REPORT OF THE STATE COMMISSION PRACTICE & REGULATION COMMITTEE

Synopsis: This report summarizes significant state developments in the utility industry from September 2013 through June 2014. This report generally organizes the country into four regions: (I) West and Southwest, (II) South, (III) Midwest and Plains, and (IV) East and Mid-Atlantic.*

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I. WEST AND SOUTHWEST

A. Arizona

1. Net Metering

Arizona requires utilities to credit energy produced by residential solar users each month at the retail rate for energy used by the customer and then pay avoided cost for surpluses.[1] Arizona Public Service Company (APS) builds fixed costs into volumetric energy rates, which means fixed costs are shifted onto customers who pay for electricity use.[2] As the number of net metering customers increases, there are fewer customers paying the fixed costs.[3] On December 3, 2013, the Arizona Corporation Commission (AZCC) issued a decision settling an application from APS that proposed a cost-shift solution to address the rising number of participants in the net metering program for distributed generation (DG) of energy by technologies such as rooftop solar panels.[4] APS' application cited the growing number of residential solar users as evidence of the increased burden caused by net metering on non-solar users to pay for the fixed costs associated with electric transmission and distribution.[5]

The AZCC voted three-to-two to: (1) order APS to implement a $0.70 per kilowatt (kW) per month adjustment for all residential DG installations beginning December 31, 2013; (2) require APS to submit a quarterly report on the increase in DG installations, the kW each DG installation owner uses per month, and the amount of money that comes in per month from the interim price adjustment; (3) establish rules for grandfathering existing users and setting rates for those who sign up under the interim adjustment; and (4) establish a new docket to study the value and costs of DG installations.[6]

The dissent stated that the $0.70 adjustment is inadequate to address the cost shift and that the decision does too little.[7] Commissioner Gary Pierce criticized the majority for failing the 98% of APS customers who do not use DG, contended that the majority addresses only about 10% of the cost shifted, and suggested that the amount of money invested by the interested parties could cause Arizona citizens to question the independence of the AZCC.[8] Commissioner Brenda Burns also criticized the small portion of the cost shift the decision actually covered.[9]

1. ARIZ. ADMIN. CODE §§ R14-2-2301-R14-2-2308 (2009); ARIZ. ADMIN. CODE § R14-2-1801(M) (2007).

2. Arizona Public Service Company's Application for Approval of Net Metering Cost Shift Solution, Decision No. 74202, Docket No. E-01345A-13-0248, at 2-6 (Ariz. Corp. Comm'n Dec. 3, 2013).

3. According to APS, the number of rooftop solar installations increased from 900 to 18,000 between January 2009 and June 2013 and continues to grow. *Id.* at 2.

4. *See generally id.*

5. *Id.* at 2.

6. *Id.* at 29-30. *See also id.* (Comm'r Pierce dissenting).

7. *Id.* (Comm'r Pierce dissenting); *see also id.* (Comm'r Burns dissenting).

8. *Id.* (Comm'r Pierce dissenting).

9. *Id.* (Comm'r Burns dissenting) (discussing the large number of DG users who will continue to shift fixed costs due to the extensive grandfathering provision).

2. Renewable Energy Plans

The Arizona Administrative Code subjects Arizona electric utilities to the Arizona Renewable Energy Standard and Tariff (REST), which requires regulated utilities to procure 15% of energy from renewables by 2025.[10] Pursuant to REST, utilities submit an annual implementation plan (AIP) to the AZCC.[11] The AZCC approved APS' 2014 REST Plan on January 7, 2014.[12] APS' plan proposed a $143.5 million budget.[13] Of that, $107.9 million can be passed onto customers at a maximum rate of $0.010264 per kilowatt hour (kWh).[14] The budget will fund projects including a plan to add to the Arizona Sun Project, a series of photovoltaic power plants.[15] Ten of the fifty megawatts (MW) will come from Luke Air Force Base and ten MW from the City of Phoenix.[16] The AZCC also approved $500,000 for solar water heating incentives of $0.30 kWh for the first year.[17] The AZCC approved Tucson Electric Power Company's (TEP) REST Plan on October 25, 2013.[18] The plan, which totals $40,123,072 in spending with TEP recovering $33,601,642 through customer surcharges, includes $60,000 in solar water heating incentives at $0.40 per kWh, a $28 million plan for the Bright Tucson solar project, and $12 million for a twenty MW solar project at Fort Huachuca for the U.S. Army.[19] On July 30, 2013, the AZCC approved TEP's application for approval of a twenty-year power purchase agreement (PPA) with Red Horse Wind 2, LLC for fifty-one MW of wind energy and three MW of solar energy, which equals 1.5% of TEP's mandatory 15% renewable resources.[20]

3. Renewable Energy Legislation

During its second regular session, Arizona's 51st Legislature passed two bills relating to the economics of renewable energy. First, Senate Bill 1484, signed on April 11, 2014, creates a tax credit for landowners or lessees who invest $300 million in renewable energy facilities and use 90% of the energy produced for

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10. ARIZ. ADMIN. CODE § R14-2-1804 (2007).

11. *Id.* § R14-2-1813.

12. Arizona Public Service Company–Request for Approval of its 2014 Renewable Energy Standard Implementation Plan for Reset of Renewable Energy Adjustor, Decision No. 74237, Docket No. E-01345A-13-0140 (Ariz. Corp. Comm'n Jan. 7, 2014).

13. *Id.* at 14.

14. *Id.* at 15 (capping the per month rate at $4.11 for residential customers, $152.49 for small commercial customers, $256.60 for medium commercial customers, $513.20 for large commercial customers, and $3,335 for industrial customers).

15. *Id.* at 2.

16. *Id.* at 15.

17. *Id.* at 16.

18. Application of Tucson Electric Power Company for Approval of its 2014 Renewable Energy Standard and Tariff Implementation Plan, Decision No. 74165, Docket No. E-01933A-13-0224 (Ariz. Corp. Comm'n Oct. 25, 2013).

19. *Id.* at 20; *see also id.* at 7. One commissioner dissented to the Fort Huachuca project because of costs, saying it is unnecessary for TEP to meet its renewable goals and that the Department of Defense would complete the project without TEP's involvement. *Id.* (Comm'r Burns dissenting).

20. Application of Tucson Electric Power Company for Approval of a Renewable Energy Power Purchase Agreement with Red Horse Wind 2, LLC, Decision No. 74014, Docket No. E-01933A-13-0056, at 1-2 (Ariz. Corp. Comm'n July 30, 2013).

manufacturing self-consumption in Arizona.[21] The credit is capped at $10 million and is to be assigned on a first-come, first-serve basis.[22] If funds are available, recipients can receive $1 million per year per facility up to $5 million total.[23] The law also requires that the credit recipient complete the project within three years of the application or by December 31, 2017, whichever is earlier.[24] Second, Arizona Governor Jan Brewer signed House Bill 2403 on April 30, 2014, establishing a method for determining the depreciated cost of renewable energy equipment for valuing real property abandoned by a lessee who also abandoned the renewable energy equipment.[25] The law sets the cash value of renewable energy equipment at 20% of the depreciated cost.[26] The value of the land with the equipment is the higher of the two previous annual assessments.[27] The law also defines depreciation, original cost, renewable energy equipment, and taxable original cost.[28]

The Arizona legislature also passed Senate Concurrent Resolution 1022, in which the legislature asserts Arizona's primary role in implementing air quality regulations in opposition to the United States Environmental Protection Agency's (EPA) January 8, 2014 regulations.[29] The legislature objects to the regulations because they require technologies the legislature says are not yet commercially available or technologically feasible.[30]

B. Colorado

1. Net Metering

Net metering issues were embedded in Public Service Company of Colorado's (PSCo) application to the Colorado Public Utility Commission (COPUC) for approval of its 2014 Renewable Energy Standard Compliance Plan.[31] In response, the Colorado Energy Office requested that issues related to net metering incentives be severed to a new non-adversarial, investigatory

21. S.B. 1484, 51st Leg., 2d Sess. (Ariz. 2014).

22. *Id.*

23. *Id.*

24. *Id.*

25. H.B. 2403, 51st Leg., 2d Sess. (Ariz. 2014).

26. *Id.*

27. *Id.* (applying only to land classified as agricultural land for two years prior to the lease that resulted in the introduction of the renewable energy equipment).

28. *Id.*

29. S. Con. Res. 1022, 51st Leg., 2d Sess. (Ariz. 2014) (passing the Senate on March 6, 2014 and the House of Representatives on April 14, 2014). The EPA regulations require that new coal electrical generating facilities use carbon capture and sequestration technologies. Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1430 (proposed Jan. 8, 2014) (to be codified at 40 C.F.R. pts. 60, 70-71 and 98).

30. Ariz. S. Con. Res. 1022.

31. Application of Public Service Company of Colorado for Approval of its 2014 Renewable Energy Standard Compliance Plan, No. 13A-0836E (Colo. Pub. Util. Comm'n July 24, 2013), *available at* https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=220996&p_session_id=.

proceeding.[32] The COPUC agreed and in April 2014 held a Commissioners' Information Meeting (CIM) to explore the scope and goals of the proceeding and give interested persons the opportunity to propose suggestions.[33] After the CIM, the COPUC solicited legal briefs on a series of questions[34] and stated an intent to conduct a series of panel discussions addressing: "(1) the present and expected impacts of net metering . . . ; (2) the interrelationships between utility distribution systems and net metered distributed solar generation; and (3) approaches other states have taken."[35]

2. Municipalization

In November 2011, Boulder residents passed a ballot measure allowing the City to create a municipal utility.[36] Although twenty-nine Colorado municipalities own utilities, Boulder is notable because its municipalization effort was, in part, motivated by a desire to reduce greenhouse gas emissions and increase reliance on renewable energy. The measure required that the new utility not exceed rates charged by the current provider at the time of acquisition (i.e., PSCo) and comparable reliability of service; that the utility produce enough revenue to cover operating expenses and debt payments, plus an amount equal to 25% of debt payments; and that the utility have "a plan for reduced greenhouse gas emissions and other pollutants and increased renewable energy."[37]

On May 9, 2013, PSCo filed a petition for declaratory order with the COPUC, which focused on 5800 customers outside of Boulder city limits but who are served by facilities the City intends to acquire.[38] PSCo argued these customers were outside of the municipality and thus would remain in PSCo's service area.[39] The City argued its state constitutional and statutory right to eminent domain, but was unable to persuade the COPUC.[40] In addition, the COPUC declared that the City's condemnation of PSCo's facilities is subject to COPUC preapproval.[41]

32. Application of Public Service Company of Colorado for Approval of its 2014 Renewable Energy Standard Compliance Plan, Decision No. C14-0219-I, Proceeding No. 13A-0836E, ¶¶ 1, 18 (Colo. Pub. Util. Comm'n Feb. 19, 2014).

33. Commission Consideration of Retail Renewable Distributed Generation and Net Metering, Decision No. C14-0294, Proceeding No. 14M-0235E, ¶¶ 3-4 (Colo. Pub. Util. Comm'n Mar. 12, 2014).

34. Commission Consideration of Retail Renewable Distributed Generation and Net Metering, Decision No. C14-0615-I, Proceeding No. 14M-0235E, ¶ 6 (Colo. Pub. Util. Comm'n May 28, 2014).

35. *Id.* ¶ 10.

36. *Third Party Evaluation Information*, CITY OF BOULDER, COLO., https://bouldercolorado.gov/energy-future/energy-future-third-party-evaluation-information (last visited Sept. 20, 2014).

37. *Id.*

38. Verified Petition of Public Service Company of Colorado for Certain Declaratory Orders Concerning the Rights of Public Service Company of Colorado under its Service Territory Certificate Covering Boulder County, Colorado, Proceeding No. 13D-0498E (Colo. Pub. Util. Comm'n May 9, 2013).

39. *Id.* ¶ 8.

40. Verified Petition of Public Service Company of Colorado for Certain Declaratory Orders Concerning the Rights of Public Service Company of Colorado under its Service Territory Certificate Covering Boulder County, Colorado, Decision No. C13-1350, Proceeding No. 13D-0498E (Colo. Pub. Util. Comm'n Oct. 9, 2013).

41. *Id.* ¶ 27.

On January 15, 2015, the City applied for judicial review of the COPUC's decision[42] and, on July 17, 2014, commenced a condemnation action to acquire PSCo's facilities for the proposed municipal utility.[43]

3. Local versus State Control of Oil and Gas Development

A debate exists in Colorado as to whether oil and gas development should be controlled by state or local government. Property rights and environmental concerns are central to the argument for local control. The state legislature did not resolve the conflict during the 2014 session and efforts to negotiate a resolution to be considered at a special legislative session were unsuccessful. Multiple ballot initiatives were poised for consideration on the November 2014 ballot. On August 4, 2014, Governor John Hickenlooper announced the creation of an eighteen-member "blue ribbon" task force that will make recommendations to the legislature in 2015 regarding how to minimize land use conflicts related to oil and gas development.[44] As a result, proponents of the ballot initiatives withdrew them from further consideration.

C. Idaho

1. Public Utility Regulatory Policies Act of 1978 (PURPA)

In recent years, Idaho regulators and utilities have wrestled with competing considerations associated with a sharp increase in small renewable generation development that has tested the bounds of the federal PURPA program mandating purchases from qualifying facilities (QFs).[45] In 2011, the Idaho Public Utilities Commission (IDPUC) established a rule that the eligibility cap for wind and solar QFs to receive published avoided cost rates would be temporarily reduced from an average of ten MW down to one hundred kW, effective December 14, 2010,[46]

42. Petition for Writ of Certiorari or Review, City of Boulder v. Colo. Pub. Util. Comm'n, No. 2014-CV-030047, *petition for cert. filed* (Colo. Dist. Ct. Boulder County Jan. 13, 2014), *available at* https://www-static.bouldercolorado.gov/docs/Petition_for_Writ-1-201401151504.pdf.

43. Petition in Condemnation, City of Boulder v. Pub. Serv. Co. of Colo. (Colo. Dist. Ct. Boulder County July 17, 2014), *available at* https://www-static.bouldercolorado.gov/docs/Petition_in_Condemnation_with_Exhibits-2237-0002-1-201407181003.pdf.

44. Press Release, Gov. John Hickenlooper, Gov. Hickenlooper Announces Task Force to Address Local Control and Land Use Issues (Aug. 4, 2014), *available at* http://www.colorado.gov/cs/Satellite?c=Page&childpagename=GovHickenlooper%2FCBONLayout&cid=1251655966910&pagename=CBONWrapper; Ryan Maye Handy, *18-Person Commission Will Study Oil & Gas in Colorado*, THE COLORADOAN (Aug. 5, 2014, 8:37 AM), http://www.coloradoan.com/story/news/local/2014/08/04/hickenlooper-haults-oil-gas-ballot-initiatives/13579309/.

45. The Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117, requires, among other things, that public utilities purchase power from QFs at the "avoided cost" rate, which is the cost the utility would have paid if it had generated the power itself.

46. Joint Petition of Idaho Power Co., Avista Corp., and PacifiCorp to Address Avoided Cost Issues and to Adjust the Published Avoided Cost Rate Eligibility Cap, Order No. 32176, Case No. GNR-E-10-04, at 10 (Idaho Pub. Util. Comm'n Feb. 7, 2011). Prior to these orders, on December 3, 2010, the Idaho Commission issued Order No. 32131 and opened an investigation into whether it should lower the published avoided cost rate eligibility cap for qualifying facilities from 10aMW to 100kW. Joint Petition of Idaho Power Co., Avista Corp., and PacifiCorp to Address Avoided Cost Issues and to Adjust the Published Avoided Cost Rate Eligibility Cap, Order No. 32131, Case No. GNR-E-10-04 (Idaho Pub. Util. Comm'n Dec. 3, 2010). In doing so, the IDPUC did

and rejected various wind developers' PPAs with Idaho Power Company (Idaho Power) and Rocky Mountain Power, including those of two entities collectively referred to as Grouse Creek Wind Park (Grouse Creek).[47] Significantly, the IDPUC determined that the PPAs exceeded the eligibility size cap and that no legally enforceable PURPA purchase obligation had been established where the QF did not have a fully executed contract prior to December 14, 2010.[48] The IDPUC's Grouse Creek Orders were issued notwithstanding the Federal Energy Regulatory Commission's (FERC or Commission) previous findings that the IDPUC violated PURPA when it rejected similar PPAs.[49]

On March 15, 2013, in response to a PURPA enforcement petition filed by Grouse Creek, the FERC issued an order concurring with Grouse Creek that the IDPUC's orders rejecting the PPAs were inconsistent with the requirements of PURPA and also stating the intent of the Commission to file an enforcement action in federal court against the IDPUC.[50] On March 22, 2013, the FERC filed its enforcement action in the United States District Court for the District of Idaho.[51] The case subsequently settled on December 24, 2013, with the execution of a Memorandum of Agreement (MOA) between the IDPUC and the FERC,[52] wherein the IDPUC acknowledged that a legally enforceable obligation under PURPA may exist before the parties formalize a contract.[53]

On November 29, 2013, Idaho Power submitted an application to the IDPUC requesting the IDPUC to reassess how integration costs for wind energy projects are calculated.[54] Idaho Power's filing is intended to address the need for increased operating reserves to support the variability of wind resources and how such costs are factored into an adjustment of the avoided costs it pays to wind projects that are PURPA QFs. In its filing, Idaho Power asserted that current integration cost

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not immediately reduce the eligibility but gave notice that its decision, when finalized, would be effective retroactive to December 14, 2010. *Id.* at 5-6.

47. *See, e.g.*, Application of Idaho Power Company for a Determination Regarding a Firm Energy Sales Agreement between Idaho Power and Grouse Creek Wind Park, LLC, Order No. 32257, Case Nos. IPC-E-10-61, IPC-E-10-62 (Idaho Pub. Util. Comm'n June 8, 2011); Reconsideration on Remand, Order No. 32365, Case Nos. IPC-E-10-61, IPC-E-10-62 (Idaho Pub. Util. Comm'n Sept. 7, 2012).

48. Application of Idaho Power Co. for a Determination Regarding a Firm Energy Sales Agreement between Idaho Power & Grouse Creek Wind Park, LLC, Order No. 32257, Case Nos. IPC-E-10-61, IPC-E-10-62, at 9 (Idaho Pub. Util. Comm'n June 8, 2011).

49. *Cedar Creek Wind, LLC*, 137 F.E.R.C. ¶ 61,006 at P 1 (2011); *Rainbow Ranch Wind, LLC*, 139 F.E.R.C. ¶ 61,077 (2012); *Murphy Flat Power, LLC*, 141 F.E.R.C. ¶ 61,145 (2012). In these orders, the FERC explained that a QF can benefit from a utility's legally enforceable PURPA purchase obligation prior to a PPA being memorialized.

50. *Grouse Creek Wind Park, LLC*, 142 F.E.R.C. ¶ 61,187 at P 1 (2013).

51. FERC v. Idaho Pub. Util. Comm'n, No. 1:13-cv-141 (D. Idaho filed Mar. 22, 2013), *available at* www.plainsite.org/dockets/download.html?id=33485049&z=d369b67c.

52. MEMORANDUM OF AGREEMENT BETWEEN THE FEDERAL ENERGY REGULATORY COMMISSION AND THE IDAHO PUBLIC UTILITIES COMMISSION (Dec. 24, 2013), *available at* http://www.ferc.gov/legal/mou/mou-idaho-12-2013.pdf.

53. *Id.*

54. Application of Idaho Power Company to Update its Wind Integration Rates and Charges, Case No. IPC-E-13-22 (Idaho Pub. Util. Comm'n Nov. 29, 2013) [hereinafter Case No. IPC-E-13-22], *available at* http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1322/20131129APPLICATION.PDF. Idaho Power currently has twenty-eight wind projects connected to its grid with a capacity of 577 MW, largely in connection with PURPA projects. 505 MW have come online since 2010. *Id.* ¶ 2.

calculations under-collect these costs.[55] Currently, integration costs are calculated based on a percentage of the avoided cost rate set by the IDPUC. For projects 100-300 MW, 301-500 MW, and 501 MW, the percentages are 7%, 8%, and 9%, respectively, of the associated cost of $6.50 per MWh based on a 2007 study.[56] The updated 2013 study shows an integration cost of $6.83 per MWh at 800 MW, $10.22 per MWh at 1,000 MW, and $14.22 per MWh at 1,200 MW.[57]

Idaho Power proposed that the fixed integration amount be based on wind penetration, as opposed to a percentage of the avoided cost rate of allocation.[58] In the alternative, Idaho Power suggested decoupling the wind integration charge from the avoided cost rate and assessing wind integration costs through a separate tariff charge.[59] As of June 11, 2014, the IDPUC is taking comments on Idaho Power's application.[60]

In an order issued May 13, 2014, the IDPUC denied Idaho Power's application requesting temporary suspension of its purchase obligations under PURPA for solar QFs.[61] This application came in connection with a study of the costs of solar integration that Idaho Power had begun in 2013, in response to increased solar development. Idaho Power asserted that it was negotiating thirty-one solar power projects with a cumulative capacity of 501 MW,[62] and that it sought the temporary suspension to avoid the "irreparable harm" from the "run on the bank" phenomena due to the pending conclusion of its solar integration study.[63] Despite the denial, the IDPUC left open a few alternatives, including a suggestion that "placeholder" integration charges be negotiated during contract formation and that it may be appropriate for the company to calculate integration

55. *Id.* ¶ 9.

56. Order No. 30488 approved a three-tiered wind integration cost schedule, based on a 2007 Wind Integration Study, with costs remaining fixed throughout the twenty-year term of the contracts. Idaho Power Co.'s Petition to Increase the Published Rate Eligibility Cap for Wind-Powered Small Power Production Facilities; and To Eliminate the 90%/110% Performance Band for Wind-Powered Small Power Production Facilities, Order No. 30488, Case No. IPC-E-07-03, at 8 (Idaho Pub. Util. Comm'n Feb. 20, 2008), *available at* http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE0703/ordnotc/20080220FINAL_ORDER_NO_30488.PDF; IDAHO POWER, OPERATIONAL IMPACTS OF INTEGRATING WIND GENERATION INTO IDAHO POWER'S EXISTING RESOURCE PORTFOLIO (2007), *available at* https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/wind/Petition_ReviseAvoidedCostRates1.pdf?id=238&.pdf).

57. Case No. IPC-E-13-22, *supra* note 54, at 5-6.

58. *Id.*

59. *Id.* at 6.

60. Idaho Power Co.'s Application to Update its Wind Integration Rates and Charges, Order No. 33054, Case No. IPC-E-13-22 (Idaho Pub. Util. Comm'n June 11, 2014), *available at* http://www.puc.idaho.gov/orders/recent/Notice_of_Modified_Procedure_Order_No_33054.pdf.

61. Idaho Power Company's Petition to Temporarily Suspend its PURPA Obligation to Purchase Energy Generated by Solar-Powered Qualifying Facilities, Case No. IPC-E-14-09 (Idaho Pub. Util. Comm'n May 13, 2014), *available at* http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1409/20140514PETITION.PDF; Idaho Power Co.'s Petition to Temporarily Suspend its PURPA Obligation to Purchase Energy Generated by Solar-Powered Qualifying Facilities, Order No. 33043, Case No. IPC-E-14-09 (Idaho Pub. Util. Comm'n May 28, 2014) [hereinafter Order No. 33043].

62. Order No. 33043, *supra* note 61.

63. *Id.* at 1, 7.

charges based on the approved wind integration cost rate ($6.50/MWh) as a temporary measure until appropriate solar integration charges are approved.[64]

2. Idaho Power

On March 21, 2014, the IDPUC granted Idaho Power's application for approval of a new "base level" net power supply expense (NPSE).[65] The NPSE updates base rates effective June 1, 2014, and is the basis for quantifying 2014/2015 power cost adjustment (PCA) rates as of June 1, 2014. The NPSE had not been analyzed since 2010, and Idaho Power stated that it was under-collecting costs because considerable changes had occurred in the NPSE components.[66] In particular, Idaho Power (i) experienced a decrease in the overall value of its surplus power due to lower market prices, (ii) excluded revenue and load from the 2013 base level NPSE due to the 2012 expiration of a special contract with Hoku, and (iii) experienced a 113% increase in PURPA expenses.[67] Without the NPSE readjustment, the uncollected costs were being recovered through the PCA.[68] The approved proposal has the effect of switching recovery of these cost increases from the PCA to the base level NPSE and decreasing the PCA by the same amount, resulting in a zero net impact on customer rates.

D. Montana

On December 20, 2013, NorthWestern Energy (NorthWestern) filed an application with the Montana Public Service Commission (MTPSC) seeking approval to purchase eleven hydroelectric dams located in Montana that are currently owned by PPL.[69] The purchase is valued at $900 million and would affect "[a]pproximately 340,000 Montana ratepayers who utilize the services and energy provided by NorthWestern."[70] The MTPSC is expected to issue an order approving or disapproving of the sale by September 16, 2014.[71]

In June 2014, the MTPSC approved rate increases for NorthWestern to compensate for outages at Colstrip Unit 4 (CU4), one of NorthWestern's coal

64. *Id.* at 6-7.

65. Application of Idaho Power Co. for Authority to Establish a New Base Level of Net Power Supply Expense, Order No. 33000, Case. No. IPC-E-13-20 (Idaho Pub. Util. Comm'n Mar. 21, 2014).

66. Application of Idaho Power Co. for Authority to Establish a New Base Level of Net Power Supply Expense, Case. No. IPC-E-13-20, at 1-2 (Idaho Pub. Util. Comm'n Nov. 1, 2013).

67. *Id.* at 2, 5.

68. PCA is a rate mechanism used to recover from or return to customers the annual difference between the estimated costs for fuel and purchased power and the actual costs. PCA is intended to account for annual fluctuations rather than the long-term recovery of fixed changes in costs. The base level NPSE, on the other hand, includes the primary fixed costs and can change only when the IDPUC approves a general rate case. *Id.* at 2.

69. Press Release, Mont. Pub. Serv. Comm'n, PSC Receives NorthWestern Filing for PPL Dam Purchases (Dec. 20, 2013), *available at* http://psc.mt.gov/news/pr/?year=2013.

70. *Id.*

71. Application of NorthWestern Energy for Hydro Assets Purchase, Order No. 7323b, Docket No. D2013.12.85, ¶ 4 (Mont. Pub. Serv. Comm'n Jan. 16, 2014).

plants.[72] The MTPSC's decision sparked controversy among consumer advocates who argue that customers are paying for CU4's operational problems.[73]

E. Nevada

1. MidAmerican Energy Holdings Company (MidAmerican Holdings)

On December 17, 2013, the Public Utilities Commission of Nevada (NVPUC) approved MidAmerican Holdings' acquisition of NV Energy.[74] MidAmerican Holdings is a Des Moines, Iowa-based energy company owned by Berkshire Hathaway.[75] NV Energy is a holding company that owns Nevada Power Company (Nevada Power) and Sierra Pacific Power Company (Sierra Pacific).[76] To complete the transaction, MidAmerican Holdings purchased the outstanding shares of NV Energy common stock at a 23% premium, for a total of $5.6 billion.[77] Concurrently with the transaction, NV Energy attempted to merge its subsidiaries, Nevada Power and Sierra Pacific.[78] NV Energy withdrew its application on March 14, 2014, due to changed circumstances.[79] NV Energy may re-submit its merger application but must first address the "changes in circumstance" that prompted it to withdraw its original merger application.[80] NV Energy recently began this process by (a) drafting regulations for Senate Bill 123,[81] (b) seeking NVPUC

72. Lost Revenue Adjustment Mechanism of NorthWestern Energy, Docket No. D2014.6.53, at 3 (Mont. Pub. Serv. Comm'n June 16, 2014).

73. *See, e.g.*, Anne Hedges, *Colstrip is Neither Cheap Nor Reliable*, RAVALLI REPUBLIC (June 25, 2014), http://ravallirepublic.com/news/opinion/viewpoint/article_54dfc2f6-fcd0-11e3-8f99-001a4bcf887a.html; Travis Kavulla, *Customers Shouldn't be Obliged to Bail Out Utilities*, BOZEMAN DAILY CHRONICLE (June 25, 2014), http://www.bozemandailychronicle.com/opinions/guest_columnists/article_2d21c6c4-fc7b-11e3-8a07-0019bb2963f4.html.

74. Joint Application of Nevada Power Co., Sierra Pacific Power Co., & MidAmerican Energy Holdings Co. for Approval of a Merger of NV Energy, Inc. with MidAmerican, No. 13-07021 (Nev. Pub. Util. Comm'n Nov. 6, 2013).

75. *Id.* at 2.

76. *Id.* at 1.

77. *MidAmerican Energy Holdings Company and NV Energy, Inc. Merger Complete*, MARKETWATCH (Dec. 19, 2013, 4:01 PM), http://www.marketwatch.com/story/midamerican-energy-holdings-company-and-nv-energy-inc-merger-complete-2013-12-19; Noah Buhayar et al., *Buffett's MidAmerican Expands West with $5.6 Billion Deal*, BLOOMBERG (May 30, 2013, 11:38 AM), http://www.bloomberg.com/news/2013-05-29/buffett-s-midamerican-to-buy-nv-energy-in-5-6-billion-deal-1-.html.

78. Letter from Elizabeth Elliot, Assoc. Gen. Counsel, Nev. Power Co., to Breanne Potter, Assistant Comm'n Sec'y, Pub. Util. Comm'n of Nev. (May 31, 2013).

79. Motion of NVE Utilities to Vacate Procedural Schedule, Extend Existing Financing Authority and Withdraw Application, Docket No. 13-05056, at 1-2 (Nev. Pub. Util. Comm'n Mar. 14, 2014).

80. *Id.* at 2.

81. Rulemaking to Address an Emissions Reduction and Capacity Replacement Plan and Other Matters Related Thereto in Accordance with Senate Bill 123, Docket No. 13-06023 (Nev. Pub. Util. Comm'n Feb. 18, 2014).

permission to participate in an energy imbalance market (EIM),[82] and (c) shifting Nevada Power towards renewable energy in compliance with Senate Bill 123.[83]

2. Rulemaking on Senate Bill 123

On June 26, 2013, the NVPUC opened a rulemaking that focused on the Emissions Reduction and Capacity Replacement Plan (ERCR Plan) required by Senate Bill 123.[84] Pursuant to Senate Bill 123, any electric utility primarily serving densely populated counties[85] must submit an ERCR Plan to the NVPUC that includes decreasing coal-fired electric generating capacity and increasing renewable energy facilities.[86] The increase in renewable energy facilities is to be obtained through a Request for Proposals (RFP) process wherein the utility seeks proposals from outside sources for the construction or acquisition of renewable energy facilities. A major question addressed during the rulemaking was whether an electric utility could respond to its own RFP. The NVPUC determined that a utility could respond to its own RFP, but the utility must use an independent evaluator to ensure fairness in evaluating responses.[87] As of May 5, 2014, discussions continue regarding independent evaluators and confidentiality issues associated with the RFP process.[88]

On May 1, 2014, Nevada Power submitted its ERCR Plan in compliance with Senate Bill 123, which involves retiring or eliminating 812 MW of coal-fired generating capacity and replacing that capacity with 572 MW of natural gas and solar generating capacity.[89] The ERCR Plan also contains a renewable energy RFP schedule for 2014, 2015, and 2016 that will keep Nevada Power in compliance with Senate Bill 123's requirement that Nevada Power "construct or acquire 50 MW" of company-owned renewable energy by December 31, 2017.[90] The ERCR Plan also includes the construction of a solar facility that will generate

82. Joint Application of Nevada Power Co. & Sierra Pacific Power Co. for Approval of Amendments to Their Energy Supply Plans to Reflect Participation in the Energy Imbalance Market, Docket No. 14-04024 (Nev. Pub. Util. Comm'n Apr. 16, 2014).

83. Application of Nevada Power Co. Seeking Acceptance of the First Amendment to its 2013-2032 Integrated Resource Plan and its Energy Supply Plan Update for 2015, Docket No. 14-05003 (Nev. Pub. Util. Comm'n May 1, 2014).

84. Rulemaking to Address an Emissions Reduction and Capacity Replacement Plan and Other Matters Related Thereto in Accordance with Senate Bill 123, Docket No. 13-06023 (Nev. Pub. Util. Comm'n Feb. 18, 2014).

85. The category of "densely populated counties" currently includes only Clark County, which means that Nevada Power must comply with this statute, but Sierra Pacific remains unaffected. S.B. 123, 2013 Leg., 77th Sess. (Nev. 2013).

86. *Id.*

87. Rulemaking to Address an Emissions Reduction and Capacity Replacement Plan and Other Matters Related Thereto in Accordance with Senate Bill 123, Docket No. 13-06023 (Nev. Pub. Util. Comm'n Feb. 18, 2014).

88. NEV. PUB. UTIL. COMM'N, PHASE II PORTION OF DOCKET NO. 13-06023: TWO INFORMAL STAKEHOLDER MEETINGS at 3-4 (2014).

89. Application of Nevada Power Co. Seeking Acceptance of the First Amendment to its 2013-2032 Integrated Resource Plan and its Energy Supply Plan Update for 2015, Docket No. 14-05003 at 3-4 (Nev. Pub. Util. Comm'n May 1, 2014).

90. *Id.* at 2.

fifteen MW of renewable energy.[91] The ERCR Plan does not discuss the acquisition of the remaining thirty-five MW of renewable energy required by Senate Bill 123.

3. Energy Imbalance Markets (EIM)

On April 16, 2014, Nevada Power and Sierra Pacific submitted a joint application to the NVPUC seeking permission to participate in an EIM run by the California Independent System Operator (Cal ISO).[92] Before it can participate in the EIM, NV Energy needs the NVPUC to certify that NV Energy's plan to participate is "prudent" as defined in Nevada Administrative Code section 704.9494.[93] The NVPUC conditionally approved the application at its August 27, 2014 meeting.[94]

F. New Mexico

1. Regional Haze

In 2012, New Mexico Governor Susana Martinez asked the Public Service Company of New Mexico (PNM), the EPA, and New Mexico Environment Department to resolve the "haze" dispute involving the San Juan Generation Station (SJGS) in the Four Corners area.[95] The SJGS contains four generating units that each consists of boilers that burn coal to create steam and turbine generators that convert steam's heat energy into electricity.[96] On April 30, 2014, the EPA publicly approved the New Mexico Environment Department's and PNM's Revised State Implementation Plan (Revised SIP) to comply with federal emission standards of the Clean Air Act (CAA).[97]

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91. *Id.* at 5.

92. Joint Application of Nevada Power Co. & Sierra Pacific Power Co. for Approval of Amendments to Their Energy Supply Plans to Reflect Participation in the Energy Imbalance Market, Docket No. 14-04024 at 1 (Nev. Pub. Util. Comm'n Apr. 16, 2014). An Energy Imbalance Market (EIM) is a wholesale competitive energy market that allows utilities to manage supply-demand imbalances in real-time.

93. *Id.* at 8.

94. NEV. PUC, MINUTES OF THE PUBLIC UTIL. COMM'N AGENDA, AGENDA 16-14 (Aug. 27, 2014), *available at* http://pucweb1.state.nv.us/PDF/AXImages/Agendas/16-14/5374.pdf.

95. Dan Mayfield, *EPA Supporting Plan to Close Two PNM Plants*, ALBUQUERQUE BUS. FIRST (Apr. 30, 2014, 2:47 PM) [hereinafter Mayfield], http://www.bizjournals.com/albuquerque/news/2014/04/30/epa-supporting-plan-to-close-two-pnm-plants.html?page=all; Damon Scott, *Regional Haze Dispute Goes to Federal Court*, ALBUQUERQUE BUS. FIRST (Oct. 23, 2012, 6:19 AM), http://www.bizjournals.com/albuquerque/blog/morning-edition/2012/10/regional-haze-dispute-goes-to-federal.html.

96. U.S. ENVTL. PROT. AGENCY, OFFICE OF AIR QUALITY PLANNING & STANDARDS, AVAILABLE AND EMERGING TECHNOLOGIES FOR REDUCING GREENHOUSE GAS EMISSIONS FROM COAL-FIRED ELECTRIC GENERATING UNITS 5–8 (2010), *available at* http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf; *Generating Unit Definition*, ENERGYVORTEX.COM, http://www.energyvortex.com/energydictionary/generating_unit.html. ("A generating unit consists of the sum and total of all equipment necessary for production of electricity. In a coal-fired power plant, a generating unit normally consists of one or more boilers where coal is burned to create steam, plus one or more turbine generators that convert steam's heat energy into electricity.").

97. Application of Public Service Company of New Mexico for Approval to Abandon San Juan Generating Station Units 2 and 3, Issuance of Certificates of Public Convenience and Necessity for Replacement Power Resources, Issuance of Accounting Orders and Determination of Related Ratemaking Principles and

PNM's Revised SIP, which the New Mexico Public Regulation Commission (NMPRC) must approve, includes several components. One component will retire PNM's coal-fired power-generating Units 2 and 3 at the SJGS and require installation of pollution-control equipment on SJGS Units 1 and 4.[98] Another component involves the request for cost recovery of the underappreciated investment in SJGS Units 2 and 3 and the installation of selective non-catalytic reduction (SNCR) for SJGS Units 1 and 4 in an amount not to exceed $82 million.[99] In addition, PNM requests an order declaring that PNM prudently and reasonably incurred these costs to comply with the CAA and, as a result, may include these costs in a future rate case.[100]

PNM's Revised SIP also addresses the need for alternative energy. Retirement of SJGS Units 2 and 3 will reduce SJGS' capacity, requiring PNM to replace approximately 340 MW of generation with alternative generation sources to sustain customer demand.[101] In PNM's Revised SIP, PNM requests that the NMPRC issue certificates of public convenience and necessity (CCNs) that approve replacing the SJGS' lost generation with alternative nuclear, solar, wind and natural gas energy sources, as well as additional coal-fired generation from SJGS Unit 4.[102]

Several entities filed responses to PNM's application, advocating for an alternative that would prevent the NMPRC from considering PNM's request to replace lost capacity with additional coal-fired generation from SJGS Unit 4 and require supplemental testimony on PNM's other proposals for alternative capacity.[103] On June 11, 2014, the NMPRC extended the procedural schedule and ordered PNM to file supplemental testimony addressing the additional coal-fired energy from SJGS Unit 4 and PNM's "plans for replacement resources."[104]

2. SunZia

Multiple energy companies and associations sponsored the SunZia Southwest Transmission Project (SunZia), which consists of two bi-directional, extra-high voltage, electric transmission line and substations that will transport energy from Arizona and New Mexico to customers and markets across the desert

Treatment, Case No. 13-00390-UT, at 2 (N.M. Pub. Regulation Comm'n Dec. 20, 2013) [hereinafter PNM Application]; Mayfield, *supra* note 95; *see also Approval and Promulgation of Implementation Plans; New Mexico; Regional Haze and Interstate Transport Affecting Visibility State Implementation Plan Revisions; Withdrawal of Federal Implementation Plan for the San Juan Generating Station*, 79 Fed. Reg. 26,909 (proposed May 12, 2014) (to be codified at 40 C.F.R. pt. 52).

98. PNM Application, *supra* note 97, at 1-2.

99. *Id.* at 2.

100. *Id.*

101. *Id.* at 10-11.

102. *Id.* at 2.

103. Among these entities and organizations are: New Mexico Indep. Power Producers, W. Resource Advocates, Coalition for Clean Affordable Energy, Albuquerque Bernalillo County Water Util. Auth., New Mexico Indus. Energy Consumers, New Energy Economy, and the Staff of the Util. Div. of the Comm'n. Order Partially Granting PNM Motion, as Supplemented, for Leave to File Supplemental Testimony, to Extend Procedural Schedule and for Shortened Response Time and Denying PNM Motion for Leave to File Reply in Support of Motion for Leave to File Supplemental Testimony at 4-6, Case No. 13-00390-UT (N.M. Pub. Regulation Comm'n June 11, 2014).

104. *Id.* at 8.

Southwest.[105] Because part of this line is near the United States military's White Sands Missile Range (WSMR) site, concerns were raised as to whether the SunZia project would interfere with the United States military's ability to test long-range, live-fire weapons at the WSMR facility.[106] Congress and the Department of Defense (DOD) requested a Massachusetts Institute of Technology (MIT) study to determine whether the concerns were merited.[107] In March 2014, MIT released its report to Congress expressing that the concerns were reasonable and citing three points that may harm the WSMR: (1) vertical obstruction, (2) falling debris, and (3) possible electromagnetic interference.[108] On May 27, 2014, United States Senator for New Mexico, Martin Heinrich, announced that the DOD, SunZia, and the Bureau of Land Management had reached a resolution to permit the SunZia transmission line to cost-effectively operate alongside the WSMR.[109] The compromise requires that five miles of the SunZia transmission line near the WSMR be underground.[110]

3. Tri-State Generation and Transmission Association (Tri-State)

In 2000, New Mexico passed legislation providing that, if three or more New Mexico member utilities protest proposed rates, the generation and transmission cooperative files with the NMPRC, and the NMPRC "determines there is just cause in at least three of the protests for reviewing the proposed rates, [then] the [NMPRC] shall suspend the rates, conduct a hearing concerning reasonableness of the proposed rates and establish reasonable rates."[111] On September 10, 2013, Tri-State filed its notice to implement new rates with the NMPRC that would take effect on January 1, 2014.[112] On September 27 and 30, 2013, this legislation was triggered for the first time when four New Mexico Tri-State member utilities (Continental Divide Electric Cooperative, Jemez Mountains Electric Cooperative, Kit Carson Electric Cooperative, and Springer Electric Cooperative) protested Tri-State's proposed rates.[113] On December 11, 2013, the NMPRC suspended Tri-

105. *Project Information*, SUNZIA, http://www.sunzia.net/project_information.php (last visited Oct. 2, 2014) (explaining the details of the SunZia Southwest Transmission Project).

106. Terrance Vestal, *MIT Report: SunZia Electric Line Would Interfere with White Sands Missile Range*, EL PASO SUN-NEWS (Mar. 13, 2014, 12:00 AM), http://www.elpasotimes.com/news/ci_25333182/report-electric-line-would-interfere-wsmr.

107. Milan Simonich, *MIT to Study Proposed $1.2 Billion SunZia Project Opposed By WSMR*, LAS CRUCES SUN-NEWS (Nov. 15, 2013, 3:24 PM), http://www.lcsun-news.com/las_cruces-news/ci_24533003/mit-study-proposed-1-2-billion-sunzia-project.

108. *Id.* Neither MIT nor Congress made the MIT report available for the public. *Id. See also Pearce: MIT Study Validates Concerns over SunZia*, WASH. TIMES (Mar. 12, 2014), http://www.washingtontimes.com/news/2014/mar/12/pearce-mit-study-validates-concerns-over-sunzia/; Vestal, *supra* note 106.

109. Steve Ramirez, *Compromise Reached to Allow SunZia Line to be Built on WSMR Land*, LAS CRUCES SUN-NEWS (May 27, 2014, 2:32 PM), http://www.lcsun-news.com/las_cruces-news/ci_25844136/defense-department-offers-compromise-sunzia-project.

110. *Id.*

111. N.M. STAT. ANN. § 62-6-4(D) (2014).

112. Tri-State Generation and Transmission Ass'n, Inc. Advice Notice No. 19 and Accompanying Rate Schedules, Case No. 13-00321-UT (N.M. Pub. Regulation Comm'n Sept. 10, 2013).

113. Tri-State Generation and Transmission Ass'n, Inc.'s Response to Protests of Wholesale Rates, Case No. 13-0321-UT (N.M. Pub. Regulation Comm'n Nov. 4, 2013).

State's 2014 rates and denied reconsideration after oral arguments on January 29, 2014.[114] On March 5, 2014, the NMPRC appointed a mediator to assist in resolving the dispute between Tri-State and the four protesting New Mexico member utilities.[115] As of June 26, 2014, after multiple mediation sessions, the parties had not reached a resolution.[116] An evidentiary hearing will begin on January 5, 2015.[117]

In addition to this protest dispute, on January 25, 2013, Tri-State sued the NMPRC in the District Court for the District of New Mexico for declaratory and injunctive relief.[118] Because Tri-State sells electricity to member distribution cooperatives and public power districts in Colorado, Nebraska, New Mexico, and Wyoming, Tri-State asserted that the NMPRC does not have jurisdiction over Tri-State's ability to set rates in New Mexico and that the NMPRC's supervisory authority under New Mexico Statutes section 62-6-4(d) "impermissibly regulates interstate commerce in violation of the Commerce Clause of the United States Constitution . . . ."[119]

G. Washington

On April 29, 2014, Washington Governor Jay Inslee signed Executive Order 14-04 (EO 14-04), the Washington Carbon Pollution Reduction and Clean Energy Action.[120] EO 14-04 explains that Washington and other west coast states joined the Pacific Coast Collaborative (PCC), proposes several ways to comply with the PCC, and requires an annual compliance report by November 2014.[121] Specifically, EO 14-04 proposes that (1) the Carbon Emissions Reduction Taskforce provide recommendations by November 21, 2014, to discuss execution of the carbon emission limits and market mechanisms program;[122] (2) state agencies work with state utilities to reduce coal-fired electricity use, as well as improve their operations to reduce emissions;[123] (3) clean transportation, as well

114. Order Suspending Advice Notice No. 19's Rate Schedules, Case No. 13-0321-UT (N.M. Pub. Regulation Comm'n Dec. 11, 2013).

115. Order Granting Joint Motion to Appoint a Mediator, Case No. 13-0321-UT (N.M. Pub. Regulation Comm'n Mar. 5, 2014).

116. Order Holding Procedural Schedule in Abeyance and Setting Deadline for Responses, Case No. 13-0321-UT (N.M. Pub. Regulation Comm'n June 26, 2014).

117. Order Amending Procedural Schedule at 3, Case No. 13-0321-UT (N.M. Pub. Regulation Comm'n May 30, 2014).

118. Verified Complaint for Declaratory and Injunctive Relief, Tri-State Generation & Transmission Ass'n v. N.M. Pub. Regulation Comm'n, No. 13-cv-85 (filed D.N.M. Jan. 25, 2013).

119. *Id.*

120. State of Washington, Office of the Governor, Exec. Order 14-04 (2014) [hereinafter Exec. Order. 14-04].

121. *Id.*; MEMORANDUM OF UNDERSTANDING BETWEEN THE STATE OF WASHINGTON AND THE PROVINCE OF BRITISH COLUMBIA ON PACIFIC COAST COLLABORATION TO PROTECT OUR SHARED CLIMATE AND OCEAN, PACIFIC COAST COLLABORATIVE (2008), *available at* http://www.pacificcoastcollaborative.org/Documents/wabcpcc.pdf. The PCC calls for West Coast actions on climate leadership, clean transportation, and clean energy infrastructure. Through this agreement, Washington is required to establish carbon reduction programs that are already implemented in California and British Columbia to achieve greenhouse gas reduction to 1990 levels. *See generally id.*

122. Exec. Order 14-04, *supra* note 120, at 2-3.

123. *Id.* at 4, 7.

as a plan to improve transportation efficiency, be developed;[124] and (4) clean technology, including new renewable energy and energy efficiency technologies improving how citizens work and live, be developed.[125]

H. *Wyoming*

1. Baseline Groundwater Testing Rules

On November 14, 2013, the Wyoming Oil and Gas Conservation Commission (WYOGCC) adopted new rules, effective March 1, 2014, which require companies to perform baseline groundwater testing both before and after drilling a new well.[126] Under the new rules, when oil and gas operators apply for a permit to drill a new oil or gas well, they must identify all water sources within a half-mile of the surface location of the proposed oil well, gas well, coal-bed methane well, dedicated injection well, or WYOGCC-approved monitoring well.[127] Groundwater sources that must be tested include domestic, stock, industrial, municipal, or irrigation water wells or springs.[128] The rules require three rounds of testing; the initial test must occur in the twelve-month period prior to spudding the well, while the two subsequent tests must be between twelve and twenty-four months and thirty-six to forty-eight months after setting the production casing or liner.[129] Landowners must consent to oil and gas operators testing the water source and having the analytical test results and spatial coordinates of the water source made publicly available.[130]

Oil and gas operators must test groundwater extensively for temperature, pH, oxidation-reduction potential, specific conductance, turbidity, dissolved oxygen, total dissolved solids, dissolved gases, alkalinity, major anions and cations, presence of bacteria, total petroleum hydrocarbons, BTEX compounds, naphthalene, and other elements.[131] Operators are also required to notify the WYOGCC Supervisor, the Director of the Wyoming Department of Environmental Quality, and the water source's owner within twenty-four hours if test results reveal specific gases or compounds above allowable levels.[132] The exact sampling, analysis, evaluation, and reporting requirements and protocols are located in Appendix K of the WYOGCC's rules.[133]

These rules do not apply to existing oil or gas wells that are converted into injection wells for enhanced recovery or disposal purposes.[134] Operators may request a variance from these requirements by filing a Sundry Notice with the WYOGCC if there are no water sources located within a half-mile radius of the

124. *Id.* at 4-5.
125. *Id.* at 5-6.
126. Proposed Rules, Groundwater Baseline, Cause No. 12, Order No. 2, Docket No. 477-2013 (Wyo. Oil & Gas Conservation Comm'n Nov. 12, 2013).
127. Wyo. Oil & Gas Conservation Comm'n, General Comm'n Rules, Ch. 3, § 8(c)(iii).
128. *Id.* §§ 2(e), (hhh).
129. *Id.* § 46(e).
130. *Id.* § 2(e).
131. *Id.* § 46(h).
132. *Id.* §§ 46(c)(iii), (j).
133. *Id.* § 46(f).
134. *Id.* § 46(a).

proposed well, if all available water sources are improperly maintained, or if the owner of the water source declines to grant access despite an operator's "reasonable efforts" to obtain consent to conduct sampling.[135]

2. Fracking Regulation

On March 12, 2014, the Wyoming Supreme Court reversed and remanded a case related to the confidentiality of the chemicals and ingredients in fracking fluids.[136] The case stems from a WYOGCC rule passed in 2010 that requires oil and gas operators to declare and file a list of chemicals and other ingredients in their fracking fluids, and an exception that allows the WYOGCC Supervisor to classify these documents as "trade secrets" upon request from an oil and gas operator, thereby preventing public disclosure of the documents under Wyoming's Public Records Act (WPRA).[137] In 2012, after the WYOGCC Supervisor denied a request for documents related to fracking chemicals, the Powder River Basin Resource Council and other environmentalist groups filed a petition to review the Supervisor's trade secret determination under the Wyoming Administrative Procedure Act (WAPA).[138] This denial made its way before the Wyoming Supreme Court, which ruled that the environmental groups should have challenged the WYOGCC Supervisor's determination using the procedures set forth under the WPRA rather than the WAPA.[139] Holding that it was unable to review the trade secret determination because of this procedural issue, the court reversed and remanded the case to the district court for proceedings under the WPRA.[140] Although the court made no rulings related to the WYOGCC rule or whether fracking ingredients are rightfully classified as trade secrets, it explicitly adopted the federal Freedom of Information Act's definition of a "trade secret" for use in this case and similar challenges in the future.[141]

3. Wyoming Infrastructure Authority (WIA)

On March 10, 2014, Wyoming Governor Matt Mead signed House Bill No. 0147, which expands the WIA's duties from electricity infrastructure to "electric and energy transmission infrastructure" effective July 1, 2014.[142] Created by the State's legislature in 2004, the WIA is tasked with diversifying and expanding the Wyoming economy through improvements in the state's electric transmission infrastructure.[143] The WIA's authority includes planning, financing, constructing, and developing facilities and structures related to electric and energy transmission as well as planning and establishing corridors for the transmission of electricity.[144]

135. *Id.* § 46(d).

136. Powder River Basin Res. Council v. Wyo. Oil & Gas Conservation Comm'n, 320 P.3d 222 (Wyo. 2014).

137. *Id.* at 225.

138. *Id.* at 228.

139. *Id.* at 230.

140. *Id.*

141. *Id.* at 232-34.

142. WYO. LEG. 55 (2014), 2014 Wyoming Laws Ch. 55 (H.B. 147); WYO. STAT. ANN. § 37-5-302 (2013).

143. WYO. STAT. ANN. § 37-5-303(a) (2013).

144. *Id.* § 37-5-304.

The change gives the WIA a greater role in the state's coal infrastructure, expanding the WIA's responsibilities to include "distribution facilities, including ports."[145]

II. SOUTH

A. Georgia

In accordance with the three-year accounting order and stipulation reached in its 2010 rate case, Georgia Power Company (GPC) filed its 2013 rate case with the Georgia Public Service Commission (GPSC) on June 28, 2013.[146] GPC's requested $485.2 million increase includes $336.6 million through traditional base tariffs, $132.3 million through the Environmental Compliance Cost Recovery tariff, $5.3 million through the Demand Side Management tariffs and $11 million through the Municipal Franchise Fee tariff.[147] GPC requested an authorized return on equity range of 10.25% to 12.25% with a midpoint of 11.50%.[148] The parties reached a settlement agreement for a three-year rate plan, which the GPSC approved without modification.[149] The settlement agreement authorized GPC to increase base rates by $110 million in 2014, with step increases of $187 million and $170 million in 2015 and 2016, respectively.[150] GPC's authorized return on equity was set at 10.95%, with an earnings band of 10.0% to 12.0% and a sharing mechanism providing that two-thirds of any earnings above the band will be returned to customers.[151]

B. Louisiana

1. City Council Resolution R-13-17

In Resolution R-08-295, the City Council of New Orleans (Council) commenced a rulemaking proceeding to develop Integrated Resource Planning (IRP) components and IRP reporting requirements for Entergy New Orleans, Inc. (ENO), intended to provide a framework to guide ENO's decisions including future generation resources, the development and deployment of demand-side resource options, and the incorporation of energy efficiency programs into ENO's planning process.[152] On October 30, 2012, ENO submitted its second triennial IRP Filing.[153] The Council, in Resolution R-13-17, established a procedural schedule for considering ENO's 2012 IRP including directives for ENO to: (1)

145. WYO. LEG. 55 (2014), 2014 Wyoming Laws Ch. 55 (H.B. 147).

146. Georgia Power Co. 2013 Rate Case, Ron Hinson Pre-Filed Testimony, Docket No. 36989, at 2 (June 28, 2013).

147. *Id.* at 3.

148. *Id.* at 3-4, 12.

149. Georgia Power Co. 2013 Rate Case, Order Adopting Settlement Agreement, Docket No. 36989 (Dec. 17, 2013).

150. *Id.* at 6, 9, 18.

151. *Id.* at 5, 13, 18.

152. Resolution and Order Considering the 2012 Integrated Resource Plans of Entergy New Orleans, Inc. and Entergy Louisiana, LLC and Extending Energy Smart New Orleans Energy Efficiency Programs, Resolution R-13-363, Docket No. UD-08-02, at 2-3 (Oct. 10, 2013) [hereinafter Resolution R-13-363].

153. *Id.* at 6.

conduct a public technical conference on the 2012 ENO IRP; (2) make a supplemental implementation and cost recovery filing for future energy efficiency and Demand-Side Management (DSM) programs contained in their IRP filings; and (3) file responsive comments to any intervenor comments.[154] Subsequent to ENO's compliance with the Council's directives, on September 6, 2013, the Council's Utility Advisors filed a report of their assessment of ENO's 2012 IRP filings.[155] On October 10, 2013, the Council adopted Resolution R-13-363, finding that: (1) ENO's 2012 IRP Filing complied with the Council's IRP requirements; (2) ENO should comply with specific recommendations regarding its IRP Action Plan; and (3) it is in the public interest to provide the necessary funding to continue the existing energy efficiency programs to assure continuity of energy efficiency programs in New Orleans through the end of calendar year 2014.[156]

In addition, the Council directed its Utility Advisors to provide draft recommendations to the Utility Committee for determination of the appropriate level of DSM programs in the city, considering "the rate effects of [any] cost recovery mechanisms, ultimate DSM program kWh savings, DSM goals, incentives, and specific DSM program implementation."[157]

Further, the Council adopted an incentive mechanism that rewards the utility for meeting established energy savings targets and penalizes it at 5% of the program costs if it does not meet the Council's energy savings targets.[158] The Council also directed ENO and Entergy Louisiana, LLC (ELL) to file, within 120 days of the adoption of this resolution, decoupling proposals for subsequent consideration by the Council.[159] With regard to their next triennial IRP filing, the Council directed ENO and ELL to include an evaluation of demand response programs involving load control of customer appliances and time-differentiated rates as well as other demand response programs, including all programs available as a result of any Midcontinent Independent System Operator (MISO) tariffs. Similarly, ENO was directed to file, in its next triennial IRP filing, a gas energy efficiency potential study for consideration by the Council in a subsequent docket.

2. City Council Resolution R-14-224

On June 5, 2014, the Council adopted a resolution directing ENO to implement several key improvements to its IRP process in connection with its next triennial IRP filing in October 2015.[160] The improvements in question had been identified by the Council in Resolution R-13-363 as a part of the review of ENO's 2012 IRP filing.[161] Generally, the Council directed ENO to make the IRP process

154. *Id.* at 9.

155. *Id.* at 10.

156. *Id.* at 57.

157. Resolution R-13-363, *supra* note 152, at 60.

158. *Id.* at 61.

159. *Id.* at 63.

160. Resolution and Order Establishing Guidance for Entergy New Orleans, Inc.'s 2015 Triennial Integrated Resources Plan Filing, Resolution R-14-224, Council Docket No. UD-08-02 (June 5, 2014) [hereinafter Resolution R-14-224].

161. Resolution R-13-363, *supra* note 152, at 57-58.

more transparent and to elicit greater stakeholder participation.[162] In addition, the Council approved ENO's proposed methodologies for calculating transmission line losses for energy and capacity.[163] Other IRP improvements approved by the Council include changes to the cost-benefit tests used in the IRP modeling process, and the appropriate avoided cost calculation to be used in ENO's next triennial IRP filing.[164]

3. Prudence Investigation

On November 21, 2013, the Council initiated "an investigation and evidentiary hearing into the prudence and reasonableness of the shortening of the System Agreement termination notice provision and the resulting impact of that decision on New Orleans ratepayers."[165] The Entergy System Agreement is a contract among the Entergy Operating Companies[166] and Entergy Services, Inc. Under the System Agreement, the Entergy Operating Companies have collectively planned and operated their electric generation and bulk transmission facilities as a single, integrated electric system for over fifty years.[167]

The presidents of both ENO and ELL are voting members of the Entergy System Operating Committee.[168] On September 10, 2013, the Entergy System Agreement Operating Committee "voted in favor of a proposal to amend the termination notice period" provided in the System Agreement from ninety-six months to sixty months.[169] The Council in its resolution expressed its concern that "the reduction of the termination notice period from the System Agreement may be detrimental to New Orleans ratepayers and, specifically, may significantly reduce or eliminate many of the benefits that accrue to New Orleans ratepayers under the Settlement Agreement."[170]

C. Kentucky

1. Kentucky Power Company (Kentucky Power)

On October 7, 2013, the Kentucky Public Service Commission (KYPSC) approved Kentucky Power's application to acquire an undivided 50% interest in the Mitchell Generating Station previously owned by an affiliate, Ohio Power Company.[171] The companies' parent, American Electric Power, received approval

162. Resolution R-14-224, *supra* note 160, at 15-18.

163. *Id.* at 10-12.

164. *Id.* at 7-9, 13-15.

165. Resolution Initiating a Prudence Investigation of Entergy New Orleans, Inc.'s and Entergy Louisiana LLC's Agreement to Shorten the Termination Notice Period of the System Agreement, Resolution R-13-432, Council Docket No. UD-13-03 (Nov. 21, 2013).

166. *Id.* at 1. The Entergy Operating Companies are: Entergy Arkansas, Inc. (EAI); Entergy Gulf States Louisiana, LLC (EGSL); Entergy Louisiana, LLC (ELL); Entergy Mississippi, Inc. (EMI); Entergy New Orleans, Inc. (ENO); and Entergy Texas, Inc. (ETI). *Id.*

167. *Id.* at 2.

168. *Id.* at 3.

169. *Id.* at 4.

170. *Id.*

171. Application of Kentucky Power Company for (1) A Certificate of Public Convenience and Necessity Authorizing the Transfer to the Company of an Undivided 50% Interest in the Mitchell Generating Station and

from several jurisdictions to separate its Ohio generation assets from its Ohio distribution and transmission operations and to transfer the generation assets to Kentucky Power and other regulated affiliates. Kentucky Power had recently withdrawn an application with the KYPSC to retrofit its Big Sandy 2 Generation Unit to comply with recent and pending environmental regulations because of the high retrofitting cost; the KYPSC found acquisition of the Mitchell Generating Station to be the least-cost alternative.[172]

2. Smelters

Following notices that the Sebree and Hawesville smelters would close unless provided access to wholesale power markets, Century Sebree, Century Aluminum, Big Rivers Electric Corporation (Big Rivers), and one of its three distribution cooperative members, Kenergy Corporation (Kenergy), negotiated special power contracts for the provision of wholesale service.[173] The KYPSC approved the contracts, which provide that Big Rivers, as the designated agent for the smelters, will acquire electricity on the wholesale power market for Kenergy to resell to Century Sebree and Century Aluminum, instead of supplying Kenergy with electricity from Big Rivers' generation facilities, which were built to serve the native load customers of its distribution cooperative members.[174]

With the special contracts and reduced load from Century Aluminum's Hawesville smelter, Big Rivers announced its plan to idle the Kenneth C. Coleman Power Station (435 MW) (Coleman) in Hawesville, Kentucky.[175] In addressing an issue of first impression, the KYPSC allowed Big Rivers to continue recording Coleman's depreciation expense after it is idled; permitted Big Rivers was directed to record depreciation expense as a deferred asset.[176] However, the KYPSC stated its intention to consider the recorded amount at a later time if Coleman is sold, closed, or needed to meet energy demands.[177] The KYPSC later granted a request for rehearing to address the System Support Resource Agreement filed with the FERC by MISO concerning the operation of Coleman.[178]

Associated Assets; (2) Approval of the Assumption by Kentucky Power Co. of Certain Liabilities in Connection with the Transfer of the Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral of Costs Incurred in Connection with the Company's Efforts to Meet Federal Clean Air Act and Related Requirements; and (5) All Other Required Approvals and Relief, Case No. 2012-00578, Order (Ky. Pub. Serv. Comm'n Oct. 7, 2013).

172. *Id.* at 7.

173. Joint Application of Kenergy Corp. and Big Rivers Elec. Corp. for Approval of Contracts and for a Declaratory Order, Case No. 2013-00221, at 26 (Ky. Pub. Serv. Comm'n Aug. 14, 2013) [hereinafter Case No. 2013-00221]; Joint Application of Kenergy Corp. and Big Rivers Elec. Corp. for Approval of Contracts and for a Declaratory Order, Case No. 2013-00413, at 5 (Ky. Pub. Serv. Comm'n Jan. 30, 2014) [hereinafter Case No. 2013-00413].

174. Case No. 2013-00221, *supra* note 173, at 6, 27; Case No. 2013-00413, *supra* note 173, at 6, 20.

175. Application of Big Rivers Elec. Corp. for an Adjustment of Rates, Case No. 2013-00535, at 3-4 (Ky. Pub. Serv. Comm'n Oct. 29, 2013).

176. *Id.* at 31-33.

177. *Id.* at 33.

178. Application of Big Rivers Elec. Corp. for an Adjustment of Rates, Case No. 2012-00535 (Ky. Pub. Serv. Comm'n July 24, 2014).

D. Mississippi

1. Quick Start Energy Efficiency Plans

On January 10, 2014, Mississippi Power Company (Mississippi Power) and Entergy Mississippi, Inc. (Entergy Mississippi) filed for approval of their respective Quick Start Energy Efficiency Plans.[179] These plans were filed pursuant to the Mississippi Public Service Commission's (MSPSC) Rule 29, which was passed in 2013 and requires electric and gas utilities within the MSPSC's jurisdiction to implement energy efficiency programs and standards to promote the efficient use and conservation of electricity and natural gas.[180] The proposed plans include programs to install energy efficient lighting for residential customers, provide energy audits to educate residential customers about home energy usage and energy saving products, and provide financial incentives for large commercial and industrial customers to make efficient purchase choices.[181] MSPSC approved these plans June 3, 2014.[182]

2. Entergy Mississippi

On June 10, 2014, Entergy Mississippi filed its first general rate case in nearly twelve years with the MSPSC, proposing an increase in rates that would result in the collection of an additional approximately $49 million from customers during calendar year 2015 to recover infrastructure investments, non-fuel operating and maintenance (O&M) expenses, average fuel and purchased power expenses, and a return to shareholders on the capital they invested. [183] Entergy Mississippi also proposed a modernized formula rate plan incorporating a forward test year and modifications to its riders to reflect joining MISO and its forthcoming exit from participation in the Entergy System Agreement.[184] As of October 4, 2014, the proposed rate has not yet been approved by the MSPSC.

3. House Bill 844

On July 1, 2014, House Bill 844 went into effect in Mississippi exempting certain agricultural businesses from state sales tax on electric and natural gas service bills.[185] The exemption, which was part of an effort to lower utility costs for Mississippi's agricultural industry, applies:

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179. Application for Approval of Quick Start Energy Efficiency Portfolio Plan, Docket No. 2014-UA-6, at 1 (Miss. Pub. Serv. Comm'n Jan. 10, 2014) [hereinafter Docket No. 2014-UA-6]; Direct Testimony of Chad Ihrig on Behalf of Mississippi Power Co., Docket No. 2014-UN-10 (Miss. Pub. Serv. Comm'n Jan. 10, 2014) [hereinafter Ihrig Testimony].

180. Proposal of the Mississippi Pub. Serv. Comm'n to Possibly Amend Certain Rules and Regulations Governing Public Utility Service, Docket No. 2010-AD-2, at 2 (Miss. Pub. Serv. Comm'n July 11, 2013).

181. Docket No. 2014-UA-6, *supra* note 179, at 2-3; Ihrig Testimony, *supra* note 179, at 3-4.

182. Order Approving Quick Start Energy Efficiency Portfolio Plan, Docket No. 2014-UA-006 (Miss. Pub. Serv. Comm'n June 3, 2014).

183. Notice of Intent of Entergy Mississippi, Inc. to Modernize Rates to Support Economic Development, Power Procurement, and Continued Investment, Docket No. 2014-UN-132, at 2, 21 (Miss. Pub. Serv. Comm'n June 10, 2014).

184. *Id.* at 2.

185. H.B. 844, 2013 Reg. Sess. (Miss. 2013).

> [W]here energy is purchased from a utility to be used directly in the production of poultry or poultry products, livestock and livestock products, domesticated fish and domesticated fish products, marine aquaculture products, plants or food by commercial horticulturists, the processing of milk and milk products, the processing of poultry and livestock feed, or the irrigation of farm crops.[186]

E. Tennessee

Plains and Eastern Clean Line LLC (Plains/Eastern), a subsidiary of Clean Line Energy Partners, LLC (Clean Line), filed an application with the Tennessee Regulatory Authority for a CCN to construct, own, and operate a transmission facility in Tennessee to deliver wind power from Oklahoma to an interconnection with the Tennessee Valley Authority (TVA).[187] Plains/Eastern is currently developing a roughly 700-mile transmission system capable of delivering approximately 3,500 MW of renewable energy from Oklahoma to entities in the Southeast, Mid-South, and Tennessee; providing TVA and other wholesale customers additional access to renewable energy.[188] The proposed seventeen-mile Tennessee portion of the line would interconnect to TVA's Shelby Substation.[189]

F. Texas

In October 2013, the Public Utility Commission of Texas (PUCT) announced that transmission and distribution utilities (TDUs) "have applied to the [PUCT] to establish the costs of providing non-standard meters to customers instead of advanced meters now used by about 97% of the 6.6 million customers in the competitive electric markets of Texas."[190] Electric consumers "in areas with retail competition [can] choose a non-standard meter [so] long as the customer pays for all costs associated with non-standard meter use."[191] Applicable costs include "a one-time fee and a recurring monthly fee."[192] Compliance dockets and intervention deadlines were set for each TDU in November 2013.[193]

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186. Hope Cross, *Presley: Agricultural Exemption from Utility Sales Tax in Effect as of July 1st*, MONROE JOURNAL (July 3, 2014), http://monroecountyjournal.com/2014/07/03/presley-agricultural-exemption-utility-sales-tax-effect-july-1st/.

187. Petition of Plains and Eastern Clean Line LLC for a Certificate of Convenience and Necessity Approving a Plan to Construct a Transmission Line and to Operate as an Electric Transmission Public Utility, Docket No. 12-00036, at 1 (Tenn. Regulatory Auth. Apr. 4, 2014).

188. *Id.* at 3-4.

189. *Id.* at 4.

190. Press Release, Pub. Util. Comm'n of Tex., Plans Filed for Advanced Meter Opt-Out Costs: Electric Customers Have New Option in Competitive Markets (Oct. 25, 2013), *available at* http://www.puc.texas.gov/agency/resources/pubs/news/2013/102513.pdf.

191. *Id.*

192. *Id.*

193. *Id.*

III. MIDWEST AND PLAINS

A. Illinois

1. Ameren Transmission Company of Illinois (ATXI)

On August 20, 2013, the Illinois Commerce Commission (ILCC) authorized ATXI to construct a $1 billion, 345 kilovolt electric transmission line that will stretch from the Mississippi River to the border between Illinois and Indiana pursuant to sections 8-406.1 and 8-503 of the Illinois Public Utilities Act.[194]

The ILCC approved the "Stipulated Route" between the Mississippi River and Quincy, Illinois, which was endorsed by ATXI and certain intervenors in the course of the proceeding, in addition to the construction of the proposed substation.[195] The ILCC also approved the "hybrid" route, proposed by ILCC staff, for the segment from Quincy to Meredosia, Illinois, as well as the proposed substation.[196] The ILCC approved ATXI's construction of facilities along a "Stipulated Route" between Meredosia and Ipava, Illinois, but rejected ATXI's proposal to construct a new substation at Ipava.[197] The ILCC also authorized the construction of facilities from Meredosia to Pawnee, Illinois, along a "Stipulated Route" that was developed by certain parties in the course of the litigation, as well as the construction of a new substation in Pawnee.[198] While the ILCC did not authorize the construction of the facilities proposed from Pawnee to Pana, Illinois, noting that ATXI had not demonstrated that its preferred route was the least-cost alternative available,[199] the ILCC approved an intervenor-proposed route spanning from Pana to Kansas, Illinois.[200] Lastly, the ILCC approved a route from Kansas, Illinois to the Illinois-Indiana border, and from Sidney to Rising, Illinois, but found that ATXI's proposal to construct new substations adjacent to existing substations did not satisfy the least-cost requirement set forth in section 8-406.1 of the Illinois Public Utilities Act.[201]

The ILCC additionally criticized ATXI's decision to proceed under the expedited siting provisions of the Illinois Public Utilities Act, noting that ATXI neglected to provide a complete list of affected landowners in its initial filing, which led the ILCC to extend the deadline to provide newly identified landowners with an opportunity to be heard.[202] The ILCC also highlighted ATXI's refusal to withdraw certain segments from the proceeding to allow all parties more time to consider the more contentious aspects of the proposal.[203] The ILCC indicated that there is a "very real possibility that the expedited schedule for considering such a

194. Ameren Transmission Co. of Illinois, Docket No. 12-0598, (Ill. Commerce Comm'n Aug. 20, 2013) (citing 220 ILL. COMP. STAT. ANN. 5/8-406.1, 8-503 (West 2013)) [hereinafter Ameren Transmission Co. of Ill.].

195. *Id.* at 15-24.

196. *Id.* at 24-41.

197. *Id.* at 42-55.

198. *Id.* at 55-78.

199. Ameren Transmission Co. of Ill., *supra* note 194, at 83-84.

200. *Id.* at 84-100.

201. *Id.* at 100-29 (citing 220 ILL. COMP. STAT. ANN. 5/8-406.1).

202. *Id.* at 7-10.

203. *Id.* at 8.

massive project may result in less than optimal outcomes. Alternatives may be overlooked and shortcomings may be missed."[204]

2. Commonwealth Edison Company (ComEd)

On February 5, 2014, the ILCC approved ComEd's proposed Rider NAM–Non AMI Metering (Rider NAM), which applies to customers (1) who refuse to voluntarily allow ComEd to install advanced metering (AMI) at their premises in accordance with ComEd's AMI plan, and (2) whose premises ComEd is unable to gain access to for installation of AMI equipment.[205] The ILCC approved ComEd's proposal to provide customers that refuse installation of AMI a monthly meter reading service and to utilize a $21.53 monthly charge to recover some of the costs associated with providing that service.[206] The ILCC further approved ComEd's proposal to submit four reports over two years addressing the operation of Rider NAM, after which the ILCC stated it would consider whether "a different monthly meter reading charge is more appropriate."[207] Lastly, the ILCC approved ComEd's proposal to eliminate customers' ability to defer the installation of AMI "after the earlier of June 30, 2022, or one year after the date of the last AMI meter installation" provided under ComEd's AMI plan.[208]

B. Iowa

1. Jurisdiction over Solar Developers

On July 11, 2014, the Iowa Supreme Court upheld a PPA between Eagle Point Solar (EPS) and the City of Dubuque (the City) for the behind-the-meter sale of power by the kWh from solar power (photo voltaic) arrays.[209] The court held that such an arrangement was not sufficiently "clothed with the public interest" so as to transform EPS into a "public utility" or "electric utility" that would be prohibited by statute from making such sales within the exclusive service territory of Interstate Power and Light Company (IPL).[210]

In this case, EPS was "in the business of providing design, installation, maintenance, monitoring, operational, and financing assistance services" with respect to solar electric generation systems in Iowa.[211] Dubuque was interested in pursuing the development of a renewable energy resource in the form of an on-site solar power system to satisfy a portion of the electric power needs of a single city building within the exclusive electric service territory of IPL, and sought to enter into a long-term financing agreement with EPS to accomplish that goal.[212] EPS proposed to finance, install, own, operate, and maintain the solar system and

204. *Id.* at 10.
205. Commonwealth Edison Co., Docket No. 13-0552 (Ill. Commerce Comm'n Feb. 5, 2014).
206. *Id.* at 8-13.
207. *Id.* at 4.
208. *Id.* at 13-18.
209. SZ Enterprises, LLC v. Iowa Util. Bd., No. 13-0642, 2014 WL 3377074 (Iowa 2014).
210. *Id.* at *27.
211. *Id.* at *1.
212. *Id.* at *1-2.

charge Dubuque on a cents-per-kWh basis for the electric output.[213] Under the PPA, EPS would be entitled to incentives associated with the solar power system,[214] the building would continue to remain connected to the electric grid, and the City would continue to purchase electricity from IPL to satisfy some of the electric energy needs of the building.[215]

EPS petitioned the Iowa Utilities Board (IAUB) for a declaratory order determining that EPS was neither a "public utility" subject to regulation by the IAUB under Iowa law nor an "electric utility" subject to the exclusive service territory provisions of Iowa law.[216] On April 12, 2012, the IAUB issued an order finding that, under a bright-line test based solely on the fact that EPS proposed to sell electricity on a per-kWh-hour basis, EPS met the definitions of "public utility" and "electric utility."[217]

On judicial review of the IAUB's decision, the Iowa District Court held that the IAUB erred, finding that, under the authority of *Iowa State Commerce Commission v. Northern Natural Gas Co.*,[218] the IAUB should have applied an eight-factor test established by *Natural Gas Service Co. v. Serv-Yu Cooperative, Inc.*,[219] rather than the IAUB's bright-line single-factor test to determine whether EPS was acting as a "public utility."[220] Applying the eight-factor test, the Iowa District Court held that EPS was neither a "public utility" nor an "electric utility."[221]

On appeal from district court, a divided Iowa Supreme Court held (4-2) that: (1) the IAUB is not entitled to deference on this issue; (2) under a de novo review, the core issue is whether the transaction was sufficiently clothed in public interest to make EPS a "public utility;" and (3) that the resolution of this issue should be informed by the eight-factor test established in *Serv-Yu*.[222] In weighing these factors, the Iowa Supreme Court agreed with the district court and held that EPS would not be acting as a "public utility."[223] The court also held that under Iowa law, an entity that is neither a "public utility" nor a "city utility" is not an "electric utility" subject to the exclusive service territory provisions of Iowa law.[224]

213. *Id.* at *1.

214. *SZ Enterprises*, 2014 WL 3377074, at *1.

215. *Id.* at *2.

216. *Id.* at *1.

217. *Id.*

218. Iowa State Commerce Comm'n v. N. Natural Gas Co., 161 N.W.2d 111, 115 (Iowa 1968).

219. Natural Gas Serv. Co. v. Serv-Yu Coop., Inc., 219 P.2d 324, 325-26 (Ariz. 1950).

220. *SZ Enterprises*, 2014 WL 3377074, at *4; *Natural Gas Service Co.*, 219 P.2d at 325-26. The eight Serv-Yu factors are:

> (1) [w]hat the corporation actually does; (2) [a] dedication to public use; (3) [a]rticles of incorporation, authorization, and purposes; (4) [d]ealing with the service of a commodity in which the public has been generally held to have an interest; (5) [m]onopolizing or intending to monopolize the territory with a public service commodity . . . ; (6) [a]cceptance of substantially all requests for service . . . ; (7) [s]ervice under contracts and reserving the right to discriminate is not always controlling . . . ; and (8) [a]ctual or potential competition with other corporations whose business is clothed with the public interest.

Natural Gas Serv. Co., 219 P.2d at 325-326.

221. *SZ Enterprises*, 2014 WL 3377074, at *6.

222. *See generally id.*

223. *Id.* at *32.

224. *Id.* at *28-29.

2. MidAmerican Energy Company (MidAmerican)

On March 17, 2014, the IAUB issued a decision in a general rate case filed by MidAmerican.[225] It modified its decision in minor respects on rehearing in an order issued on July 10, 2014.[226] In its decisions, the IAUB abandoned the Average and Excess (A&E) method for allocating generation costs, which had been in place decades prior to this decision.[227] Under the A&E method, generational costs are allocated using "two measurements from each customer class;" specifically, "average demand and excess demand."[228] Instead, the IAUB approved MidAmerican's proposed Hourly Costing Model (HCM)[229] methodology, which "allocates or distributes fixed costs over all hours of the year using hourly load date from each customer class."[230] The stated basis for this change in methodology was the development of wind energy as a significant source of generation, which, unlike other generation, "is not built to meet peak demands."[231] The IAUB took the position that the A&E method "assumes that all generation is built to meet peak demand and also to provide reliable energy throughout the year" and that this assumption does not apply to wind energy that "is built primarily for environmental planning and low cost energy."[232] The IAUB did attempt, however, to limit the precedential effect of its decision by stating that the new approach may not be appropriate in the future or for any other Iowa utility.

C. Indiana

1. Legislation

In 2014, the Indiana General Assembly passed Senate Bill 340, which allows industrial customers of an electricity supplier to opt-out of certain energy efficiency programs implemented by the electricity supplier in response to an order of the Indiana Utility Regulatory Commission (INURC). While the legislation originally provided only for industrial opt-out, as amended and enacted the legislation also "provides that certain energy efficiency programs may not be renewed after December 31, 2014."[233] Under the legislation, "an electricity supplier may offer an energy efficiency program and, if authorized by the [INURC], recover associated costs."[234] The legislation also requires the INURC to provide a status report to the Indiana General Assembly's Regulatory Flexibility Committee and the Legislative Council by August 15, 2014, on energy efficiency programs implemented under INURC orders, including the effects on customers'

225. Press Release, Iowa Util. Bd., Docket No. RPU-2013-0004: MidAmerican Energy Company's Electric Rate Increase (Mar. 17, 2014), http://www.state.ia.us/iub/energy/MECE-RPU-2013-0004.html.

226. Order on Rehearing, Docket No. RPU-2013-0004 (Iowa Util. Bd. July 10, 2014).

227. Order Approving Settlement, with Modifications, and Requiring Additional Information, Docket No. RPU-2013-0004, at 82 (Iowa Util. Bd. Mar. 17, 2014).

228. *Id.* at 51.

229. *Id.* at 85.

230. *Id.* at 51.

231. *Id.* at 82-84.

232. *Id.* at 83.

233. S.B. 340, 118th Gen. Assemb., 2d Reg. Sess. (Ind. 2014), http://iga.in.gov/legislative/2014/bills/senate/340/ (last visited July 25, 2014).

234. *Id.*

rates and charges.[235] Indiana Governor Mike Pence allowed the legislation to become law without his signature and sent a letter regarding the legislation to the INURC.[236] Governor Pence requested that the INURC "make recommendations on DSM and [energy efficiency] policies and programs, so that they may serve as a framework . . . in the upcoming 2015 session of the Indiana General Assembly."[237]

2. INURC DSM Activity

On January 15, 2014, the INURC issued an order initiating an investigation into the development of an opt-out from the INURC's statewide generic DSM programs for certain large customers.[238] The INURC also opened a second phase of the proceeding to address any additional issues related to, or arising as a result of, the industrial customer opt-out provided for in SEA 340.[239]

3. New Indianapolis Power and Light Combined Cycle Gas Turbine Plant

The INURC issued an order approving Indianapolis Power and Light's (IPL) request for a CCN for the construction of a new combined cycle gas turbine (CCGT) plant and for the refueling of certain of its generating units.[240] The estimated cost of the project is $631 million.[241] While approving the petition, the INURC found that the return on equity should be 10.2%, instead of the 12.1% requested by IPL.[242] Additionally, the Commission discussed the utility's approach of its request for proposal process, expressing concerns over the utility's approach.[243]

D. Michigan

1. Customer Data

On October 17, 2013, the Michigan Public Service Commission (MIPSC) accepted proposed tariff provisions for Consumers Energy Company, DTE

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235. S.B. 340 Fiscal Impact Statement, Legis. Services Agency, Office of Fiscal and Management Analysis (Mar. 14, 2014).

236. Letter from Michael R. Pence, Governor of Ind., to James D. Atterholt, Chairman, Ind. Util. Regulatory Comm'n (Mar. 27, 2014), *available at* http://www.in.gov/iurc/files/Letter_from_Governor_Pence(1).pdf.

237. *Id.*

238. The Commission's Investigation into the Required Participation of Certain Large Customers in Jurisdictional Electric Utility Demand Side Management Programs and Any Associated Impacts on a Utility's Annual Energy Savings Goals Established in the Phase II Order in Cause No. 42693, Cause No. 44441 (Ind. Util. Regulatory Comm'n Jan. 15, 2014), *available at* http://www.in.gov/iurc/files/Large_customer_opt_out_investigation_under_Cause_No._44441.pdf.

239. *Id.* at 2-3.

240. Verified Petition of Indianapolis Power & Light Co., Cause No. 44339 (Ind. Util. Regulatory Comm'n May 14, 2014), https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631801b518e.

241. *Id.* at 6.

242. *Id.* at 33-34.

243. *Id.* at 24.

Electric Company, and DTE Gas Company that implemented a framework for protection of customer data.[244] The MIPSC established in previous orders that utilities could only collect, use, and disclose customer data for primary utility purposes and any non-utility purposes require the customer's consent.[245] Utilities were also required to protect customer data from unauthorized use or disclosure by affiliates, contractors, or agents of the utility while ensuring unobstructed access for customers or any third-party authorized by the customer.[246] The utilities were ordered to file tariffs, substantially similar to those attached to the order, within thirty days of its issuance.[247]

2. MISS DIG Underground Facility Damage Prevention and Safety Act

The MISS DIG Underground Facility Damage Prevention and Safety Act, which Michigan Governor Rick Snyder signed into law on November 26, 2013,[248] repealed and replaced a 1974 law protecting underground public utility facilities from damage during excavation and blasting.[249] Under the new law, excavators are required to provide a minimum of seventy-two hours' notice of their intent to dig, with this notice being submitted via a centralized system that notifies owners and operators of underground facilities to mark their lines in accordance with national standards within twenty-four hours.[250] The law gives the MIPSC enforcement authority with the ability to impose penalties and requires the MI PSC to develop related forms and rules.[251] This law is tie-barred to Senate Bill 539 (passed in 2013)[252] which eliminates governmental immunity for government entities that fail to comply with the requirements of the law.[253]

3. Investigation into Cost Allocation and Rate Design

On June 17, 2014, Governor Snyder signed Public Act 169 of 2014, which initiated an examination of cost allocation and rate design methods for electric utilities.[254] The MIPSC was required to initiate a proceeding within sixty days for utilities with more than one million customers.[255] Utilities must then file within sixty days to modify their cost allocation and rate design methodology to ensure rates are equal to cost of service.[256] The MIPSC was required to issue a final order within 270 days of the utility filings that puts the new methodology in place no

244. To Review Issues Concerning Customer Information and Data Privacy Related to Advanced Metering Infrastructure Deployment, Case No. U-17102, at 4 (Mich. Pub. Serv. Comm'n Oct. 17, 2013).

245. *Id.* at 3.

246. *Id.* at 3-4.

247. *Id.* at 4-5.

248. MICH. COMP. LAWS §§ 460.721-733 (2013).

249. *Id.*

250. *Id.* §§ 460.725(1), 460.727(4).

251. *Id.* §§ 460.731(2), (4), 460.732(3).

252. S.B. 539, 97th Leg., Reg. Sess. (Mich. 2013).

253. *Id.* § 7(2).

254. MICH. COMP. LAWS § 460.11 (2014).

255. *Id.* §§ 460.11(3), (10).

256. *Id.* § 460.11(3).

later than December 1, 2015.[257] The MIPSC was also required to order the presiding administrative law judge to submit an interim report to the Michigan legislature within 150 days from when the utility proposals are filed, explaining how they have complied with the law and including a summary of the record evidence and positions of the parties on a list of items.[258] Finally, the MIPSC was required to submit the proposal for decision for each proceeding to the legislature with a summary of the evidence presented no later than sixty days before issuance of a final order.[259] Smaller utilities have 180 days to file a proposal to modify their cost allocation and rate design methods, while those with less than 120,000 customers may do so within two years.[260]

Also on June 17, 2014, Governor Snyder signed a companion bill to expand the use of the Utility Consumer Representation Fund to include cases related to cost allocation and rate design proceedings.[261] Regulated utility companies[262] contribute funding that supports the participation of non-profit groups, local units of government, and the Michigan Attorney General to participate in state and federal administrative and judicial cases impacting customer rates.[263]

E. Missouri

1. Standard of Review

In *Office of Public Counsel v. Missouri Public Service Commission*, the Supreme Court of Missouri addressed the proper standard for determining whether a utility reasonably incurred its expenditures in a transaction with its affiliate.[264] Although a utility's transactions normally benefit from a "presumption of prudence" when subject to review for reasonableness by the Missouri Public Service Commission (MOPSC), the court held that, as a matter of first impression, it was improper for PSC to rely on [the] presumption that [the] utility's costs in transactions with its affiliate were prudently incurred.[265] The court explained that the MOPSC's "affiliate transaction rules were enacted in an effort to prevent regulated utilities from subsidizing their non-regulated activities. To presume that a regulated utility's costs in a transaction with an affiliate were incurred prudently is inconsistent with these rules," and thus, the presumption of prudence does not apply to affiliate transactions.[266]

In *Union Electric Co. v. Public Service Commission*, the Missouri Court of Appeals held that, as a matter of first impression, certain MISO transmission costs could be passed through a regulated electric utility's Fuel and Purchased Power

257. *Id.* § 460.11(4); This bill is structured to address a special contract for Hemlock Semiconductor that was protected from de-skewing by 2010 PA 297 and which will be repealed effective December 1, 2015.

258. *Id.* § 460.11(6).

259. *Id.* § 460.11(7).

260. *Id.* §§ 460.11(11)-(12).

261. *Id.* § 460.6m(17).

262. *Id.* § 460.6m(2) (except cooperatives under § 460.6m(6)).

263. *Id.* §§ 460.6m(2)(a), (12), (17).

264. Office of Pub. Counsel v. Mo. Pub. Serv. Comm'n, 409 S.W.3d 371, 376 (Mo. 2013).

265. *Id.*

266. *Id.* at 381.

Adjustment Clause (FAC).[267] Specifically, the court found that the MOPSC "was within its authority in permitting Ameren Missouri to use a FAC to pass on the [MISO Schedule 26 and 26A transmission] charges."[268] In reaching its decision, the court concluded that the word "transportation" in the FAC statute encompassed transmission.[269]

2. Union Electric Company d/b/a Ameren Missouri (Ameren Missouri)

On April 8, 2014, the MOPSC issued an order granting a CCN to Ameren Missouri to build a 5.7 MW direct current photovoltaic solar generating facility, subject to certain conditions.[270] This facility would be the largest single site solar facility in Missouri and it is expected to be completed by the end of 2014.[271] In approving the application, the MOPSC explicitly stated that "[n]othing in this order shall be considered a finding by the Commission of the reasonableness or prudence of the expenditures herein involved, or of the value for ratemaking purposes of the properties herein involved, or as acquiescence in the value placed on said property" and that "[t]he Commission reserves the right to consider the ratemaking treatment to be afforded the properties herein involved, and the resulting cost of capital, in any later proceeding."[272]

3. Kansas City Power & Light Company (KCP&L)

On June 5, 2014, the MOPSC issued an order approving KCP&L's proposed demand-side management programs.[273] KCP&L had applied to the MOPSC on January 7, 2014, for approval of demand-side programs and authority to "establish a Demand-Side Investment Mechanism (DSIM) as contemplated by the Missouri Energy Efficiency Investment Act (MEEIA) and the [MOPSC's] implementing regulations."[274] The order approved twelve demand-side MEEIA programs, established annual energy and demand savings targets and a budget of $19,175,842 for the MEEIA programs, and "allowed KCP&L to recover the costs of the MEEIA programs by establishing a DSIM."[275]

F. Ohio

1. Amended Substitute House Bill 483 (Am.Sub.HB 483)

As part of Ohio Governor John Kasich's mid-biennium budget review proposal, the Ohio General Assembly introduced Am.Sub.HB 483 on March 18,

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267. Union Elec. Co. v. PSC, 422 S.W.3d 358, 360 (Mo. Ct. App. 2013).

268. *Id.* at 361.

269. *Id.* at 367.

270. Order Approving Amended Non-Unanimous Stipulation and Agreement, No. EA-2014-0136 (Mo. Pub. Serv. Comm'n Apr. 8, 2014).

271. Press Release, Mo. Pub. Serv. Comm'n, PSC Approves Agreement in Ameren Missouri Solar Case (Apr. 8, 2014), http://psc.mo.gov/Electric/PSC_Approves_Agreement_In_Ameren_Missouri_Solar_Case.

272. Order Approving Amended Non-Unanimous Stipulation and Agreement, No. EA-2014-0136, at 3-4 (Mo. Pub. Serv. Comm'n Apr. 8, 2014).

273. Order Approving Stipulation and Agreement, No. EO-2014-0095, at 2 (Mo. Pub. Serv. Comm'n June 5, 2014).

274. *Id.* at 1.

275. *Id.* at 2.

2014.[276] The bill's wind setback provisions were proposed as being effective September 15, 2014.[277] Am.Sub.HB 483 amends sections 4906.20 and 4906.201 of the Ohio Revised Code, which prescribe regulations regarding economically significant wind farms (aggregate capacity of five to fifty MW) and wind farms that are major utility facilities (aggregate capacity of fifty MW or more) in the state.[278] Under current law, two minimum setbacks for wind turbines of such wind farms exist: (1) a 1125-foot-minimum setback measured "from the tip of the [turbine's] nearest blade at ninety degrees to the exterior of the nearest, habitable, residential structure, if any, located on adjacent property at the time of the [Ohio Power Siting Board (OPSB)] certification application;" and (2) a minimum setback distance, measured from the turbine's base to the wind farm property line, equal to 1.1 times the total height of the turbine from its base to the tip of its highest blade.[279] The bill changes the 1125-foot-minimum setback by requiring it to be measured, not from the turbine blade to the nearest, habitable, residential structure located on adjacent property at the time of the certification application, but from the turbine blade to the property line of the nearest adjacent property line at the time of the certification application.[280]

2. Renewable Energy Legislation

On March 28, 2014, the Ohio General Assembly introduced Substitute Senate Bill 310 (Sub.SB 310), which, among other things, amends Ohio's renewable energy, energy efficiency, and peak demand reduction requirements.[281] Current law requires electric distribution utilities (EDUs) and electric services companies (ESCs) to provide 25% of the electricity supply required for their Ohio retail electric sales from "alternative energy resources" by 2025.[282] While annual benchmarks are provided for meeting the renewable portion of the alternative energy requirement, no annual benchmarks are provided for meeting the advanced portion.[283] Consequently, Sub.SB 310 repeals the advanced energy component, eliminating references to the "alternative energy resource requirements" and refers instead to the "renewable energy resource requirements."[284]

The bill also freezes the renewable and solar energy benchmarks at the 2014 level for 2015 and 2016,[285] but requires that the benchmarks resume in 2017[286] at

276. *Mid-Biennium Review*, OHIO LEGIS. SERVICE COMM'N, http://www.lsc.state.oh.us/fiscal/mbr130/defaultlink.htm (last visited July 3, 2014).

277. Am. Sub. H.B. 483, 130th Gen. Assemb., Reg. Sess. (Ohio 2014).

278. OHIO LEGIS. SERV. COMM'N, BILL ANALYSIS: AM. SUB. H.B. 483 130TH GENERAL ASSEMBLY (AS PASSED BY THE SENATE) 163 (2014).

279. *Id.*

280. *Id.* at 161.

281. Sub. S.B. 310, 130th Gen. Assemb., Reg. Sess. (Ohio 2014). Sub. SB 310's effective date is September 12, 2014.

282. OHIO LEGIS. SERV. COMM'N, BILL ANALYSIS: AM. SUB. S.B. 310, 130TH GENERAL ASSEMBLY (AS PASSED BY THE SENATE) 7 (2014) [hereinafter AM. SUB. S.B. 310]. "Alternative energy resources" include both advanced and renewable energy resources. *Id*.

283. *Id.*

284. *Id.*

285. *Id.* at 8.

286. *Id.*

the 2015 levels provided in current law and be extended for two years, until 2027, to accommodate the two-year freeze.[287]

Additionally, current law requires that at least half of the renewable energy resources that an EDU or an ESC implements to meet the benchmarks must be "met through facilities located in Ohio and that the remainder must be met through resources that . . . [are] deliverable into Ohio."[288] Sub.SB 310 eliminates the in-state requirement, instead allowing renewable energy resource requirements to be met through facilities in Ohio or resources deliverable into Ohio.[289]

While "[c]urrent law [allows] renewable energy credits to be purchased from *any entity*, and provides examples of [such] entities," Sub.SB 310 modifies and adds to these examples.[290] First, the bill modifies the description of an owner or operator of a hydroelectric generating facility by including language that adds a hydroelectric generating facility that produces power "that can be shown to be deliverable into [Ohio]."[291] Sub.SB 310 further modifies the placed-in-service date for certain hydroelectric generating facilities.[292] Finally, the bill also adds, as a potentially qualified renewable energy resource, "a seller of compressed natural gas that has been produced from biologically derived methane gas."[293]

Sub.SB 310 "maintains current energy savings through 2014."[294] However, the bill requires an EDU, for 2015 and 2016, to achieve annual energy efficiency (EE) savings "equal to the result of subtracting the cumulative EE savings achieved since 2009 from the product of multiplying the applicable baseline for EE savings by [4.2%]."[295] This represents a change from the annual incremental EE savings of 1% for 2015 and 2016 required under current law.[296] Further, if the result of the calculation is zero or less for the year for which it is being made, "the bill prohibits the EDU from being required to achieve additional EE savings for that year," but the EDU is permitted to do so.[297]

Additionally, while Sub.SB 310 maintains current peak demand reduction (PDR) requirements through 2014, it requires an EDU, for 2015 and 2016, to "achieve PDR equal to the result of subtracting the cumulative PDR achieved since 2009 from the product of multiplying the baseline prescribed for PDR by 4.75%."[298] If the result of the calculation "is zero or less for the year for which [it] is being made, the bill prohibits the EDU from being required to achieve additional PDR for that year," but the EDU is permitted to do so.[299] Sub.SB 310 also specifies that the EDU must "achieve an additional 0.75% of PDR in 2017-

287. AM. SUB. S.B. 310, *supra* note 282, at 8.
288. *Id.*
289. *Id.*
290. *Id.* at 10.
291. *Id.* at 8, 10.
292. *Id.* at 12.
293. AM. SUB. S.B. 310, *supra* note 282, at 10.
294. *Id.* at 11.
295. *Id.* at 11.
296. *Id.*
297. *Id.* at 12.
298. *Id.*
299. AM. SUB. S.B. 310, *supra* note 282, at 12.

2020."[300] "Under current law, EDUs must implement PDR programs designed to achieve a 1% PDR and an additional 0.75% PDR each year through 2018."[301] Further, "[t]he bill prohibits the baseline prescribed . . . for EE savings and PDR from including the load and usage of . . . (1) [b]eginning [in] 2017, a customer for which a reasonable arrangement has been approved . . . [and] (2) [a] customer that has opted out of the utility's portfolio plan."[302]

Finally, Sub.SB 310 provides guidance regarding existing portfolio plans by giving EDUs two options: (1) continue to implement existing plans through 2016, or (2) seek an amendment of the plan.[303] Sub.SB 310 also includes opt-out provisions, which "permit[] certain customers to temporarily opt out of an EDU's portfolio plan . . . between January 1, 2015 and December 31, 2016 if the plan has been amended" or to opt-out for a longer period beginning January 1, 2017, regardless of whether or not the plan has been amended.[304] Under the Bill, the opt-out provisions apply to higher voltage or higher consumption customers.[305] After opting-out of an EDU's portfolio plan, these customers are exempt from any EE or PDR cost recovery mechanisms.[306] The bill also removes their opportunity and ability to obtain direct benefits from the portfolio plan(s) and limits their eligibility to participate in or directly benefit from programs arising from the plan(s).[307] In addition to being permitted to opt out, under Sub.SB 310, a customer is also permitted to opt back in to the EDU's portfolio plan if the customer has previously opted out for at least three consecutive calendar years.[308] A customer that opts in must remain in for at least three consecutive calendar years before he or she can again elect to opt out.[309]

IV. EAST AND MID-ATLANTIC

A. Maine

1. Northern Utilities, Inc. d/b/a Unitil (Northern)

On December 27, 2013, the Maine Public Utilities Commission (MEPUC) approved the Stipulation submitted by Northern and the Maine Office of the Public Advocate.[310] By the Stipulation, the parties agreed to an increase in Northern's distribution revenues by $3.8 million, to take effect January 1, 2014, as well as a Targeted Infrastructure Replacement Adjustment (TIRA) that will provide for annual adjustments to distribution base rates to recover costs associated with cast

300. *Id.*
301. *Id.*
302. *Id.* at 12-13.
303. *Id.* at 13.
304. *Id.* at 14.
305. Am. Sub. S.B. 301, *supra* note 282, at 14.
306. *Id.*
307. *Id.*
308. *Id.* at 15-16.
309. *Id.* at 16.
310. Northern Utilities, Inc., Proposed Base Rate Increase and Rate Design Modification, Docket No. 2013-00133 (Dec. 27, 2013) (order approving stipulation).

iron replacement expenditures, replacement of bare steel and unprotected steel mains, and services and the replacement of farm tap regulators.[311]

2. Proposed Changes to Capacity Assignment Terms and Conditions

On May 9, 2014, Northern proposed changes to its Retail Choice Program to allow new and existing commercial and industrial customers the option of choosing a third-party natural gas supplier while retaining delivery service from Northern's distribution system.[312] Northern's proposed revisions would eliminate the prohibition against Northern planning, procuring, and assigning capacity resources for all customer classes.[313] As of October 4, 2014, this proceeding is ongoing.

3. Litigation

On March 4, 2014, the Maine Supreme Judicial Court held that the MEPUC's approval of a proposed joint venture allowing Northeast Wind Holdings LLC (Northeast Wind), a subsidiary of Emera Inc. (Emera), the owner of two Maine-based transmission and distribution utilities, to hold a minority share in a joint venture with subsidiaries of First Wind Holdings, LLC (First Wind), to establish a new wind generation company, violated Maine's Electric Industry Restructuring Act (the Act).[314] The Act prohibits single ownership of transmission and distribution utilities and electric generators.[315] The joint venture envisaged Northeast Wind and First Wind's establishment of a new holding entity that would own and operate wind generation projects in Maine, Vermont, and New York.[316] Pursuant to the agreement between the parties, Northeast Wind would hold a 49% interest in the joint venture and "invest $333 million in the form of equity and a loan," eligible for conversion to equity.[317] Though Emera's interest in the joint venture would not be controlling, the court held that because the joint venture would incent Emera—and by extension, its Maine transmission and distribution affiliates—to favor certain generators over others, the proposed restructuring violated the Act.[318]

B. New York

On April 25, 2014, the New York State Public Service Commission (NYPSC) instituted a proceeding[319] "to consider a substantial transformation of electric utility practices to improve system efficiency, empower customer choice, and encourage greater penetration of clean generation and efficiency

311. Northern Utilities, Inc., Proposed Increase in Rates, Docket No. 2013-00133, at 2-3, 6-7 (Dec. 5, 2013) (stipulation).

312. Proposed Changes to Northern's Retail Choice Program, Docket No. 2013-00259, at 1 (May 9, 2014).

313. *Id.* at 4.

314. Electric Industry Restructuring Act, ME. REV. STAT. tit. 35-A, §§ 3201-3217 (1997).

315. Houlton Water Co. v. Pub. Utils. Comm'n, 87 A.3d 749, 751-752 (Me. 2014).

316. *Id.* at 753.

317. *Id.* at 754.

318. *Id.* at 759-760.

319. Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Case No. 14-M-0101 (N.Y. Pub. Serv. Comm'n Apr. 25, 2014) [hereinafter Case No. 14-M-0101].

technologies."[320] The aim of the initiative is to align electric utility practices and the NYPSC's regulatory paradigm with "technological advances in information management and power generation and distribution."[321]

In instituting the proceeding, the NYPSC identified the following policy objectives:

> (1) [e]nhanced [c]ustomer knowledge and tools that will support effective management of their total energy bill; (2) [m]arket animation and leverage of ratepayer contributions; (3) [s]ystem wide efficiency; (4) [f]uel and resource diversity; (5) [s]ystem reliability and resiliency; and (6) [r]eduction of carbon emissions."[322]

The NYPSC stated that the staff of the New York State Department of Public Service (DPS Staff) prepared a Report and Proposal (Report) which addressed the regulatory, customer, and market questions on these policy objectives, and which recommended that the NYPSC "consider fundamental changes in the manner in which utilities provide service," including a reconsideration of the utility business model.[323] Specifically, "[t]he Report describes a new business model for energy service providers in which distributed energy resources" will be a primary tool in planning operating electricity systems such that "customers are empowered to optimize priorities [as to] reliability, cost, and sustainability," and where "the utility functions as a Distributed System Platform Provider (DSPP)" that manages and coordinates distributed resources and provides a market wherein customers may optimize priorities "while providing, and being compensated for, system benefits."[324] The NYPSC recognized that "[c]onsideration of a DSPP model for utilities must be accompanied by consideration of reforms to [existing] ratemaking practices."[325] Thus, the NYPSC initiated the proceeding to examine how existing practices should be modified to establish DSPPs in a manner described in the Report, and how the NYPSC's "regulatory practices should be modified to incent utility practices that best promote [its] policies and objectives, including the promotion of energy efficiency, renewable energy, least cost energy supply, fuel diversity, system adequacy and reliability, demand elasticity, and customer empowerment."[326]

The NYPSC established two parallel tracks in this proceeding—one involving a collaborative process to examine the DSPP issues identified in the Report and on the "[i]mpacts to wholesale markets, opportunities for customer engagement, and other essential related issues," and another focusing on "regulatory changes and ratemaking issues," with a status report on regulatory reform issues due to the NYPSC on September 4, 2014.[327] The NYPSC expects

320. *Id.* at 5.
321. *Id.* at 2.
322. *Id.*
323. *Id.* at 2-4.
324. *Id.*
325. Case No. 14-M-0101, *supra* note 319, at 4.
326. *Id.* at 7.
327. *Id.* at 6.

to reach generic policy determinations by the end of 2014 on the first track and in the first quarter of 2015 on the second track.[328]

C. Pennsylvania

The Pennsylvania Public Utility Commission (PAPUC) has recently confronted issues involving the use of "pass-through event" clauses in "fixed rate" electricity contracts. The PAPUC ordered, on November 14, 2013, that new contracts with pass-through clauses cannot be labeled "fixed price."[329] In the wake of this order, the PAPUC is considering whether an electric generation supplier (EGS) may use a "pass-through event" clause in a fixed-rate electricity contract to recover ancillary transmission costs.[330]

On May 15, 2014, the Office of Small Business Advocate (OSBA), which represents the interests of small businesses before the PAPUC, petitioned the PAPUC for a declaratory order regarding the pass-through charges.[331] In its petition, the OSBA alleged that EGS FirstEnergy Solutions Corporation (FES) sought to use a pass-through event clause in its fixed-rate contracts to recover costs incurred during January 2014 due to unusually cold weather.[332] OSBA argued that PJM Interconnection, LLC (PJM), did not "impose" new charges on FES within the meaning of the pass-through event clause.[333] On June 6, 2014, a group of FES customers filed a petition to intervene, agreeing "with the OSBA that FES's fixed-price contracts do not permit such [ancillary service] charges to be billed to any customers on such fixed-price agreements."[334]

D. South Carolina

On May 22, 2014, Duke Energy Carolinas, LLC (Duke Carolinas) proposed to the South Carolina Utilities Commission (SCUC) an experimental load retention rate schedule for industrial customers.[335] Qualifying customers would receive a rate decrement of $0.0765 per kWh during the period that the schedule is in effect.[336] This shareholder-funded proposal is intended to provide relief to

328. *Id.* at 7.

329. Guidelines for Use of Fixed Price Labels for Products with a Pass-Through Clause, Docket No. M-2013-2362961 (Pa. Pub. Util. Comm'n Nov. 14, 2013).

330. Petition of the Small Business Advocate for Declaratory Order, Docket No. P-2014-2421556, ¶¶ 5, 7, 10, 12, 14 (Pa. Pub. Util. Comm'n May 15, 2014).

331. *See generally id.*

332. *Id.* ¶¶ 5, 7, 10-14.

333. *Id.* ¶ 10.

334. Petition to Intervene of the FES Industrial and Commercial Customer Coalition, Docket No. P-2014-2421556, ¶ 5 (Pa. Pub. Util. Comm'n June 6, 2014).

335. Application of Duke Energy Carolinas, LLC for Authorization under South Carolina Code Sections 58-27-860 and 58-27-870 to Implement an Experimental Load Retention Rate Schedule for its Industrial Customers, Docket 2014-222-E (S.C. Pub. Serv. Comm'n May 22, 2014).

336. *Id.* at Exhibit 1.

industrial customers and save jobs among the established industries.[337] The SCUC approved the pilot program on June 2, 2014.[338]

E. Virginia

On June 23, 2014, the Virginia State Corporation Commission amended its net metering regulations to implement statutory changes. Specifically, to define "eligible agricultural customer-generators," to require utilities to allow agriculture customer-generators to aggregate loads served by multiple meters, and to establish the framework for participation by agricultural customer-generators in net-metering programs offered by Virginia's investor-owned utilities and electric cooperatives.[339]

337. *Id.* at 6.

338. Application of Duke Energy Carolinas, LLC for Approval to Implement an Experimental Load Retention Rate Schedule for its Industrial Customers, Order No. 2014-515, Docket 2014-222-E (S.C. Pub. Serv. Comm'n June 18, 2014).

339. Amending Regulations Governing Net Energy Metering, Docket No. PUE-2014-00003 (Va. State Corp. Comm'n June 23, 2014).

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