 205 review or allow the rates to take effect where the non-jurisdictional entity voluntarily agrees to make refunds if the Commission determines the rates are unfair and unjust. In this instance, contrary to section 205's mandate and Commission precedent, and over formal protests by intervenors, the Commission, despite concluding that the proposed rates may be unjust and unreasonable, allowed them to go into effect without suspension or a voluntary refund commitment by Tri-County. On rehearing, the Commission admitted its error of law but concluded that the only available remedy was prospective relief under section 206 of the FPA. The Commission ruled that retroactive suspension of the rates would be inconsistent with its regulations barring suspension of a rate schedule after it took effect. Xcel petitioned for review.

To the extent the Commission denied Xcel relief because FERC lacks authority to order refunds from Tri-County, a non-jurisdictional entity, this argument was misplaced. Xcel did not argue that the Commission has authority under the FPA to order refunds from Tri-County. Rather, Xcel argued that the Commission may exercise its remedial authority with respect to SPP, whose OATT was unlawfully inflated by Tri-County's revenue requirement, resulting in unlawful rates. SPP filed proposed rates as revisions to its tariff. The rates were charged by SPP to SPP's customers and were associated with service purported to be provided by SPP, not by Tri-County. SPP controls the transmission facilities that provide the services and has the tariff under which the services are provided.

Furthermore, the Commission ignores what distinguishes the instant case. It has conceded an error of law by failing, contrary to section 205's mandate, to ensure SPP's rates were just and reasonable before they took effect or provide refund protection. Where the Commission acknowledges that it acted contrary to section 205's mandate to protect against unjust and unreasonable rates, its initial rate order was *ultra vires*. The Commission cannot rationally ignore the different contexts between this case and those in which it has refused to suspend existing rate schedules found just and reasonable. The court remanded the case to the Commission for appropriate action.

C. United States Court of Appeals for the Second Circuit

Allco Finance Ltd. v. KLEE, Docket No. 15-20 (2d Cir. Nov. 6, 2015).

Allco brought this action against Defendant Robert Klee ("Commissioner") in his official capacity as Commissioner of the Connecticut Department of Energy and Environmental Protection, alleging that the Commissioner's actions are preempted by the Federal Power Act ("FPA") and the Public Utility Regulatory Policies Act ("PURPA"). In addition to seeking damages and fees, Allco sought equitable relief in the form of voiding the intervenors' contracts and enjoining the Commissioner from violating the FPA and PURPA in any future state procurement process. The District Court for the District of Connecticut entered judgment dismissing Allco's complaint. The Second Circuit held that (1) Allco cannot bring claims under §§ 1983 and 1988 to vindicate any rights conferred by PURPA because PURPA's private right of action forecloses these remedies; (2) Allco failed to exhaust its administrative remedies, a prerequisite for any QF to bring an equitable action seeking to vindicate specific rights conferred by PURPA; and (3) Allco lacks standing to bring a preemption action seeking solely to void the contracts awarded to intervenors in the state procurement process.

The FPA gives FERC exclusive authority to regulate sales of electricity at wholesale in interstate commerce. States may not act in this area unless Congress creates an exception. PURPA contains one such exception that permits states to foster electric generation by certain power production facilities (QFs) that have no more than 80 MW of capacity and use renewable generation technology. PURPA imposes obligations on each state regulatory authority to implement PURPA regulations. It also provides a private right of action to qualifying cogenerators to enforce a state's obligations under PURPA.

Connecticut implemented a state statute that empowered the Commissioner to solicit proposals for renewable energy projects, select winners, and direct Connecticut's utilities to enter into wholesale energy contracts with the winners. After failing to be selected to win such a contract, Allco filed a complaint alleging the Commissioner's implementation of the procurement statute was preempted by the FPA.

Allco did not seek to enforce PURPA's requirements through the private right of action contained within PURPA. Instead, Allco brought a claim under 42 U.S.C. § 1983 and a preemption claim for regulating wholesale sales. The court found that PURPA's conferral of a private right of action requiring compliance with specific pre-lawsuit procedures strongly indicates Congress's intent to foreclose a separate remedy under § 1983.

The court also affirmed the district court's dismissal of Allco's claims seeking equitable relief regarding future procurements conducted by the Commissioner. For such relief to redress Allco's alleged injury, it must be likely, as opposed to merely speculative that Allco receive the contract that it seeks. Allco must show, at a minimum, that the requested relief, to invalidate the Commissioner's prior selections and void the existing contracts, provides a path for Allco to eventually obtain a procurement contract. But invalidating the contracts would simply deny Allco's competitors a contractual benefit without redressing Allco's injury. Therefore, Allco lacks standing to seek such equitable relief.

Finally, PURPA requires administrative exhaustion for claims brought by QFs attempting to enforce the requirements. Even though Allco tried to characterize its claim differently, its claim is still covered by the PURPA administrative exhaustion requirement.

D. United States Court of Appeals for the Seventh Circuit

MISO Transmission Owners v. Federal Energy Regulatory Comm'n, Nos. 14-2153, 14-2533, 15-1316 (7th Cir. April 6, 2016).

This is another win for FERC's Order 1000. In Order 1000, FERC ordered jurisdictional utilities to remove from their FERC-approved tariffs and agreements any provisions granting them the right of first refusal ("ROFR") to build new transmission projects selected in Midcontinent Independent System Operator's ("MISO") regional planning process and eligible for region-wide cost allocation. Transmission owners would now have to compete with other developers to build regional transmission projects.

On April 6, 2016, the Seventh Circuit Court of Appeals issued its decision rejecting challenges by transmission owners in the MISO to FERC's directive that they give up their contractual ROFR to build new regional transmission projects. The U.S. court of Appeals for the District of Columbia Circuit in August 2014 upheld Order 1000, including its ROFR directive, finding FERC had adequately justified the requirements. The MISO transmission owners' attack on the provision differed in that they claimed FERC must presume that MISO's contract with them containing a ROFR is reasonable and therefore protected. They further argued the ROFR was not intended to curtail competition but rather to recognize that "competition in transmission development was not contemplated," and its purpose was simply to allow MISO to require transmission owners to build needed facilities in their service areas.

Judge Posner said that the transmission owners made no effort to show that maintaining their ROFR was in the public interest. Although the MISO transmission owners' ROFR "originated as a contract right based on arms'-length negotiations among the companies that joined MISO and was thus a right created by contract, contract rights are not sacred, especially when they curtail competition." "A market that can support only one firm because conditions of supply and demand leave room for no more . . . has no need for a [ROFR]." Any concern that the facilities identified by MISO as being needed will not get built without the ROFR is unfounded given the firms now willing to compete to build these new facilities.

A different argument addressed by the court centered on "baseline reliability projects," the sole purpose of which is to resolve reliability issues. FERC allows incumbent transmission owners to retain ROFR's for these types of projects. A developer argued that this decision to allow this ROFR in this case violates Order 1000. The court struck down this challenge. The ROFR exception is limited to only those reliability projects that confer largely local benefits. FERC's justification for this departure is the benefit of a quick resolution to reliability problems.

E. United States Court of Appeals for the Ninth Circuit

1. *State of California v. Federal Energy Regulatory Comm'n, No. 13-71276 (9th Cir. Dec. 17, 2015).*

The *Mobile-Sierra* doctrine requires FERC to presume that the rate set in a freely negotiated wholesale-energy contract was just and reasonable. This case addresses a set of appeals that stem from the western energy crisis of 2000-2001. Petitioners challenge the applicability of the *Mobile-Sierra* doctrine to certain types of contracts.

In *Port of Seattle*, the Ninth Circuit reviewed several challenges to FERC's denial of refunds to wholesale buyers of electricity that purchased energy in the Pacific Northwest spot market at unusually high prices, remanding FERC's denial of refunds to wholesale buyers. After the remand, FERC planned evidentiary hearings and took the position, for the first time in the case, that it would invoke the *Mobile-Sierra* doctrine. The presumption that the rates set forth in the short-term bilateral power contracts at issue were just and reasonable could only be overcome or avoided if specific criteria were met, such as "where it can be shown that one party to a contract engaged in such extensive unlawful market manipulation as to alter the playing field for contract negotiations."

Invoking the *Mobile-Sierra* doctrine for purposes of the hearing meant that FERC would limit the scope of evidence permitted in the proceeding. Buyers would need to demonstrate that a particular seller engaged in unlawful market activity in the spot market and that such unlawful activity directly affected the particular contract or contracts to which the seller was a party. Therefore, general allegations of market dysfunction would be insufficient to avoid or overcome the presumption. According to FERC, a market-wide remedy would be inappropriate because the Pacific Northwest spot market, like those in most of the west, operated solely through bilateral contracts.

The regulatory system created by the FPA is premised on contractual agreements voluntarily devised by regulated companies; it contemplates abrogation of these agreements only in circumstances of unequivocal public necessity. Where the *Mobile-Sierra* doctrine applies, the inquiry into whether the rate is lawful focuses on whether the contract rate seriously harms the public interest.

Under *Chevron*, the court deferred to FERC's reasonable determination that *Mobile-Sierra* extends to the context of short-term spot sales. The mere short-term nature of these spot sale contracts does not render FERC's application of the doctrine unreasonable. Under *Morgan Stanley*, the Supreme Court has drawn the rule so that the presumption may be invoked with regard to any contracted-for rate. The fact that some contracts adopted the form of the WSPP Agreement does not change the analysis, as the sales were still made pursuant to contracts. After the presumption is invoked, the parties may avoid or rebut it based on an evidentiary showing, but FERC's baseline assumption that the presumption applies to the contracts at issue is not unreasonable in light of *Morgan Stanley*.

F. <u>Utah Court of Appeals</u>

1. Metropolitan Water Dist. v. Questar Gas Company, 2015 UT App 265.

The water district ("District") owns and operates the Salt Lake Aqueduct ("SLA"), a water pipeline that delivers water from Deer Creek reservoir to the Little Cottonwood Water Treatment Plant before carrying the treated water to various storage facilities. It was constructed as part of the Bureau of Reclamation's ("BOR") Provo River Project. The portion of the SLA at issue in this case was constructed within a non-exclusive easement reserved by a federal land patent dated May 5, 1898. In 1955, after construction of the SLA, the land encumbered by the SLA was dedicated to Salt Lake County for public use.

Questar maintains a natural gas pipeline which runs parallel to the SLA. It was installed pursuant to two gas franchises granted by Salt Lake County. Before constructing its pipeline, Questar also entered into a fifty-year license agreement with the BOR on December 5, 1956. In the license agreement, Questar's pipeline was acknowledged to "not be incompatible with the purposes for which the [easements for the SLA] were acquired and are being administered." The license agreement expired December 5, 2006.

Two months before the license agreement expired, the BOR quitclaimed the SLA to the District. After the license agreement expired, the District asked Questar to sign a new license agreement for the continued presence of Questar's pipeline, subjecting Questar to the District's regulations. Questar would not agree because it claimed it was not subject to the District's regulations by reason of its franchise agreement with Salt Lake County. Thereafter, the District filed a complaint against Questar and then a motion for summary judgment seeking a declaratory judgment that Questar's pipeline now belongs to the District, the District has statutory authority to require Questar to enter into a license agreement for continuing to occupy the SLA corridor, and failing that, Questar's continued presence constitutes a trespass, interference with a waterway and a public nuisance. The lower court denied the District's motion. The District agreed to dismiss its action without prejudice and then appealed to the Utah Court of Appeals.

The Court of Appeals determined that because the District has neither express nor implied authority to regulate Questar or any other public utilities, its rights against Questar are purely those which it has under property law as the owner of an easement. The court further found that under the present facts, there is no indication that Questar's pipeline unreasonably interferes with the SLA. The pipelines have peacefully coexisted for more than six decades, and they more or less burden each other equally. The District's claim that Questar's pipeline will interfere with its future construction plans is purely speculative at this time.

II. ADMINISTRATIVE INITIATIVES AND ACTIONS

A. <u>Utah Public Service Commission Cases</u>

1. In the Matter of Rocky Mountain Power's Proposed Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities, Docket No. 15-035-T06.

Schedule 37 establishes standard prices for purchases of power from Utah-located cogeneration Qualifying Facilities ("QF") with a design capacity of 1,000 kW or less and small power production QFs with a design capacity of 3,000 kW or less. The rates are based on avoided costs, which are the costs Rocky Mountain Power would incur to serve its native load but for the generation the QF provides. Schedule 37 prices also may be used to evaluate special contracts and form the basis of credits paid under Rocky Mountain Power's Net Metering Service tariff, Schedule No. 135.

On September 18, 2015, the Commission accepted Rocky Mountain Power's proposal to remove the single-cycle-combustion-turbine ("SCCT") capacity cost from the calculation of avoided costs and include front-office-transaction ("FOT) costs that represent short-term firm purchases it plans to make to meet its short-run capacity needs as identified in its 2015 Integrated

Resource Plan ("IRP"). The Commission also accepted Rocky Mountain Power's proposal to shape the average monthly avoided energy costs into distinct on-peak and off-peak costs based on the relationship of Palo Verde on-peak and off-peak market prices to Palo Verde average market prices.

2. In the Matter of the Application of Rocky Mountain Power for Approval of its Subscriber Solar Program (Schedule 73), Docket No. 15-035-61.

On October 21, 2015, the Commission approved a settlement agreement establishing a Subscriber Solar Program. The program provides Utah customers with the optional opportunity to buy kWh blocks of electricity from Rocky Mountain Power solar resources at a fixed price and then use that purchased energy to offset a portion of the customer's own billed energy usage.

3. In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program, Docket No. 14-035-114.

In Utah Code § 54-15-105.1, the Utah Legislature required the Commission to determine whether costs Rocky Mountain Power and other customers incur from a net metering program exceed the benefits of the net metering program and to determine a charge, credit, or ratemaking structure in light of the costs and benefits of the net metering program. On November 10, 2015, the Commission issued an order that constituted a further step toward fulfilling this task. The order establishes an analytical framework for assessing the costs and benefits of net metering.

The analysis will compare PacifiCorp's actual cost of service to the cost of service that would exist but for net metering customers' self-generation. The costs and benefits will be analyzed over a one-year period commensurate with the test period Rocky Mountain Power uses in its next general rate case.

4. In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities, Docket No. 15-035-53.

On May 11, 2015, Rocky Mountain Power filed an application with the Commission, requesting approval to modify the maximum contract term for prospective power purchase agreements ("PPA) with Qualifying Facilities ("QF") as that term is used in the Public Utility Regulatory Policies Act of 1978 ("PURPA"). The application asked the Commission to reduce the maximum term of a QF's PPA from twenty-years to three-years. On January 7, 2016, the Commission issued its order setting the maximum contract term to fifteen-years. The order does not alter the terms of existing QF PPAs, but exiting QF PPAs would be subject to the 15-year limit after their current term expires. The order applies to any QF that had not executed a PPA with Rocky Mountain Power as of the date of the order.

B. Environmental Protection Agency Regulations[1]

Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,661 (Oct. 23, 2015).

[1] While these rules should technically be included in the Environmental Section Update, they are so important to the energy industry that the Energy Update would be remiss in not mentioning them.

In August 2015, the Environmental Protection Agency released the final version of the Clean Power Plan ("CPP"), setting forth carbon emissions standards for existing power plants. It is expected to reduce CO_2 emissions by 32% by 2030 based on 2005 emission levels. The rule was published in the Federal Register on October 23, 2015, and made effective December 22, 2015.

An appeal by 29 states and state agencies to block the CPP from going into effect was rejected by the District of Columbia Court of Appeals in January 2016. These states then appealed to the U. S. Supreme Court. On February 9, 2016, the U.S. Court put the implementation of the plan on hold while the D.C. Circuit hears arguments against the rule. Arguments are scheduled for June 2, 2016. It is fully expected that no matter how the D.C. Circuit rules, the decision will be appealed to the U.S. Supreme Court. The death of Justice Scalia has further fueled speculation about what the outcome might ultimately be.

At least 19 states have decided to move forward with implementation of the CPP despite the stay. At least another 21 states have stopped working on implementation. Utah is one of those who has stopped working on implementation. Utah is also one of the states who have joined the suit in the D.C. Circuit against the CPP.

C. Federal Energy Regulatory Commission Regulations

1. 153 FERC ¶ 61,065, Docket No. RM14-14-000, Order No. 816, Final Rule.

On October 15, 2015, the Federal Energy Regulatory Commission ("FERC") issued a final rule to clarify and streamline certain aspects of its market-based rate program for wholesale sales of electric energy, capacity and ancillary services. The rule went into effect January 28, 2016.

FERC codified its market-based rate policy through Order No. 697, issued in 2007. This final rule found the burdens associated with certain requirements outweighed the benefits in some circumstances. The rule clarifies that sellers need not report behind-the-meter generation in the indicative screens and asset appendices. The final rule defines the default relevant geographic market for an independent power producer ("IPP") located in a generation-only balancing authority area as the balancing authority area of each transmission provider to which the IPP's generation-only balancing authority area is directly interconnected. It requires a market-based rate seller to report in its indicative screens and asset appendices all long-term firm purchases of capacity and/or energy that have an associated long-term firm transmission reservation, regardless of whether that seller has operational control of the generation capacity supplying the purchased power.

2. 153 FERC ¶ 61,229, Docket No. RM15-2-000, Order No. 819, Final Rule.

This final rule, issued on November 20, 2015, allows the sale of primary frequency response service at market-based rates by sellers with market-based rate authority for sales of energy and capacity. Primary frequency response service is one of the tools available to help maintain system frequency within predetermined boundaries above and below 60 Hertz to ensure reliable operation of the North American electric system. This final rule defines primary frequency response service as a resource standing by to provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over. It is expected that the rule will promote competition in anticipation of growing demand for primary frequency response service as a result of a reliability standard taking effect in 2016 that requires balancing authorities to meet a minimum frequency response obligation.

3. 153 FERC ¶ 61,309, Docket No. RM16-3-000, Notice of Proposed Rulemaking.

FERC proposed to revise the ownership information that sellers must provide when seeking to obtain or retain electric market-based rate authority. FERC permits power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal and vertical market power. Currently, a seller must identify all upstream owners, and describe the business activities of the owners and whether they are involved in the energy industry. This proposed rule would require market-based rate sellers to provide ownership information on only those affiliates necessary for the Commission's assessment of horizontal or vertical market power, and removes the need to identify other owners. A seller would be required to identify and describe two categories of affiliate owners: (1) Ultimate affiliate owner(s) – the furthest upstream affiliate owner(s) in the ownership chain; and (2) Affiliate owners with franchised service areas or market-based rate authority; or that directly own or control generation, transmission, intrastate natural gas transportation, storage or distribution facilities, physical coal supply sources, or access to transportation of coal supplies.

5. 154 FERC ¶ 61,222, Docket No. RM16-8-000, Notice of Proposed Rulemaking.

FERC proposed revisions to its small generator interconnection policy to reflect the need for those generators to "ride through" and stay connected during abnormal frequency and voltage events. Changing industry conditions and the increasing presence and impact of distributed energy resources on the electric system now require the extension of that capability to small generators similar to the requirements for generators larger than 20 MW. Therefore, FERC would revise the pro forma Small Generator Interconnection Agreement ("SGIA") adopted in Order No. 2006 and amended in Order No. 792 to require generators 20 MW or smaller signing new SGIAs to ride through abnormal frequency and voltage events, and not disconnect during those events. This would only apply to small generator interconnections subject to FERC jurisdiction.

III. UTAH LEGISLATION

A. Sustainable Transportation and Energy Plan Act, S.B. 115, 2016 Leg., 61st Sess.

This bill, proposed by Rocky Mountain Power, eliminates the 70/30 sharing band in the current energy balancing account ("EBA") that was imposed to ensure Rocky Mountain Power shareholders share risks with ratepayers. The bill now allows Rocky Mountain Power to recover 100% of its costs with no risk sharing. It allows Rocky Mountain Power to capitalize demand-side management costs, end the current solar incentive program, and recover from ratepayers funds to accelerate depreciation of its thermal generation. It also allows creation of a program for electric vehicle charging station rates.

IV. MISCELLANEOUS

A. Dominion Resources Acquisition of Questar Corporation

On February 1, 2016, Dominion Resources, Inc. and Questar Corporation announced an agreement for the companies to combine, in an all-cash transaction in which Dominion has agreed to pay Questar shareholders $25 per share and assume Questar's outstanding debt. The transaction would be accretive to Dominion upon closing, which is expected by the end of 2016. Pending approvals, Questar will operate as a first-tier, wholly owned subsidiary of Dominion and maintain its significant presence, local management structure, and headquarters in Salt Lake City. Dominion has also agreed to increase community involvement and charitable investment in the communities currently served by Questar.

B. Energy Imbalance Market

The Energy Imbalance Market ("EIM") provides automatic dispatch of least-cost imbalance energy every fifteen-minutes while moderating the variability of renewable generation resources. It was first developed in the California Independent System Operator ("CAISO"). PacifiCorp joined in 2014 and NV Energy, PacifiCorp's Berkshire Hathaway affiliate, joined in 2015. The EIM has had a rocky start with some extreme price volatility, but participating utilities claim it has consistently delivered benefits to the utilities. Puget Sound Energy and Arizona Public Services are scheduled to join in 2016. Portland General Electric is scheduled to join in 2017, and Idaho Power is scheduled to join in 2018. It is yet to be seen how the utilities' participation provides benefits to ratepayers.

C. PacifiCorp to Join CAISO in a Regional ISO

Last year, PacifiCorp announced its decision to study and evaluate the possibility of joining with the CAISO to form a regional ISO. Because the board of CAISO is appointed by the Governor of California, one of the first and biggest challenges will be to develop a new governance design that will make it attractive for utilities throughout the west to participate. CAISO and PacifiCorp are currently conducting stakeholder processes and issuing straw proposals for development of policies such as transmission access charges, greenhouse gas compliance, resource adequacy, and metering. PacifiCorp's current publicly available schedule indicates that it will begin to go to the regulators in its six jurisdictions for permission to go forward with its participation in a regional ISO sometime during the fourth quarter of 2016 or the first quarter of 2017. If PacifiCorp does go forward, it is expected that other utilities, especially others in the EIM, will follow.