BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. §4928.143 in the Form of an Electric Security Plan.	))))))	Case No. 14-1297-EL-SSO

INITIAL BRIEF
OF
NORTHEAST OHIO PUBLIC ENERGY COUNCIL

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TABLE OF CONTENTS

Page

APPENDICES

Appendix A

SB 221 as Introduced, Section 4928.14(B)(1)

Legislative Service Commission Bill Analysis, 127th General Assembly, SB 221: As Introduced. SB 221 as Passed in the Senate, Section 4928.14(D)(1).

Appendix B

SB 221 as Passed in the Senate, Section 4928.14(D)(1)

Legislative Service Commission Bill Analysis, 127th General Assembly, SB 221: As Passed by the Senate.

Appendix C

SB 221 as Reported in the H. Public Utilities, Section 4928.143(B)(1)

Legislative Service Commission Bill Analysis, 127th General Assembly, SB 221: As Reported by the H. Public Utilities.

Appendix D

SB 221 as Passed by the General Assembly, Section 4928.143(C)(1)

Legislative Service Commission Bill Analysis, 127th General Assembly, SB 221: As Passed by the General Assembly.

EXECUTIVE SUMMARY

The FirstEnergy Utilities' Electric Security Plan IV Application and the Partial Third Stipulation and Recommendation filed in this case (the "Proposal") are wrong for the nearly 500,000 northern Ohio customers that are served by NOPEC's governmental electric aggregation program. The Proposal is wrong because several of its provisions, particularly the Power Purchase Agreement ("PPA") between the FirstEnergy Utilities and its unregulated generation affiliate, FirstEnergy Solutions, are unlawful under Ohio law, unlawful under federal law, and represent bad public policy in Ohio by retreating from the deregulated electric generation market model created by the Legislature that is working well in Ohio.

NOPEC's Initial Brief in this case will show that the Proposal violates Ohio law because, among other things:

- Rider RRS is not permitted under R.C. 4928.143(B).
- Rider RRS imposes a non-bypassable generation charge on NOPEC's large-scale governmental aggregation contrary to R.C. 4928.20(K).
- Rider RRS does not meet the requirements of the PUCO's February 25, 2015 order in the AEP Ohio ESP 3 case, as applied to the FirstEnergy Utilities by Entry of March 23, 2015.
- Rider RRS is an unlawful anti-competitive subsidy under R.C. 4928.02(H).
- First Energy Utilities' ESP IV violates R.C. 4928.143(C) as it is not more favorable in the aggregate than a MRO.
- Rider GDR does not meet the requirements of R.C. 4928.143(B)(2) to be an item included in an ESP.
- The Third Partial Stipulation and Recommendation filed does not satisfy the three-prong test in *Consumers' Counsel v. Pub. Util. Comm.*, 64 Ohio State 3d 123 (1992).

The Proposal violates federal law because, among other things:

- FERC has exclusive jurisdiction over wholesale electric prices, not the PUCO.

- Rider RRS violates the Supremacy Clause and the dormant Commerce Clause of the United States Constitution.

- If Rider RRS violates the United States Constitution, any Commission order approving it is void ab initio.

- Rider RRS interferes with the operation of federal wholesale electric markets.

Finally, the Proposal represents bad public policy for the State of Ohio because, among other things:

- Consumers in northern Ohio will be burdened with extra electric costs estimated to be about $3.6 Billion over the eight (8) year ESP IV plan period.

- NOPEC's customers will be required to pay FirstEnergy Solution twice for generation supply by virtue of Rider RRS.

- Rider RRS represents a retreat from SB3's deregulation of electricity generation and competitive electric markets in Ohio.

- Rider RRS undermines the objectives of the PJM energy and capacity markets.

- The Companies should be required to undertake filing of distribution rate cases at the PUCO instead of receiving automatic distribution revenue rate increases.

Each of the above reasons, individually, should result in the Commission's rejection of the Proposal. When considered in their entirety, NOPEC submits that the Commission must reject the Proposal.

I. INTRODUCTION

A. NOPEC's Nearly 500,000 Customers Will be Required to Pay FirstEnergy Solutions Twice for Generation Supply if the Commission Approves the Proposed Rider RRS.

The Northeast Ohio Public Energy Council ("NOPEC") is a regional council of governments established under R.C. Chapter 167, and is the largest governmental retail energy aggregator in the State of Ohio. It is comprised of 164 member communities in the thirteen (13) northern Ohio counties of Ashtabula, Lake, Geauga, Cuyahoga, Summit, Lorain, Medina, Trumbull, Portage, Huron, Columbiana, Mahoning, and Seneca. NOPEC provides electric aggregation service to approximately 500,000 retail electric customers – or nearly one-third of the retail electric customers located in the service territories of two FirstEnergy Corp. operating companies: The Cleveland Electric Illuminating Company ("CEI") and Ohio Edison Company ("OE").[1]

Since the enactment of SB 3 in 1999, NOPEC has been an active participant in Ohio's deregulated electric generation market,[2] arranging electric supply contracts for its customers that will result in savings of more than $300 million through 2019, when its current contract expires. Significantly, NOPEC's current contract is with FirstEnergy Solutions ("FES"), an affiliate of CEI and OE. Under this contract, FES provides NOPEC customers with full-requirements retail electric service for a nine-year period, from January 1, 2011 through December 31, 2019. The publicly available terms of this competitively bargained-for contract show that NOPEC's

[1] IGS Exhibit 13 (White Supplemental) at 6.

[2] See R.C. 4905.03.

residential customers pay a fixed 6% off their EDU's price to compare, and its small commercial customers pay a fixed 4% off the price to compare during the contracts' nine-year term.[3]

The most controversial provision of the Companies'[4] electric security plan ("ESP IV") is the proposed nonbypassable rider under which all distribution customers must pay a return of, and on, FES's investment in the Sammis and Davis Besse generating facilities, as well as FES's share of power from the Ohio Valley Electric Corporation ("OVEC Entitlement") (collectively "PPA Units"). Specifically, the Companies propose to enter into a purchase power agreement with FES under which they would purchase the power of the PPA Units and sell these resources' capacity, energy and ancillary services into PJM Interconnection, LLC ("PJM"). The full costs of these resources plus a return on invested capital, net of associated market revenues, would be recovered from all distribution customers through the nonbypassable Retail Rate Stability Rider ("Rider RRS).[5]

The record in this proceeding indisputably shows that during the remainder of the NOPEC/FES supply contract (through 2019), NOPEC's customers will be required to pay an additional, nonbypassable charge for FES' generation through Rider RRS, if it is approved.[6] According to OCC/NOPEC witness Wilson, from 2016 through 2019, Rider RRS will cost NOPEC's typical residential customer $427.04 in CEI's service territory, and $413.94 in OE's service territory,[7] or a total of over $200 million for all NOPEC customers through 2019. In other words, NOPEC customers would be harmed by being required to give up their bargained-for

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[3] Tr. XXII at 4591 (Wilson Re-Cross). The Companies did not contest these terms at hearing, but only argued that they were confidential. Tr. XXII at 4592-4594. These terms are publicly available as reported by FirstEnergy Corp.'s own news release. http://www.prnewswire.com/news-releases/firstenergy-solutions-and-nopec-enter-into-nine-year-agreement-78317142.html.

[4] The "Companies" refer to FirstEnergy Corp.'s operating companies: CEI, OE and The Toledo Edison Company ("TE").

[5] OCC/NOPEC Ex. 4 (Wilson Direct) at 5

[6] OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 8; Companies Ex. 33 (Ruberto Direct) at Ex. JAR-1.

[7] OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 13.

FES discount and pay FES twice for generation. As explained below, Rider RRS is unlawful because, among other reasons, it violates R.C. 4928.20(K), which protects large-scale governmental aggregations from the harmful effect of nonbypassable charges. Rider RRS charges in the proposed electric service plan ("ESP IV") could amount up to *$3.6 billion* over an eight-year term for all customers in the Companies' three service territories,[8] and *over $400 million* for all for NOPEC customers in the CEI and OE service territories for the eight-year term.[9]

NOPEC's immediate concerns are that its customers not pay twice for FES' generation and also with the sheer enormity of costs to be recovered under Rider RRS. NOPEC's broader concern is with the dangerous interference Rider RRS would have on Ohio's ability to ensure effective competition in the provision of retail electric service, as required by statute.[10] In this vein, Rider RRS violates not only state law, but also federal law and even the Constitution of the United States.

II. OHIO'S REGULATORY PARADIGM FOR ELECTRIC SERVICE UNDER SB 3 LIMITS THE COMMISSION'S AUTHORITY TO RETAIL ELECTRIC SERVICE, RECOGNIZING FERC'S EXCLUSIVE JURISDICTION OVER WHOLESALE ELECTRIC PRICES.

The Commission, as a creature of statute, may exercise only that jurisdiction conferred upon it by the General Assembly.[11] In R.C. 4905.03(C), the legislature has limited the Commission's jurisdiction over electric light companies only to when they are:

> *** engaged in the business of supplying electricity for light, heat, or power purposes ***<u>to consumers within this</u>***

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[8] OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 12-13.

[9] Id. A typical NOPEC residential customer will pay Rider RRS surcharges of $823.17 in CEI's service territory and $797.91 in OE's service territory during the eight-year term of proposed ESP IV. The 500,000 NOPEC customers, combined, will pay over $400 million during the same eight year term.

[10] See R.C. 4928.02(H) (ensuring effective competition in the provision of retail electric service is a policy of this state).

[11] See, e.g., *Cols. Southern Power Co. v. Pub. Util. Comm.*, 67 Ohio St.3d 535, 537, 620 N.E.2d 835 (1993).

> ***state***, including supplying electric transmission service for electricity delivered to consumers in this state, ***but excluding a regional transmission organization approved by the federal energy regulatory commission***. [Emphasis supplied.]

By limiting the Commission's jurisdiction to "consumers within this state," and expressly excluding jurisdiction over the activities of regional transmission organizations ("RTO"), the legislature clearly intended the Commission's authority be limited to retail service. Indeed, consistent with R.C. 4905.03(C), R.C. 4928.141(A) requires electric distribution utilities to "provide consumers" with "a standard service offer of all competitive retail electric services."

The Ohio legislature's regulatory paradigm recognizes that the Federal Power Act ("FPA") vests exclusive jurisdiction over wholesale electric prices in the Federal Energy Regulatory Commission ("FERC").[12] FERC, in turn, created the RTOs (such as PJM Interconnection, Inc. ("PJM")) to oversee wholesale electric service in multistate markets.[13] Rider RRS encroaches on FERC's exclusive jurisdiction and, in doing so, harms the Companies' customers through its effects on PJM's energy and capacity markets.

A. Rider RRS undermines the PJM energy market by permitting the Companies to develop offer strategies that will harm their captive customers.

An underlying premise of restructured energy markets, such as that operated by PJM, is that customers will benefit from generation assets that supply electricity the most efficiently over the short-run. This benefit is accomplished through a bidding process under which generators must compete against one another to provide electricity to customers. Those generating assets that are able to provide electricity reliably and at least cost are the assets that ultimately are

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[12] See 16 U.S.C. 824(b)(1); *Nantahala Power & Light Co. v. Thornburgh*, 476 U.S. 952, 966; *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241, 251 (3d Cir. 2014).

[13] *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467, 472 (4th Cir. 2014).

dispatched.[14] However, under proposed Rider RRS, the PPA Units would not be subject to this competitive selection process to recover the PPA Units costs. This is because the capital and operating costs, plus a guaranteed return on investment, for the PPA Units would be subsidized by captive customers.[15] This unlawful subsidization would permit the Companies to follow any strategy in offering the PPA Units into PJM to the detriment of NOPEC's customers and all customers, as illustrated by the following two examples.

First, the Companies could offer the PPA Units into PJM below the Units' costs. Although the Companies would not recover the Units' full costs through the market, the Companies and FES would receive the cost deficit from customers through the Rider RRS subsidy. Under this offer strategy, the artificially low-priced energy from the PPA Units would be dispatched instead of the energy offers of lower-cost generators. Thus, not only would the Companies' captive customers be forced to pay the Rider RRS subsidy, they also would be forced to pay higher PJM market prices for energy due the exclusion of the lower-cost generators' supply from the market.[16]

Second, and conversely, the Companies could choose a strategy to offer the PPA Units above their costs. Under this strategy (also referred to as "economic withholding"), the PPA Units would not be dispatched and would receive no revenues from the market. Nevertheless, the Companies' captive customers would be required to support the Units through the Rider RRS subsidy. Moreover, by withholding the PPA Units, PJM would be forced to operate higher-cost generators, increasing the Companies' customers' electricity cost even further.[17]

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[14] OCC/NOPEC Ex. 1 (Sioshansi Direct) at 9.
[15] OCC/NOPEC Ex. 1 (Sioshansi Direct) at 12.
[16] OCC/NOPEC Ex. 1 (Sioshansi Direct) at 12-13.
[17] OCC/NOPEC Ex. 1 (Sioshansi Direct) at 13.

The record in this proceeding does not disclose the offer strategies that the Companies will use for the PPA Units, and the Companies provide no guarantee, or means to verify, that their offer strategies will not have anti-competitive effects on the PJM wholesale electric markets to the detriment of Ohio consumers. This fact alone, and particularly when coupled with others discussed below, support the Commission's rejection of the Companies' Application.

B. Rider RRS undermines the PJM capacity market by providing FES a disincentive to retire plants, an incentive to over invest in the PPA Units, and an incentive to develop offer strategies that will harm its captive customers.

PJM supplements the revenues generators receive from the energy markets through the capacity market, based on the Reliability Pricing Model ("RPM"). The capacity market is meant to ensure the long-run efficiency of the electric power system. It does so by requiring generators to compete against each other in the RPM capacity auctions on the basis of cost. Generators that can provide capacity and reliability to the system at lower cost will clear the auction and receive capacity payments. This process is intended to encourage the retention and entrance of efficient, reliable, and low-cost generation in PJM. This can be accomplished through investment in new low-cost generation technologies (which represent increased profit opportunities), or by the pressure the process exerts on generation owners to reduce capital cost and operating costs for existing plants, and thus increase profitability.[18] Rider RRS threatens to undermine PJM's capacity market in the following two ways.

First, Rider RRS operates to transfer all costs and operating risks from FES to the Companies' captive customers, assuring FES full cost recovery plus a guaranteed return on investment. Thus, the subsidy provided by Rider RRS' provides a disincentive for FES to retire the PPA Units, even if less efficient than those with which it competes in the RPM auctions.

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[18] OCC/NOPEC Ex. 1 (Sioshansi Direct) at 10-12.

This failure to retire the PPA units in favor of lower-cost and more efficient generation, would increase the cost of electricity for consumers in the long run.[19] Indeed, if FES' return on investment is high enough, the PPA and Rider RRS subsidy may create a strong financial incentive for FES and the Companies to overinvest in the PPA Units, which would increase the Rider RRS subsidy even more.[20]

Second, as explained above, the subsidy provided by Rider RRS could affect the Companies' offer strategy, resulting in the PPA Units being offered into PJM either under or above their costs. If offered above their costs, the PPA Units would increase capacity costs; and if offered below costs, the PPA Units could suppress capacity costs. If the Companies' offer strategy suppresses capacity costs, this could prevent in lower-cost generation from entering the market. This would cause customer prices to increase further in the long run, because long-term investments are not being driven by market fundamentals.[21]

C. The participation of the Companies' affiliated generating assets in PJM provides an additional incentive for them to develop offer strategies that will harm their captive customers.

The Companies have a number of affiliates that own generation assets. These affiliated generating assets participate in the PJM-operated markets and are not included in the proposed PPA. The participation of these affiliated assets in the markets further complicates how the Companies and FES may offer the PPA Units into the PJM-operated markets. As explained

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[19] OCC/NOPEC Ex. 1 (Sioshansi Direct) at 14

[20] See, also, PJM Power Providers' Group/Electric Power Supply Association ("P3/EPS") Ex. 1 (Kalt Direct) at 9 (As a result of being effectively guaranteed a return of, and on, its investments, FES "would rationally seek to make capital investments in the plants, even when such investments are uneconomic relative to alternatives in the open marketplace.")

[21] OCC/NOPEC Ex. 1 (Sioshansi Direct) at 14-15; see, also, P3/EPS Ex. 1 (Kalt Direct) at 8 (Rider RRS "will depress prices in the wholesale market, benefit inefficient producers at the expense of more efficient ones, and crowd out the new and existing suppliers.'); IMM Ex. 1 (Bowering Direct) at 3 (The Rider RSS subsidy "negatively affect the incentives to build new generation and would likely result in a situation where only subsidized units would ever be built.")

above, the strategies used for offering the PPA Units into the PJM-operated markets can suppress or increase wholesale prices.

In a worst-case scenario for customers, the Companies would have an incentive to economically withhold the PPA Units from PJM. Although the PPA Units would not generate any revenues in the market, FES would nevertheless earn a guaranteed profit through the PPA. The Companies' profits would not be affected because 100 percent of the PPA costs would be passed through Rider RRS to the Companies' customers. Moreover, the resulting increase in wholesale PJM-market prices would improve the revenues earned by affiliate-owned generators participating in the PJM-operated markets (including FES). In this worst-case scenario, customer costs rise due to higher wholesale market prices and customers also must pay to subsidize generation assets that are not used to their full potential to serve customer demands (due to their being economically withheld from the market).[22]

D. The subsidy provided by Rider RRS undermines the PJM capacity market by providing the Companies a disincentive to control the PPA Units' costs.

As explained above, the PJM-operated markets provide generation owners with strong incentives to reduce costs. This is because generation owners must recover costs through revenues earned in the market and increase shareholder value. Any cost reduction achieved by a generation owner translates into a profit increase. These incentives are completely eliminated by the proposed Rider RRS subsidy.[23]

For example, a flue-gas desulfurization ("FGD") system may be added to a coal-fired plant in an effort to reduce pollutants. However, this would only be done if the FGD system is the most efficient means of achieving these emissions reductions. If so, the costs of the FGD

[22] OCC/NOPEC Ex. 1 (Sioshansi Direct) at 16-17.

[23] OCC/NOPEC Ex. 1 (Sioshansi Direct) at 18.

system would be borne by the market and the coal-fired plant would recover its costs. Otherwise, if a more efficient source of emissions reduction exists (*e.g.*, displacing the coal-fired plant with a natural gas-fired plant), that asset would enter the market and drive the coal-fired plant out.[24]

The Companies' proposed Rider RRS eliminates any incentives for FES to make only economically prudent investments, because recovery of its costs and a return on investment are ensured by Rider RRS. Considering that the PPA guarantees full recovery of all PPA Unit costs and a return on investment, the PPA provides FES no incentive to ever retire any of the PPA Units. Moreover, all costs and expenditures prior to December 31, 2014 are deemed to be prudent. Thus, the Commission has no opportunity to disallow costs arising from poor decisions made by FES, which could affect the future of the PPA Units.[25]

E. Rider RRS violates the Supremacy Clause and the dormant Commerce Clause of the U.S. Constitution.

The Companies' proposed Rider RRS violates the U.S. Constitution's Supremacy Clause and dormant Commerce Clause. As stated above, FES' compensation for wholesale electric services will be increased (or decreased) through nonbypassable Rider RRS, which (if approved) would collect the difference between the revenue FES receives from the PPA Units through PJM and the Units' cost of generation. Because wholesale electricity compensation is within the exclusive jurisdiction of FERC, the Commission is preempted from approving Rider RRS. Further, Rider RRS has both a discriminatory purpose and a discriminatory effect and a Commission order approving it would violate the dormant Commerce Clause.

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[24] OCC/NOPEC Ex. 1 (Sioshansi Direct) at 18-19.

[25] OCC/NOPEC Ex. 1 (Sioshansi Direct) at 19.

Indeed, only a few weeks ago, the U.S. Supreme Court affirmed that wholesale electric service compensation is within FERC's exclusive jurisdiction in its opinion in *Federal Energy Regulatory Commission v. Electric Supply Association*.[26] In affirming that the FPA gives FERC the authority to regulate wholesale market operators' compensation of demand response bids, the Court further clarified the boundary between state authority over retail matters and federal authority over wholesale matters. Specifically, the Court approved a construction of the FPA's language whereby FERC's exclusive jurisdiction is limited to rules or practices "directly affecting the [wholesale] rate."[27] The Court then determined that regulation of demand response fell within this authority.[28] By the same token, the Court rejected the notion that states have authority to regulate demand response because the FPA "leaves no room either for direct state regulation of the prices of interstate wholesales" or for regulation that "would indirectly achieve the same result."[29] The Commission must be mindful that its jurisdiction does not directly or indirectly allow it to regulate the price of interstate wholesales.

1. Approval of the ESP violates the Supremacy Clause of the U.S. Constitution because it intrudes upon the exclusive jurisdiction of FERC and is preempted by the Federal Power Act.

The Supremacy Clause of the United States Constitution renders federal law "the supreme Law of the Land," and "is grounded in the allocation of power between federal and state governments . . . ."[30] The doctrine of preemption emerges from the Supremacy Clause, which

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[26] No. 14-840, slip. op., Kagan, J., (January 25, 2016).

[27] Id. at 15.

[28] Id. at 16.

[29] Id. at. 26.

[30] U.S. Const. art. VI, cl. 2; *Maryland Pest Control Assoc. v. Montgomery County*, 884 F.2d 160, 162 (4th Cir. 1989) (per curiam).

"invalidates state laws that 'interfere with, or are contrary to,' federal law."[31] Congress may preempt or supersede state or local law, either expressly through explicit statutory language or impliedly through field or conflict preemption, even in areas traditionally reserved to state regulatory authority.[32]

Proposed Rider RRS is field preempted by the FPA. FPA sections 205 and 206 empower FERC exclusively to regulate rates for the interstate and wholesale sale and transmission of electricity.[33] FERC's exclusive power to regulate wholesale sales of energy in interstate commerce is well-established: "The [FPA] long has been recognized as a comprehensive scheme of federal regulation of all wholesales of [energy] in interstate commerce."[34] When a specific transaction is subject to exclusive federal FERC jurisdiction and regulation, state regulation is preempted as a matter of federal law and the U.S. Constitution's Supremacy Clause.[35]

Two recent federal court decisions demonstrate that an order by the Commission approving Rider RRS would be preempted by the FPA. In the first decision, *PPL EnergyPlus LLC v. Nazarian*,[36] the Fourth Circuit reviewed an order of the Maryland Public Service Commission ("Maryland Commission") that increased compensation for the provision of wholesale electric services of an entity that was seeking to construct a generation plant. Specifically, the Maryland Commission order directed the incumbent local utilities to enter into guaranteed contracts for differences ("CfD's") with the winning bidder constructing a new power

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[31] *See Gade v. Nat'l Solid Wastes Mgmt. Ass'n*, 505 U.S. 88 (1992); *Hillsborough Cnty., Fla. v. Automated Med. Labs., Inc.*, 471 U.S. 707, 712-13 (1985) (internal citation omitted) [(quoting *Gibbons v. Ogden*, 22 U.S. 1, 211 (1824)].

[32] *See Hillsborough Cnty.*, 471 U.S. at 713; *Shaw v. Delta Air Lines, Inc.*, 463 U.S. 85, 95 (1983) ("'Pre-emption may be either express or implied, and 'is compelled whether Congress' command is explicitly stated in the statute's language or implicitly contained in its structure and purpose.'") (citation omitted).

[33] 16 U.S.C. § 824(a); *see also id*. at § 824(b).

[34] *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 300 (1988).

[35] *New England Power Co. v. New Hampshire*, 455 U.S. 331, 338 (1982).

[36] *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467 (4th Cir. 2014), cert. granted, 84 U.S.L.W. 3211 (U.S. Oct. 19, 2015) (No.14-614)

plant. The CfD's ensured that any difference between the wholesale clearing price the generator received for energy sold into PJM and the "revenue requirements per unit of energy and capacity sold" would be passed on to Maryland ratepayers by the local electric utilities.[37] The Fourth Circuit held that "the Generation Order [in question] is field preempted because it functionally sets the rate that [the power generator] receives for its sales in the PJM auction."[38]

A similar case in New Jersey also demonstrates that the ESP is preempted by the FPA. At issue in *PPL Energy Plus, LLC, et al., v. Solomon, et al.,*[39] was a New Jersey statute that attempted to encourage the construction of new generation plants by guaranteeing a price of capacity to the builder. The law authorized the New Jersey Board of Public Utilities ("Board") to issue a standard offer capacity agreement and directed the state's four electric distribution utilities to enter into long-term fifteen-year contracts with generators to pay any difference between the PJM capacity payments and the development costs of the generators that the Board approved. The Third Circuit affirmed the federal district court's holding that the New Jersey statute was preempted because the FPA occupied the field of wholesale electricity sales, including the price at which electricity is sold at wholesale.[40]

An order approving the ESP would likewise be preempted by the FPA. The Companies ESP IV "contemplates the Companies acquiring the generation output of specified generation plants [Davis-Besse, Sammis, and the OVEC entitlement] through a purchased power transaction, [and such generation] would then be sold into the PJM Interconnection LLC ("PJM") markets. The costs and revenues will then be netted, and the outcome of the acquisition and sale of the generation—credit or cost—would be included in the proposed Retail Rate

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[37] *Nazarian* at 473-474.

[38] Id. at 476.

[39] 766 F.3d 241 (3[d] Cir. 2014).

[40] Id. at 255.

Stability Rider…that would be applicable to all customers."[41] When "market revenues…exceed the costs," ratepayers "would receive a…credit" and when costs exceed revenues, ratepayers would be charged the difference.[42]

Rider RRS is field preempted because it "functionally sets the rate that [the power generator] receives for its sales in the PJM auction."[43] While the PPA Units' power will be sold into the competitive wholesale market, Rider RRS ensures that ratepayers will pay any difference between competitive generation revenues and the plants' revenue requirement. The effect of the subsidy is to push the [wholesale] price down because the inefficient producer will lower its offer in the PJM RPM capacity market, and this lower offer results in a lower market clearing price.[44] Like the subsidy programs in Maryland and New Jersey, the ESP improperly intrudes on the FERC's jurisdiction by "effectively supplan[ting] the rate generated by the [PJM] auction with an alternative rate preferred by the state" so that power generation facilities that otherwise could not survive on the receipt of FERC's wholesale rates are able to do so as subsidized.[45] Rider RRS, therefore, is preempted by the FPA.

2. Approval of Rider RRS violates the dormant Commerce Clause of the U.S. Constitution because it has a discriminatory purpose and effect against out-of-state power generators.

The U.S. Constitution grants to Congress the power "[t]o regulate Commerce with foreign Nations, and among the several States, and with the Indian Tribes."[46] "Although the Commerce Clause is phrased merely as a grant of authority to Congress . . . it is well established that the Clause also embodies a negative command forbidding the States to discriminate against

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[41] Application, Companies Ex. 1, at 9.

[42] Id.

[43] *Nazarian* at 476.

[44] 3P/EPS Ex. 1 (Kalt Direct) at 24, 30, 32.

[45] *Nazarian* at 476.

[46] U.S. Const. art. I, § 8, cl. 3.

interstate trade."[47] The so-called "dormant Commerce Clause" prohibits economic protectionism ("that is, regulatory measures designed to benefit in-state economic interests by burdening out-of-state competitors") on the part of the States.[48]

The dormant Commerce Clause may be violated if state action constitutes "economic protectionism," which may be found on the basis of either discriminatory purpose[49] or discriminatory effect.[50] "If either type of discrimination is shown, then the state is not entitled 'to a more flexible approach permitting inquiry into the balance between local benefits and the burden on interstate commerce.'"[51] A discriminatory law is "virtually *per se* invalid."[52] It will survive only if it "advances a legitimate local purpose that cannot be adequately served by reasonable nondiscriminatory alternatives."[53]

Rider RRS has both a discriminatory purpose and a discriminatory effect and any Commission order approving it would violate the dormant Commerce Clause. The Companies admit its proposal's discriminatory purpose in the Application when setting forth a series of putative economic advantages that would allegedly flow to Ohio specifically from the continued operation of the Davis-Besse and Sammis generation facilities in particular.[54] These putative benefits include: retaining over 1,000 Ohio jobs, local property tax revenue from the plants, and, perhaps most significantly, "*reducing Ohio's need to rely disproportionately on plants outside of*

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[47] *Associated Indus. of Mo. v. Lohman*, 511 U.S. 641, 646 (1994).

[48] *See New Energy Co. of Ind. v. Limbach*, 486 U.S. 269, 271, 273 (1988) (invalidating under the dormant Commerce Clause a statute that provided a tax credit for sales of ethanol produced in Ohio but not for sales of ethanol produced in certain other states).

[49] *Hunt* v. *Washington Apple Advertising Comm'n*, 432 U.S. 333, 352-353 (1977).

[50] *Philadelphia* v. *New Jersey*, 437 U.S. 617, 624 (1978).

[51] *Bacchus Imps.*, 468 U.S. 263, 270 (1984) (citing *Pike*, 397 U.S. 137, 142 (1970)).

[52] *Or. Waste Systems, Inc.* v. *Dep't of Envtl. Quality,* 511 U.S. 93, 99 (1994)*; Philadelphia* v. *New Jersey,* 437 U.S. 617, 624 (1978).

[53] *Dep't* of Revenue of Ky v. *Davis*, 553 U.S. 328, 338 (citing *Oregon Waste Systems* at 101 (internal quotation marks omitted)).

[54] Application, Companies Ex. 1 at 9.

Ohio. . . ."[55] The adoption of Rider RRS would have an explicitly protectionist purpose: to increase the Ohio-based generation of power purchased by Ohio's electric power customers, at the expense of out-of-state generators.

Further, the effect of Rider RRS is "clearly discriminatory," because it favors some in-state generators over others with which they directly compete.[56] The discriminatory nature of this effect is not mitigated by the fact that it only favors only the limited PPA Units plants in Ohio.[57] Rider RRS can only have the effect of encouraging output from the PPA Units and thereby displacing other, efficient suppliers' output in the wholesale power and capacity markets.[58] The result may even be to force premature retirement of other generators "whose costs are close to capacity market-clearing prices. . . ."[59]

There is no reason to believe that the displaced generators will be exclusively Ohio businesses. Indeed, the discriminatory effect of the ESP is apparent by the Companies' argument that, absent the subsidization of the generation facilities identified in the ESP, the identified plants would likely retire and thereby be displaced by other sources of power, some which would come from outside of Ohio's borders.[60]

3. Because FERC has exclusive jurisdiction over wholesale electricity compensation, a Commission order approving Rider RSS will be void ab initio.

As stated above, wholesale electricity compensation is within the exclusive jurisdiction of FERC. Accordingly, the Commission lacks subject matter jurisdiction over Rider RRS. Lacking subject

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[55] Id. (emphasis added).

[56] *Bacchus Imps.* at 271.

[57] *Id*. at 271 ("[T]he effect [of the subsidy]…is clearly discriminatory, * * *, even though it does not apply to all [in-state operators]. Consequently, as long as there is some competition between the [subsidized local] and [unsubsidized out-of- state business], there is a discriminatory effect.")

[58] 3P/EPS Ex. 1 (Kalt Direct) at 30.

[59] Id. at 33.

[60] Application, Companies Ex. 1 at 9.

matter jurisdiction over Rider RRS, a Commission order approving it will be void ab initio. *Twin City Fire Ins. Co. v. Adkins*, 400 F.3d 293, 299 (6th Cir. 2005), citing *Int'l Longshoremen's Ass'n v. Davis*, 476 U.S. 380, 392, 90 L. Ed. 2d 389, 106 S. Ct. 1904 (1986) (holding that where "a state court . . . has no subject matter **jurisdiction** to adjudicate the issue . . ., any judgment issued by the state court will be ***void ab initio***") (emphasis in original).

III. UNDER OHIO LAW, RIDER RRS IS UNLAWFUL, UNREASONABLE AND NOT IN THE PUBLIC INTEREST.

A. Rider RRS Is Unlawful Because it Does Not Fall Under Any of the Provisions of R.C. 4928.143(B). *In Re Application of Columbus Southern Power Co., et al.*, 128 Ohio St. 3d 512, 2011-Ohio-1788 [¶¶ 31-35], 945 N.E.2d 655.

As stated above, the most controversial provision of ESP IV is the Companies' request for approval of the nonbypassable Rider RRS under which all distribution customers must pay a return of and on FES' investment in the PPA Units. A threshold question presented is whether the Companies' proposed Rider RRS is lawful under Ohio law. Significantly, the Ohio Supreme Court recently held that only the nine items enumerated in R.C. 4928.143(B)(2) may be included in an ESP. *In Re Application of Columbus Southern Power Co., et al.*, 128 Ohio St. 3d 512, 2011-Ohio-1788 [¶¶ 31-35], 945 N.E.2d 655 (hereinafter, "*CSP II*"). Lacking confidence that its proposed Rider RRS fits any of the criteria of R.C. 4928.143(B)(2), the Companies provide various alternative approaches for the Commission's consideration.[61] Their first three alternatives are based on the language of R.C. 4928.143(B)(2)(d), which provides that an ESP may include:

> Terms, conditions, or charges relating to limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals, as would have the

[61] Companies Ex. 155 (Mikkelsen Fifth Supplemental) at 9.

effect of stabilizing or providing certainty regarding retail electric service…

Specifically, the Companies claim that Rider RRS is:

1) A charge that relates to ***bypassability*** as would have the effect of stabilizing or providing certainty regarding retail electric service.
2) A charge that relates to ***default service*** as would have the effect of stabilizing or providing certainty regarding retail electric service.
3) A charge that relates to a ***financial limitation on the consequences of customer shopping but does not limit a customer's ability to shop*** as would have the effect of stabilizing or providing certainty regarding retail electric service.

The Companies' fourth claim is made under R.C. 4928.143(B)(2)(i), that Rider RRS is an economic development and job retention program.[62] Each of the alternatives lacks merit.

1. Rider RRS Is Unlawful Because it Does Not Fall Under Any of the Alternatives Proposed under R.C. 4928.143(B)(2)(d)

a. The Commission already has rejected the Companies' "bypassability" rationale.

In its recent ESP proceeding,[63] AEP Ohio also alleged that it was permissible to include a rider comparable to Rider RRS in its proposed ESP on the basis that it was a charge related to "bypassability." The Commission rightly rejected that argument, finding that, "since nearly any charge may be bypassable or nonbypassable, "bypassability" alone is insufficient to fully meet

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[62] Make no mistake, ESP IV and the proposed Rider RRS are intended for one purpose only – to provide FES with a return of, and on, its investment in the PPA Units. NOPEC discusses the fallacies of the Companies' economic development and job retention claims when discussing below the four additional factors the Commission required for consideration in *In Re Ohio Power*, Case No. 13-2385, Order (February 25, 2015) at 25 ("*Ohio Power*"). Suffice it to say at this point that there is no evidence of record that the PPA Units will be retired if Rider RRS is not approved. *See* Tr. Vol. IV, p. 75 (Companies witness Strah testifying that the Companies have not concluded that the PPA Units will actually be retired if Rider RRS is not approved); *see also* Tr. Vol. XI, p. 2337 (Companies witness Moul testifying that no generation deactivation requests to PJM have been submitted for either Davis Besse or Sammis).

[63] *See*, *Ohio Power*, Order (February 25, 2015)..

the…criteria of R.C. 4928.143(B)(2)(d)."[64] Thus, the Companies' "bypassability" argument must fail.

b. Rider RRS Does Not Relate to "Default Service."

SB 221 provides consumers with three options to obtain generation supply: (1) bilateral contracts with competitive retail electric service ("CRES") providers;[65] (2) governmental aggregation,[66] and (3) the standard service offer ("SSO").[67] By their position that Rider RRS relates to "default service," the Companies improperly consider that term to be synonymous with SSO service. The terms are not one and the same, but are distinguished in R.C. 4928.141 and 4928.14. While customers can ***voluntarily*** elect to receive the "SSO service" set by an MRO or ESP proceeding pursuant to R.C. 4928.141, "default service" is the service that consumers receive ***involuntarily*** as the result of their competitive supplier no longer being able to provide service for the reasons described in R.C. 4928.14. To meet the "default service" criterion of R.C. 4928.143(B)(2)(d), Rider RRS must relate to an event of default described in R.C. 4928.14. It does not. As with the Companies' "bypassability" argument above, their "default service" argument is overly broad. If involuntary "default service" were interpreted synonymously with voluntary "SSO service" (as the Companies suggest), any conceivable provision could be included in an ESP proceeding because it would relate to the SSO service being established. Such a broad construction violates *CSP II*. Thus, the Companies' "default service" argument must fail.

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[64] *See Ohio Power*, Order (February 25, 2015), at 22.

[65] R.C. 4928.08.

[66] R.C. 4928.20.

[67] R.C. 4928.141.

c. R.C. 4928.143(B)(2)(d) Does Not Provide for "a Financial Limitation on the Consequences of Customer Shopping."

i. Background

R.C. 4928.143(B)(1) requires an EDU to include provisions in its proposed ESP relating to the supply and pricing of electric generation service. Because the Company's SSO is fully supplied by a competitive bid process under R.C. 4928.143(B)(1), the Companies are precluded from arguing that its purchased power agreement will serve as a "physical" hedge to the supply of electric generating service under R.C. 4928.143(B)(1). Instead, it must adopt the position that Rider RRS is a "financial" hedge…and the fiction that R.C. 4928.143(B)(2)(d) permits a ***financial*** limitation on customer shopping.

In *Ohio Power*, the Commission distinguished between a "physical" limitation on customer shopping (*i.e.*, a constraint on a customer's ability to switch generation service to a CRES provider), and a "financial" limitation. The Commission reasoned that under the PPA rider, 5 percent of a customer's bill would be based on the cost of service of the OVEC units and 95 percent on the "retail market."[68] Thus, the Commission considered a "financial limitation on customer shopping" to occur when customers' bills do not reflect pricing that relies 100% on the competitive retail market. The Commission explained, "[e]ffectively…the proposed PPA rider would function as a "***financial restraint on complete reliance on the retail market***" for the pricing of retail electric generation service.[69] Rehearing on this issue remains pending before the Commission.

[68] *Ohio Power*, Order (February 25, 2015) at 22.
[69] Id.

*ii. **Common usage of the term "customer shopping" is synonymous with the term "customer switching" and reveals the General Assembly's intent under R.C. 4928.143(B)(2)(d) only to permit provisions in an ESP that would limit customer switching.***

Key to the determination whether Rider RRS constitutes a "limitation on customer shopping" is the interpretation of this phrase and, specifically, whether the phrase contemplates a "physical" or a "financial" limitation on customer shopping. Resolution requires a determination of legislative intent. In this regard, R.C. 1.42 provides:

> Words and phrases shall be read in context and construed according to the rules of grammar and common usage. Words and phrases that have acquired a technical or particular meaning, whether by legislative definition or otherwise, shall be construed accordingly.

Initially, it must be observed that the Ohio Revised Code,[70] as well as Commission and Ohio Supreme Court precedent, are replete with references that use the term "shopping" synonymously with the word "switching."[71] Common usage dictates that the term "customer shopping" refers to customers who physically "switch" to CRES providers.

To accept the Companies' position, the Commission is required to read the word "financially" into the statute. Indeed, to accept the Companies' position, the Commission would be required to change the entire wording of the statute from permitting "limitations of customer shopping" to permitting a "***<u>financial limitation on the consequences of customer shopping.</u>***" Recently addressing the rules of statutory construction in Commission proceedings, the Ohio Supreme Court stated:

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[70] See, *e.g.*, R.C. 4928.40(A)(1) ("…such ***<u>shopping incentives</u>*** by customer class as are considered necessary to induce, at the minimum, a twenty per cent load ***<u>switching rate by customer class</u>*** halfway through the utility's market development period but not later than December 31, 2003." [Emphasis added.])

[71] *In Re Ohio Consumers' Counsel*, 109 Ohio St.3d, 206-Ohio-2110, 847 N.E.2d 1184, ¶ 21; *In Re Elyria Foundry*, 114 Ohio St.3d 305, 2007-Ohio-4146, 871 N.E.2d 970, at ¶ 72.

> When interpreting a statute, a court must first examine the plain language of the statute to determine legislative intent. *Cleveland Mobile Radio Sales, Inc. v. Verizon Wireless*, 113 Ohio St.3d 394, 2007-Ohio-2203, 865 N.E.2d 1275, ¶ 12. The court must give effect to the words used, ***making neither additions nor deletions from the words chosen by the General Assembly***. *Id. See, also, Columbia Gas Transm. Corp. v. Levin*, 117 Ohio St.3d 122, 2008-Ohio-511, 882 N.E.2d 400, ¶ 19. Certainly, had the General Assembly intended to require that electric distribution utilities prove that carrying costs were "necessary" before they could be recovered, it would have chosen words to that effect.[72] [Emphasis added.]

The Companies' proposed addition of the word "financial" to the statute contravenes its plain meaning and the intent of the General Assembly to provide the Commission only with the authority to limit customer switching to CRES providers. Thus, the proper interpretation of the phrase at issue is that an ESP may include a provision relating to limitations on customers switching to a CRES provider.

A determination that R.C. 4928.143(B)(2)(d) permits a "financial" limitation on customer shopping contravenes legislative intent, as determined by R.C. 1.42, and is unlawful. Moreover, without its express inclusion in the items listed in R.C. 4928.143(B)(2)(a)-(i), such a financial limitation on customer shopping is forbidden by *CSPII.*

d. Rider RRS Does Not Provide Stability or Certainty.

The Companies' witness Strah contends that Rider RRS will provide distribution customers rate stability and certainty. First, he relies on the alleged protections Rider RRS will provide in times of extreme weather, such as the Polar Vortex that occurred in January 2014.[73] Mr. Strah's contention is based on the premise that, at times of low market prices, customers may be charged the difference between PJM market prices and the PPA Unit costs. But when

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[72] *In Re Columbus S. Power*, 138 Ohio St.3d 448, 2014-Ohio-462, 9 N.E.3d 1064, ¶ 26.

[73] Companies Ex. 13 (Strah Direct) at 8, 12.

market prices are high, customers could receive the profits from the sale the PPA Units' generation. However, as OCC/NOPEC witness Wilson explained, proposed Rider RRS would be updated annually and the net Rider RRS amounts incurred in one year would not appear on a customer's bill until the next year as a credit or charge. Dr. Wilson testified that, due to this lag, it is likely that the annual Rider RRS updates could move in the same direction as forward market rates. Thus, there is no assurance that Rider RRS would move in the opposite direction as the market and, further, it cannot be assumed that the Rider RRS will tend to hedge or stabilize customers' rates.[74] Indeed, the likelihood that the rider will move in the same direction of market prices will only exacerbate price volatility for consumers, rather than produce rate stability.

Dr. Wilson also testified that SSO customers would be served under staggered supply contracts established through periodic competitive auctions. These blended SSO rates would reflect forward prices at the time of the auction and, forward prices for delivery periods a few years out tend to be stable, resulting in fairly stable rates over time. Dr. Wilson also explained that customers taking service under contracts with CRES suppliers could choose offerings (including fixed price contacts) that control how their electric supply would be priced as market prices rise and fall, balancing cost, risk and other considerations.[75]

The Companies' witness Strah attempted to dismiss these legitimate methods to mitigate market fluctuation by stating that the SSO and CRES contracts are not long-term solutions. He reasoned that the SSO was limited to the three-year term of an ESP, that CRES contracts are typically offered for a period of one year and that no CRES contracts were offered for a period

[74] OCC/NOPEC Ex. 4 (Wilson Direct) at 13, 50.
[75] Id.

greater than three years.[76] Mr. Strah's testimony, which was offered before the Third Stipulation and Recommendation was offered in this proceeding, ignores that the proposed ESP term is now eight years. Moreover, Mr. Strah failed to consider the effect of Rider RRS on large-scale governmental aggregation.[77] Had he done so, he would have learned that NOPEC, which serves approximately a third of the customers in the CEI and OE service territories, has an existing contract with FES to serve its aggregation members for a period of *nine* years – longer than ESP IV's proposed eight year term.[78] The publicly available terms of this competitively bargained-for contract show that NOPEC's residential customers pay a fixed 6% off their EDU's price to compare. This is significant because Mr. Strah testified that the Companies' residential customers would pay a charge under Rider RRS during the first three years of the ESP (2019), but they would not receive a 6% credit on their bill until 2029 (which now is 5 years after ESP IV would end).[79]

Under their existing FES contract, NOPEC residential customers *already* are receiving a 6% discount. Moreover, under NOPEC's existing contract with FES, NOPEC residential customers will enjoy their 6% discount whether market prices increase or decrease, unlike under Rider RRS. Mr. Strah's testimony confirms that Rider RRS does not benefit NOPEC's customers, who have successfully mitigated the effect of prices increases in the competitive market, as the legislature intended. NOPEC customers would derive no benefit by giving up

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[76] Companies' Ex. 4 (Strah Direct) at 11, 13.

[77] Such consideration is required by R.C. 4928.20(K).

[78] Tr. XXII at 4591 (Wilson Re-Cross Examination).

[79] Companies Ex. 13 (Strah Direct) at 12.

their negotiated discount to the price to compare during the first three years of ESP IV.[80] This is especially so, considering that Dr. Wilson has shown that Rider RRS will never provide distribution customers a bill credit, but will cost NOPEC's customers over $400 million over the eight-year term of ESP IV, and all customers up to $3.6 billion.[81] Rider RRS provides only costs and no benefits to NOPEC's customers.

B. Rider RRS is Unlawful Because it Harms Large Scale Governmental Aggregations by Imposing a Nonbypassable Generation Charge. R.C. 4928.20(K).

R.C. 4928.20(K) was enacted as a part of SB 221. It provides:

> The commission shall adopt rules to ***encourage and promote large-scale governmental aggregation in this state***. For that purpose, the commission shall conduct an immediate review of any rules it has adopted for the purpose of this section that are in effect on the effective date of the amendment of this section by S.B. 221 of the 127th general assembly, July 31, 2008. ***Further, within the context of an electric security plan under section 4928.143 of the Revised Code, the commission shall consider the effect on large-scale governmental aggregation of any nonbypassable generation charges, however collected***, that would be established under that plan, except any nonbypassable generation charges that relate to any cost incurred by the electric distribution utility, the deferral of which has been authorized by the commission prior to the effective date of the amendment of this section by S.B. 221 of the 127th general assembly, July 31, 2008. [Emphasis supplied.]

In assessing the effect of the nonbypassable Rider RRS on large-scale governmental aggregation, the Companies did no more than assume governmental aggregation customers would be subject to the same risks and alleged delayed benefits as all other customers.[82] Indeed, Companies witness Ruberto testified that the Companies performed no studies on the effect of

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[80] As stated above, this Rider RRS charge equals $427.04 in CEI's service territory, and $413.94 in OE's service territory through 2019 for a typical NOPEC residential customer. This would equal over $200 million for all of NOPEC's 500,000 customers, combined, during through 2019. OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 13.

[81] Id.

[82] Application, Companies Ex. 1 at 21; Companies Ex. 7 (Mikkelsen Direct) at 31.

Rider RRS on large-scale governmental aggregations such as NOPEC.[83] The Companies' analysis is meaningless because it merely restates the obvious: the effect of a nonbypassable charge is that it is applied to all customers. The legislature clearly understood as much and intended more by creating this special statutory provision.

In historical context, large-scale governmental aggregation has been an important part of Ohio's retail electric market design since SB 3 became effective in 2001, and has provided an important choice to residential and small commercial customers. The Commission's market monitoring reports show that approximately 66%, 65% and 72% of residential sales in Ohio Edison ("OE"), Toledo Edison ("TE"), and Cleveland Electric Illuminating ("CEI") companies services territories, respectively, are from a CRES provider. Moreover, the NOPEC aggregation supplies approximately 500,000 customers, or nearly one-third of the residential and commercial customers in the CEI and OE service territories.[84] To date, NOPEC's electric aggregation program has saved NOPEC residential and small commercial customers hundreds of millions of dollars.

It is against this backdrop that the legislature enacted special provisions and protections in SB 221 to encourage and promote governmental aggregation in this state, including protecting large-scale governmental aggregation from an ESP's interference with the generation rates agreed upon between the governmental aggregator and its chosen supplier. Significant for this proceeding, NOPEC has contracted with the Companies affiliate, FES, to supply full-requirements electric service to its aggregation for a *nine* year period, from January 1, 2011 through December 31, 2019 – longer than the eight-year term of the proposed ESP and Rider RRS in this case. The publicly available terms of the contract show that residential customers

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[83] Tr. XXIII at 2871-2872 (Ruberto Direct).

[84] IGS Ex. 13 (White Supplemental Direct) at 6.

pay a fixed 6% off their EDU's price to compare, and small commercial customers pay a fixed 4% off the price to compare during the contracts' nine year term.[85] The NOPEC contract demonstrates that the proposed Rider RRS is unlawful and unreasonable for the following reasons.

As the legislature intended, NOPEC has successfully arranged, on its own, to hedge against potential volatile price increases by (1) basing its contract upon the SSO price of service and (2) reducing that price by a fixed 6% for residential customers and a fixed 4% for small commercial customers. By basing the NOPEC price on the SSO's price to compare, NOPEC has taken advantage of the laddered SSO auctions that will provide price stability for its customers. NOPEC has further provided for price stability by arranging a fixed percent off the price to compare. Unlike Rider RRS, this percent off the price to compare will apply whether market prices for electricity increase or decrease or in the future. And, unlike under Rider RRS, when market prices are low, NOPEC customers are not subject to a surcharge and, indeed, receive the benefit of the same fixed percent off the PTC for an even lower rate.

As the legislature intended, NOPEC (and FES initially) embraced the competitive marketplace to provide consumers with an innovative nine-year contract that resulted in real and extensive savings in their electric rates. However, this PPA proposal now attempts to change the bargain FES struck with NOPEC. NOPEC customers currently are paying FES for full-requirements generation service through 2019. It is uncontroverted that, if Rider RRS were approved, NOPEC's customers would be required to pay an additional amount for this same generation service in the form of the nonbyassable Rider RRS – effectively paying twice – until

[85] Tr. XXII at 4591 (Wilson Re-cross). The Companies did not contest these terms, but only argued that they were confidential. Tr. XXII at 4592-4594. These terms are publicly available as reported by FirstEnergy Corp.'s own news release. http://www.prnewswire.com/news-releases/firstenergy-solutions-and-nopec-enter-into-nine-year-agreement-78317142.html.

their contract through NOPEC expires on December 31, 2019.[86] In considering the effect of the nonbypassable Rider RRS on large-scale governmental aggregation customers, the Commission must conclude that NOPEC customers will be harmed by paying this unbargained-for surcharge, that Rider RRS does not encourage or promote large-scale governmental aggregation, and that it is unlawful.

C. Rider RRS is Not in the Public Interest Because it Will Impose Enormous Costs – Up to $3.6 Billion – on the Companies' Captive Distribution Customers.

Companies witness Ruberto estimated the annual net revenues and costs to be recovered through Rider RRS.[87] These estimates were based on the revenue and cost calculations prepared by Companies witness Lisowski,[88] which were based on the 2014 price forecasts of Companies witness Rose.[89] Under the application as filed August 4, 2014, during the initially proposed 3-year term of the ESP (2016 through 2019), the Companies' distribution customers would pay a total of $420 million under Rider RRS for FES's generation related costs. Under the initial application, Rider RRS was to extend through 2031, and the Rider RRS analysis showed that revenues would begin to exceed costs in 2019 and provide a net benefit of $2 billion from Rider RSS for the fifteen year period from 2016 through 2031.[90]

In his direct testimony, OCC/NOPEC witness Wilson explained that the Companies' Rider RRS analysis was unreliable due to the speculative nature of the price assumption the analysis used.[91] Specifically, he testified that the Companies' forecasts were based upon the assumption that electricity, natural gas, and capacity prices would rise dramatically in the

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[86] OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 13; Companies Ex. 33 (Ruberto Direct) at Att. JAR-1.

[87] Companies Ex. 33 (Ruberto Direct) Ex. JFW-1.

[88] Companies Ex. 21 (Lisowski Direct).

[89] Companies Ex. 17(Rose Direct).

[90] OCC/NOPEC Ex. 4 (Wilson Direct) at 9; Companies Ex. 33 (Ruberto Direct) at Att. JAR-1.

[91] OCC/NOPEC Ex. 4 (Wilson Direct) at 11.

coming years and that these assumptions were inconsistent with market participants' expectations as reflected in forward market prices for natural gas and electric energy. In addition, he testified that because capacity prices only provide the "missing money" not provided by energy prices, it would be unlikely that capacity and energy prices would both increase sharply at the same time, as the Companies' Rider RRS analysis assumed.[92]

Dr. Wilson presented an analysis under three scenarios based upon differing natural gas and electric price assumptions.[93] The first assumed that natural gas prices would rise roughly as suggested by the U.S. Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") 2014 "Reference Case," and that energy prices would change correspondingly.[94] The second assumed that natural gas prices would follow the AEO 2014 "High Oil and Gas Resource" scenario. The third assumed that natural gas prices follow the pattern reflected in current forward prices, and rise by inflation in the out years.

Dr. Wilson concluded that, under the proposed 15-year term of Rider RRS:

- total savings to customers would be $0.2 billion per year, under the first, or Reference Case, analysis,;
- total costs to the Companies' consumers would be $3.0 billion, under the second, or High Oil and Gas Resource, analysis; and
- total costs to the Companies' customers would be $3.9 billion, under the third, Forward Price, analysis.

Dr. Wilson considered the second and third alternative scenarios more likely to occur. Moreover, he showed that, because Rider RRS would simply pass through the PPA costs to captive distribution customers, the Companies would have no incentive to manage costs or

[92] OCC/NOPEC Ex. 4 (Wilson Direct) at 11.

[93] Dr. Wilson accepted the Companies' remaining assumptions. OCC/NOPEC Ex. 5 (Wilson Supplemental) at 3; OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 3.

[94] OCC/NOPEC Ex. 4 (Wilson Direct) at 11.

maximize revenues. This would allow generation that might be uneconomic to continue in operation for many years, resulting in even higher costs to consumers in the future.[95]

When the Companies filed their Third Stipulation on December 1, 2015, they proposed to increase the term of the ESP from three to eight years, and decrease Rider RRS from 15 to 8 years. Companies witness Rose did not update his 2014 price forecast analysis to support the Third Stipulation. Instead, the Companies witness Mikkelsen supported Rider RRS's costs and benefits merely with mathematical calculations of its costs (under the same, stale projections) for an eight year term, rather than a 15 year term, and revised the return on equity for the projected fixed cost forecast. Under the outdated 2014 analysis, the Companies allege that Rider RRS will provide its customers a benefit of $ 561 million over the eight-year term of ESP IV.

However, OCC/NOPEC witness Wilson updated the three scenarios he presented in his direct testimony. He included in his analysis the Companies' potential $100 million credit provision commencing in year five of the ESP, and its updated return on equity.[96] Moreover, his analysis conservatively estimated price projections because he adopted the Companies witness Rose's forecasted capacity prices, even though evidence shows that current capacity prices are sufficient to attract new entry generation; and he accepted the Companies' plant fixed costs assumptions, despite concern that the Companies and its affiliates would have no incentive to control costs.[97] His revised analyses show the following:

- Under the first (or Reference Case) analysis, he updated his projections using the U.S. Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") 2015 "reference case," instead of the 2014 reference case. He concluded that customers would roughly break even, with a projected credit over the eight years of $0.05 billion. However, because the

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[95] OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 3.

[96] OCC/NOPEC Ex. 9, (Wilson Second Supplemental) at 6-7, 11.

[97] OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 13.

2015 AEO analysis was prepared in early 2015, he considered it outdated.[98]

- Under the second (or "High Oil and Gas Resource") analysis, Dr. Wilson substituted the AEO 2014 High Oil and Gas Resources analysis with the AEO 2015 analysis. Under this scenario, his analysis concludes that Rider RRS would cost customers $2.7 billion over eight years.
- Under the third (or "Forward Price") analysis, he updated current forward prices and inflation factors with data from December 2015, which showed that Rider RRS would cost consumers $3.6 billion over eight years.

In addition, Dr. Wilson concluded that Rider RRS would cost a typical customer consuming up to 1000 kWh per month up to $130 per year and between $798 and $836 over the ESP's eight year term.[99] Dr. Wilson's updated and current analysis of the cost impact of Rider RSS is more reliable than the 2014 analysis conducted by the Companies, which alleges that customers will receive a net benefit of $561 million over the eight year ESP. The enormous cost that Rider RRS would impose on the Companies' customers clearly is not in the public interest and must be rejected for this reason alone.

In *Ohio Power*, the Commission also was faced with widely varying estimates of the costs of Rider RRS,[100] and was unable to reasonably determine the rate impact of the similar PPA rider with any degree of certainty.[101] Concerned that the proposed rider would result in net costs to customers, with little offsetting benefits, the Commission ordered AEP Ohio to provide

[98] The potential $100 million credit proposed by the Companies did not come into play in this first analysis, only in the second and third analyses. OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 8.

[99] OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 12-13.

[100] In addition to Dr. Wilson's analysis showing a charge to customers of up to $3.6 billion, 3P/EPS witness Kalt projected a net present value loss to captive customers of as much as $ 858 million. 3P/EPS Ex. 12 (Kalt Second Supplemental) at 17. Moreover, Exelon Generation Company, LLC has offered to provide the same amount of energy and capacity at prices that would save consumers between $2 billion and $2.5 billion over the ESP IV term. This offer demonstrates the magnitude of the above-market costs that the Company's customers would bear if Rider RRS were approved. ExGen Ex. 4 (Campbell Second Supplemental) at 6.

[101] *Ohio Power*, Order (February 25, 2015) at 24.

it with additional information to review its proposal.[102] By Entry of March 23, 2015 in this proceeding, the Commission ordered the Companies to submit the same information. The information included the following four factors:

1) The financial need of the generating plant;
2) The necessity of the generating facility, in light of future reliability concerns, including supply diversity;
3) A description of how the generating plant is compliant with the pertinent environmental regulations and its plan for compliance with pending environmental regulations; and
4) The impact that a closure of the generating plant would have on electric prices and the resulting effect on economic development within the state.

In addition, the Commission ordered the Companies to include in their ESP:

1) A plan for rigorous oversight of Rider RRS, including a proposed process for a periodic substantive review and audit;
2) A commitment to full information sharing with the Commission and its Staff;
3) An alternative plan to allocate the rider's financial risk between both the Companies and its ratepayers; and
4) A severability provision that recognizes that all other provisions of its ESP will continue in the event that the rider is invalidated, in whole or in part, by a court of competent jurisdiction.

As set forth below, the Companies have failed to meet these requirements, further requiring that Rider RRS be rejected.

1. The Companies Have Not Demonstrated a Financial Need for the PPA Units.

NOPEC notes that the PUCO has not defined what is meant by the term "financial need." However, the Companies have failed to demonstrate that the PPA Units would be retired absent approval of Rider RRS and, thus, have failed to demonstrate financial need.[103]

[102] *Ohio Power*, Order (February 25, 2015) at 24-25.

The PPA Units' financial need is met as long as they recover avoidable costs.[104] The definition of "avoidable costs" used in PJM provides:[105]

> Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, and particularly the delivery year… Avoidable costs may include annual capital recovery associated with investments required to maintain a unit as Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR).

While "avoidable costs" includes necessary future investment, Companies witness Moul overstates the PPA Units financial need by including costs associated with past, sunk investments in his analysis of financial viability. Companies witness Moul overstates the PPA Units financial needs.[106] Moreover, the Companies recovered past, sunk investments through transition charges from 2001 through 2010 in the amount of nearly $7 billion ($6,911,427,628).[107] Because the Companies have failed to show that the PPA Units are not recovering their avoidable costs, they have failed to show that the Units have financial need.

2. The Companies Have Not Demonstrated Necessity of the PPA Units

a. The PPA Units are not necessary to maintain supply diversity.

The Companies repeatedly assert that the PPA Units are needed to ensure diversity of generation fuel supply.[108] Without the PPA Units,[109] the Companies argue, Ohio's generation

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[103] 3P/EPS Ex. 12 (Kalt Second Supplemental) at 7.

[104] OCC/NOPEC Ex. 5 (Wilson Supplemental) at 22-23.

[105] Monitoring Analytics, LLC, *2014 State of the Market Report for PJM*, Section 5 Capacity, p. 198.

[106] OCC/NOPEC Ex. 5 (Wilson Supplemental) at 23; see, also, OMAEG Ex. 18 (Hill Supplemental) at 7-8.

[107] OCC Ex. 25 (Rose Direct) at 18.

[108] *See* Companies Ex. 13 at 7.

[109] *See* Tr. Vol. IV, p. 75, lns. 8-24 (Companies witness Strah testifying that the Companies have not concluded that the PPA Units will actually be retired if Rider RRS is not approved); *see also* Tr. XI, p. 2337, lns. 12-21 (Companies witness Moul testifying that no generation deactivation requests to PJM have been submitted for either Davis Besse or Sammis).

portfolio will continue to become "increasingly dominated" by natural gas-fired generation.[110] Such assertions are contrary to fact.

The primary fuel used for electricity generation in the state of Ohio is coal. In 2012, the state of Ohio had 19,268 MW and 9,461 MW of generating capacity that used coal and natural gas, respectively, as its primary fuel source. These represented 59 percent and 29 percent of the generating capacity installed in the state, respectively.[111] The Companies refuse to indicate whether they believe Ohio's current generation mix reflects optimal diversity.[112]

By comparison, approximately 38 percent and 33 percent of PJM's installed capacity is coal and natural gas generation, respectively.[113] The Companies, despite suggesting that Ohio's supply diversity will be at risk if the PPA Units close, refuse to offer an opinion on the portion of coal-fired generation that is actually needed to maintain supply diversity.[114] Again, the Companies refuse to offer an opinion on what amount of natural gas-fired generation is too great.[115]

The PPA Units include 3,319 MW of coal-fired generation capacity in the state of Ohio.[116] These plants do not increase the diversity of generation technologies and fuels used in the state of Ohio in any meaningful way. If the 3,319 MW of coal-fired generators included in

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[110] *See* Companies Ex. 28 at 8; *see also* Company Ex. 14 at 4.

[111] OCC/NOPEC Ex. 1, at 28-29; *see also* Sierra Club Ex. 7, showing that in 2014, 67.67 percent of Ohio's generation output was coal, with 17.59 percent of Ohio's generation output was from natural gas-fired generation.

[112] *See* Tr. Vol. XI at 2311 (Companies witness Moul testifying that he does not have an opinion on whether Ohio's current generation mix is optimal).

[113] Companies Ex. 76, PJM 2015 State of the Market Report.

[114] Tr. IV at 752 (Companies witness Strah admitting that he does not know what level of coal generation is required for the stability of Companies' delivery system); *see also*, Tr. Vol. XI at 2254 (Companies witness Moul refusing to quantify what percent of coal the Companies believe Ohio will need to have in order to have sufficient resource diversity).

[115] Tr. XI at 2312 (Companies witness Moul stating that he does not know what percentage of gas-fired generation would be too high in Ohio).

[116] This excludes the 1,304 MW coal-fired Cliffty Creek Plant, which is part of OVEC, but is located in Indiana and the 900-MW Davis-Besse nuclear power plant.

the PPA Units were retired and replaced with 3,319 MW of natural gas-fired generation, coal and natural gas would instead represent 49 percent and 39 percent of the installed generation portfolio, respectively.[117] In many respects, this would be a more balanced and diversified portfolio of generation technologies than maintaining the coal-fired generators in the PPA Units. This is consistent with state policy as stated under R.C. 4928.02(C), which requires the Commission to ensure diversity of supplies and suppliers.

b. PJM continues to maintain and improve market-based incentives for existing efficient sources of capacity to remain in the system and to attract new investments in order to maintain adequate supply.

A subsidy to the PPA Units is not necessary because PJM maintains reliability of the electric power system within its footprint through market-based mechanisms. PJM supplements the energy and ancillary service revenues earned by generators in the day-ahead and real-time markets through its Reliability Pricing Model ("RPM") market. The RPM market is a capacity market that ensures there are sufficient capacity resource products available to maintain system reliability.

The RPM market provides incentives for existing efficient sources of capacity to remain in the system and to attract new investments. The RPM market includes performance criteria for participating generators. To receive capacity payments, generators must clear the competitive auction and be available to deliver capacity and energy when called upon by PJM. Otherwise, non-compliant generators face financial penalties for non-performance. The design of the RPM market has evolved over time, and PJM has demonstrated that it will make modifications to the market design to address changing reliability needs of customers.

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[117] OCC/NOPEC Ex. 1 (Sioshansi Direct) at 28-29.

For example, PJM proposed significant revisions to the RPM market to address potential reliability issues raised by the extremely cold weather experienced in January and February of 2014. PJM proposed to increase the performance incentives for capacity resources to be available when needed most, help reduce price spikes during system emergencies, and reduce the chance of expensive forced outages (the "PJM Capacity Performance Proposal)."[118] FERC subsequently approved, with modification, the PJM Capacity Performance Proposal.[119]

Companies Witness Rose agrees that PJM's Capacity Performance product is "a major structural change in the PJM capacity market."[120] Through the Capacity Performance product, "PJM seems to have achieved the goal of designing incentives so that bidding resources are actually likely to become operational, and therefore that capacity clearing in the market will be present and on schedule."[121] Companies Witness Rose agrees that PJM's Capacity Performance product should result in more capacity becoming operational in PJM.[122] In sum, PJM has made structural reforms to ensure that sufficient capacity resources are available to maintain system reliability—and Companies Witness Rose agrees. Rider RRS is not needed for this purpose.

Rider RRS is not consistent with competition in the PJM wholesale power market.[123] Allowing subsidized generators to participate in a wholesale market against unsubsidized assets destroys the price signals provided by the market. In turn, the benefits of a properly functioning competitive wholesale market, outlined above, are destroyed.

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[118] IMM Ex. 1 at 2.

[119] Order on Proposed Tariff Revisions, FERC, 151 FERC ¶ 61,208 (June 9, 2015).

[120] Tr. XXXV at 7229.

[121] Sierra Club Ex. 87 at 8, IFC International, *New Regime, New Results: Insights from Recent PJM Auctions* (2015).

[122] Tr. XXXV at 7253.

[123] IMM Ex. 1 at 3.

c. The PPA Units are not necessary to ensure reliability during a 'winter event' similar to the Polar Vortex.

The Companies repeatedly reference the winter event of January 6-8, 2014 (the "Polar Vortex") in support of the need to subsidize the PPA Units. Specifically, the Companies argue that during the Polar Vortex, many interruptible natural gas generation assets were unable to perform.[124] The coal and nuclear baseload generation provided by the PPA Units, the Companies argue, are needed to ensure stability for customers in the event of future weather similar to the Polar Vortex.[125]

The Companies' reliance on the 2014 Polar Vortex to demonstrate the necessity of the PPA Units is flawed. During the Polar Vortex, according to PJM, "[a]ll conventional forms of generation, including natural gas, coal and nuclear plants were challenged by the extreme conditions."[126] PJM sustained a high level of forced outages during the Polar Vortex. However, more outages were due to equipment failure rather than fuel interruptions.[127] Although natural gas fired generation accounted for 47 percent of unavailable megawatts due to forced outages, coal generation accounted for 34 percent.[128]

Moreover, the Companies' reliance on the 2014 Polar Vortex inappropriately discounts the system improvements made by PJM subsequent to the Polar Vortex. The winter of 2015 was marked by cold temperatures similar to the winter of 2014.[129] In fact, PJM set a new wintertime peak demand record in the winter of 2015, surpassing the previous record from the previous

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[124] Companies' Ex. 13 at 8.

[125] Id. at 8-9

[126] Sierra Club Ex. 8 at 24, "PJM 2014 Winter Report."

[127] Id. at 25.

[128] Id.

[129] IGS, Ex. 1 at 5, "PJM 2015 Winter Report."

winter.[130] However, generators performed better in the winter of 2015 than during the Polar Vortex, despite colder temperatures and greater demand.[131] PJM met its new all-time winter peak, with internal capacity and interchange without the need for emergency demand response, shortage pricing, emergency energy purchases, or emergency procedures beyond a cold weather alert.[132] PJM also maintained its reserve requirements at all times.[133] According to PJM:

> The performance improvements of winter 2015 over 2014 are attributed to steps PJM and generator owners initiated after the winter of 2014 experience: pre-winter operational testing for dual-fuel and infrequently run unit, a winter preparation checklist program, better communication of fuel status and increased coordination with gas pipelines.[134]

In addition to these effective short-term measures, PJM implemented structural reforms to ensure long-term generation performance improvements, in the form of its Capacity Performance product, discussed in greater detail in the preceding section.

d. The PPA Units are not necessary because new, more efficient plants are being built in Ohio.

At least five new combined-cycle natural gas power plants are under development in Ohio. The Ohio Power Siting Board has approved the Oregon Clean Energy Center (Case No. 12-2959-EL-BGN), the Carroll County Energy Generation Facility (Case No. 13-1752-EL-BGN), the Middletown Energy Center (Case No. 14-0534), and Clean Energy Future-Lordstown (Case No. 14-2322-EL-BGN).[135] The application for the South Field Energy Electric Generating

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[130] Id.

[131] Id.

[132] Id. at 6.

[133] Id.

[134] Id. at 5-6.

[135] *See* NOPEC/OCC Ex. 5 (Wilson Supplemental) at 10-11; OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 4; *see also*, Opinion, Order and Certificate, Case No. 13-2322-EL-BGN (September 17, 2015).

Facility (Case No. 15-1716-EL-BGN) is under review by Ohio Power Siting Board.[136] Indeed, as OCC/NOPEC witness Wilson observed, "The fact that several new gas-fired power plants are coming to Ohio should be no surprise, as the nation's fastest growing new source of low-cost natural gas is the Utica shale formation, located primarily in Eastern Ohio.[137]

Combined, the new projects under development will bring more than 3,600 MWs of new, efficient, and reliable combined-cycle natural gas generation to Ohio. Moreover, in total, these new projects will bring more than $4.1 billion of new direct investment to Ohio.[138] New, efficient, and reliable combined-cycle natural gas generation facilities are being successfully developed and built in Ohio without any ratepayer subsidies.

3. The Companies Have Not Established How the PPA Units are Compliant with All Pertinent Environmental Regulations and Their Plan for Compliance with Pending Environmental Regulations.

On August 3, 2015 U.S. EPA released the final Clean Power Plan ("CPP") which specifies carbon dioxide emission rate guidelines for existing stationary generation sources. States must develop plans to comply with the Clean Power Plan. Final plans are due to EPA by 2018, at which point EPA will review them to determine if they will achieve the required standards. Uncertainty remains regarding the form of the final form of CPP and how states,

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136 OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 5.

137 OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 5. See, U.S. Energy Information Administration, *Drilling and Productivity Report*, December 2015.

138 *See In the Matter of the Application of Oregon Clean Energy, LLC for a Certificate of Environmental Compatibility and Public Need to Construct an Electric Generation Facility*, Case 12-2959-EL-BGN, Opinion, Order, and Certificate, at 20 (May 1, 2013); *In the Matter of the Application of Carroll County Energy, LLC for a Certificate of Environmental Compatibility and Public Need to Construct an Electric Generation Facility*, Case No. 13-1752-EL-BGN, Opinion, Order, and Certificate, at 19 (April 28, 2014); *In the Matter of the Application of NTE Ohio, LLC for a Certificate of Environmental Compatibility and Public Need to Construct an Electric Generation Facility*, Case No. 14-534-EL-BGN, Opinion, Order, and Certificate, at 13 (Nov. 24, 2014); and *In the Matter of the Application of Clean Energy Future, LLC for a Certificate of Environmental Compatibility and Public Need to Construct an Electric Generation Facility*, Case No. 14-2322-EL-BGN, Opinion, Order, and Certification, at 21 (Sept. 17, 2015).

including Ohio, will choose to comply.[139] In general, the impact of CPP is expected to drive movement to gas-fired generation (versus other fossil sources) at a faster rate than would otherwise occur.[140] Likewise, renewables and demand side alternatives are expected to be more attractive resources from both a cost and emissions perspective. The Companies have not established whether the Sammis generating units will perform under the CPP.[141]

4. The Companies Have Failed to Show that Closure of the PPA Units Would Have an Adverse Impact on Electric Prices and a Resulting Adverse Impact on Economic Development.

Companies' Witness Murley conducted a study on the economic impact of the Sammis and Davis-Besse plants. The study relies upon plant level data supplied by FES, along with "multipliers" derived from a regional economic impact model. Using this approach, the study identifies the economic impact of the plants in terms of total jobs and economic output.

As an initial matter, Witness Murley's study has aspects that can be misunderstood and may be misleading. First, the economic "output" of the plants cited by Witness Murley is mostly a measure of the value of generation supply from selling power into the PJM at the two plants.[142] This is not a useful measure of economic impact, and removal of these values dramatically lowers the asserted adverse economic impact of the plants' retirement.[143] Second, Witness Murley's study assumes that if Davis-Besse shuts down, then all employees and contractors are laid off immediately, with no additional considerations.[144] Witness Murley entirely fails to

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[139] This uncertainty continues, and may be exacerbated by the United States Supreme Court's recent stay of the Clean Power Plan in in *West Virginia, et al., Applicants v. Environmental Protection Agency, et al,* Application for Stay 15A773 (February, 2016).

[140] Sierra Club Ex. 95, Ex. TFC – 44 at 50.

[141] *See* Sierra Club Ex. 73.

[142] OCC/NOPEC Ex. 7 (Kahal Direct) at 45 ("For Sammis, this is $502 million out of a total of $586 million.").

[143] Id. (asserting that "[a] far more valid measure is the modeled impact on personal income, which totals about $170 million for both plants combined (inclusive of multiplier effects)"—a much lower figure than the asserted adverse impact of $1 billion).

[144] Id.

consider that if Davis-Besse were to close, there would first be a decommissioning process that would be an enormous undertaking, requiring significant economic resources, including a large on-site staff and contractors.[145] As a result, Davis-Besse would remain a considerable source of economic activity even if it were to close.[146]

Notably, there is no evidence in the Companies' case indicating a likelihood that the PPA Units will actually retire. Companies' witness Rose's wholesale price projections provide a very healthy return of and on legacy capital, as well as an additional surplus of $2 billion over the initial 15 year term of Rider RRS.[147] OCC/NOPEC witness Wilson's testimony makes clear that prices must be substantially lower than witness Rose's projections to warrant retirement.[148] According to the Companies' own projections, market revenues will be sufficient to keep the plants economical without the need for Rider RRS.[149]

However, in the event that wholesale market prices turn out to be substantially lower, Companies' Witness Murley's study is fundamentally flawed because it gives no consideration to the far reaching adverse impacts of Rider RRS if FES and the Companies insist on *continued* operation for uneconomic plants. In a scenario with very low wholesale market prices, Rider RRS could allow the plants to survive, albeit with significant ratepayer subsidization reflected in increased retail electric rates—all while the Companies earn guaranteed profits.[150]

Importantly, witness Murley's study ignores the fact that retail electric rate increases have a significant detrimental impact on the service area economics of the Companies. Large electric rate increases can adversely affect the local economy through several mechanisms.

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[145] Id.

[146] Id.

[147] Id. at 38.

[148] Id.

[149] Id. at 39.

[150] OCC/NOPEC Ex. 7 (Kahal Direct) at 39.

Residential customers would have less disposable income, thereby having less to spend in the local economy.[151] For residential customers, the Rider RRS is analogous to experiencing a tax increase but with no corresponding benefit in the form of more public services. Commercial customers may respond to retail rate increases due to Rider RRS by raising prices to cover the added cost of doing business.[152] As noted by OCC/NOPEC witness Kahal, "[t]his effect further reduces the net disposable income of the households in the [Companies'] service area, furthering reducing employment through multiplier impacts."[153]

Ohio's critical manufacturing sector will also be adversely affected by Rider RRS.[154] Ohio's manufacturers must compete with other manufacturers regionally, in the U.S., and globally. Retail rate increases impair their competitiveness, thereby further reducing local employment.[155] Witness Murley's study gives no consideration to the far reaching adverse ripple impacts of Rider RRS on the northern Ohio economy that could occur if the Companies insist on continued operations for uneconomic plants and Ohio employees are faced with large electric increases.

5. ESP IV Does Not Provide for Rigorous Commission Oversight, Including Periodic Substantive Review and Audit.

The Companies' purchase power agreement with FES and related Rider RRS lack traditional regulatory oversight. Notably, the proposal does not provide for the Commission to do a prudence review of its legacy costs embedded in past decisions by FES.[156] Moreover, the

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[151] Id. at 42.

[152] Id.

[153] Id.

[154] *See* OMAEG Ex. 17 at 5 (noting that in 2010, Ohio had the highest level of manufacturing activity among the Midwestern states).

[155] OCC/NOPEC Ex. 7 (Kahal Direct) at 42.

[156] OCC Ex. 25 (Rose Direct) at 4

proposal does not allow a for a prudence review going forward.[157] The proposal falls short of the oversight associated with traditional cost of service regulation. In addition, the Third Supplemental Stipulation contains no provision that would allow the Commission to require changes to the PPA if the Commission finds that any of the PPA's provisions to be unreasonable. In sum, the Companies wish to be guaranteed cost recovery and a rate of return without the accompanying oversight.

6. The Companies Do Not Commit to Full Information Sharing with Commission and Staff.

The Third Supplemental Stipulation falls well short of a commitment to full information sharing with the Commission and Staff. First, FES, a party to the resulting PPA if Rider RRS is approved, is not a party to the stipulation. FES allegedly made a verbal commitment to participate in information sharing,[158] but no document memorializing FES's commitment to information sharing was filed as part of the Third Supplemental Stipulation.[159] Moreover, OVEC has also made no commitment to share information with the Commission as part of the Third Supplemental Stipulation.[160] Further, if Rider RRS is approved, the Companies will not file the subsequent PPA agreement between the Companies and FES with the Commission.[161] Nor do the Companies intend to file the PPA agreement with FERC,[162] leaving a regulatory gap with no real oversight over the PPA agreement.

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[157] Id.

[158] Tr. XXXVI at 7520.

[159] Id.

[160] Tr. XXXVI at 7521.

[161] Tr. XXXVI at 7620.

[162] Tr. XIII, at 2869.

7. The Companies Have Not Provided an Adequate Alternative Plan to Allocate the Rider RRS' Financial Risk Between the Companies and its Ratepayers

As initially proposed, all of the PPA Units' actual costs net of market revenues will be passed through to retail customers. The application provides no incentive for the Companies and the PPA Units' owners to control costs or maximize revenues. The Companies failed to propose an alternative plan to allocate Rider RRS's financial risk between the Companies and the ratepayers in their initial application.

The Third Stipulation also fails to propose an adequate alternative plan to allocate Rider RRS's financial risk between the Companies and ratepayers. The $100 million credit offered by the Companies in the Third Stipulation simply reduces costs to customers. The credit does nothing to change the fact that all of the PPA Units' actual costs net of market revenues after the credit will be passed to customers. Thus, after the total credit amount, all risk remains imposed on customers.[163]

In addition, the credit offered by the Companies does nothing to incentivize the Companies and owners of the PPA Units to control costs and maximize market revenue. Under the second and third pricing scenarios offered by OCC/NOPEC witness Wilson, Rider RRS's cost to customers is greater than the maximum credit in each year, so the full credit is always applied. As long as it is clear that the cost to customers will be greater than the maximum amount of the credit, which is expected, the credit will have no impact at all on the Companies' lack of economic incentive to manage the PPA units effectively or to maximize market value. At the margin, the Companies will still pass all incremental costs, revenues and net costs through to customers. Only under circumstances where the net cost in a year could be less than the

[163] OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 9, 19.

maximum credit would the credit provide any incentive to minimize cost and maximize revenue.[164]

OCC/NOPEC witness Wilson offered an appropriate risk sharing proposal that NOPEC urges the Commission to adopt if it approves Rider RRS.[165] Under this proposal, only 50% of the net charges under Rider RRS would be imposed upon customers during the first three years of ESP IV. Thereafter, the cost allocation would change to 25% for customers and 75% for the Companies. The asymmetric sharing would continue until customers were made whole for the costs and risks of sharing under the first years of the arrangement. This alternative would help the PPA Units bridge through the next few years and customers might eventually realize a net benefit if prices rises so much to make the PPA Units economic.

8. Severability provision

In accordance with *Ohio Power*, the Commission required the Companies in this proceeding to commit to continue all provisions of ESP IV in the event that Rider RRS were overturned in whole or in part by a court of competent jurisdiction. The Commission's intent was that the Companies' customers continue to enjoy the benefits of the ESP. As discussed below, the Stipulation contains a "Transition Provision" that would permit Riders RRS and DCR to continue for the full eight-year term, even if ESP IV were terminated after four years under R.C. 4928.143(E). Companies witness Mikkelsen testified that, in such event, while the Companies would continue to collect the Rider RRS and Rider DCR revenues after ESP IV's termination, the Companies would cease providing shareholder funds for economic development and low income assistance under the Stipulation.[166] The Transition Provision of ESP IV subverts

[164] OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 18.

[165] *See* OCC/NOPEC Ex 4 (Wilson Direct) at 6-7.

[166] Tr. XXXIV (Mikkelsen Cross) at 7563-7564.

the Commission's intent to ensure that consumers continue to obtain the benefits of the ESP during its full term. NOPEC submits that if ESP IV is terminated under R.C. 4928.143(E), Riders RRS and DCR must be terminated as well.

D. Rider RRS is Unlawful Because It Requires Customers to Fund an Unlawful, Anti-competitive Subsidy Under R.C. 4928.02(H).

R.C. 4928.02(H) provides that it is the policy of this state to:

> Ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, ***including by prohibiting the recovery of <u>any</u> <u>generation-related costs through distribution or transmission rates.</u>*** [Emphasis supplied.]

Rider RRS is a distribution rate under the authority of *In Re Ohio Power Company*, Case No. 10-1454-EL-RDR Finding and Order (January 11, 2012) (the "*Sporn Case*"). In the *Sporn Case*, AEP Ohio sought to recover the closing costs associated with its Sporn Unit 5 generating facility through a stand-alone rider, the Plant Closure Cost Recovery Rider ("PCCRR"). The costs included the unamortized balance plant balance that remained on AEP Ohio's books (approximately $56.1 million). Thus, the PCCRR rider clearly was a rate to recover the costs of generation-related service. However, AEP Ohio sought to recover the charge from all distribution customers as a non-bypassable charge, and it characterized the rider in its application as a "distribution" charge.

In the *Sporn Case*, the Commission recognized that whether a charge is to be classified as a distribution rate is dependent upon the class of customers to which it is applied. If a charge is applied to all distribution customers, it is considered a distribution rate. In the *Sporn Case*, the Commission disallowed the PCCRR, finding:

> Additionally, the Commission notes that [AEP Ohio's] recovery of the closure costs would be contrary to the state policy found in

> Section 4928.02, Revised Code. That policy requires the Commission to avoid subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service***. [AEP Ohio] seeks to establish a nonbypassable charge that would be collected from all distribution customers by way of the PCCRR***.[167] [Emphasis added.]

In this proceeding, under the *Sporn Case* precedent, the nonbypassable Rider RRS would also be charged to all distribution customers and, thus, be considered a distribution charge. The plain language of R.C. 4928.02(H) prevents the Commission from allowing recovery of ***<u>any</u>*** generation-related costs through distribution rates. Because Rider RRS charges all distribution customers for the cost of the PPA Units' generation, it is considered to be a distribution rate and is prohibited by R.C. 4928.02(H).[168]

1. The subsidy customers are being asked to pay is anti-competitive.

Rider RRS creates an anti-competitive subsidy by requiring all of the Companies' customers to underwrite the costs of the PPA Units generation. Rider RRS requires ratepayers to guarantee that the PPA Units' generation earn a profit by covering the difference in the revenues from the sale of the power and the cost of generation. This guarantee is a benefit to FES, which owns Sammis and Davis Besse, and an interest in OVEC. In other words, it's a subsidy to FES regardless of whether it produces a credit for retail customers in any particular year. It is a benefit that other competitive retail or wholesale providers do not enjoy, and thus is anti-competitive.

Moreover, OCC/NOPEC witness Sioshansi recognizes other anti-competitive consequences of the Rider RRS. He explains that the rider could incentivize the Companies to

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[167] *See Ohio Power*, Order (February 25, 2015) at 19.

[168] See *In Re Elyria Foundry Company*, 114 Ohio St.3d 305, 2007-Ohio-4164, 871 N.E.2d 1176,

cause lower-cost power from the PPA Units to be withheld from the market to the benefit of the Companies' affiliated unregulated generation in PJM.[169]

Rider RRS is unlawful under Ohio law because it provides an anti-competitive subsidy to FES.

E. The Companies' Request to Count Legacy MTEP Costs Towards the ESP II Non-Collection Commitment Should be Rejected Because it is Premature and Contrary to the Stipulation in the ESP II Case.

In Case No. 10-388-EL-SSO ("*ESP II Order*"), the Companies agreed not to seek recovery through retail rates $360 million of Legacy PJM Regional Transmission Expansion Plan costs ("Legacy RTEP") paid by the Companies (the "ESP II Non-Collection Commitment").[170] The Companies now propose to count MISO Transmission Expansion costs ("Legacy MTEP") toward the ESP II Non-Collection Commitment in the event that FERC determines that Legacy MTEP costs are not permitted in the ATSI formula rate tariff. That issue is currently before the FERC.[171]

If FERC approves changes to the PJM Tariff to include Legacy MTEP costs in the ATSI rate formula, then the Companies' request in this proceeding is moot. Inclusion of the Legacy MTEP costs in the ATSI formula will allow PJM to charge those costs to the Companies. In turn, the Companies can recover these costs charged by PJM from its Ohio retail customers through the Companies' Non-Market-Based Services Rider.[172] The Companies have indicated a belief that ATSI will ultimately be allowed by FERC to include the Legacy MTEP costs in its

[169] OCC/NOPEC Ex. 1 (Sioshansi Direct) at 16-17 .

[170] *ESP II Order* (August 25, 2010) at 13.

[171] Companies Ex. 7 (Kahal Direct) at 18.

[172] OCC Ex. 19 (Hixon Direct) at 7.

formula.[173] It is, therefore, unnecessary for the Commission to consider the Companies' proposal in this proceeding.

The Companies' request to count Legacy MTEP costs toward the Legacy RTEP non-collection commitment is also directly contrary to the ESP II stipulation. The ESP II Combined Stipulation included the following provision:

> The Companies agree not to seek recovery through retail rates for MISO exit fees or PJM integration costs from retail customer of the Companies. The Companies agree not to seek recovery through retail rates of legacy RTEP costs for the longer of: (1) during the period of June 1, 2011 through May 31, 2016; or (2) when a total of $360 million of legacy RTEP costs ***have been paid by the Companies <u>and</u> <u>not</u> recovered by the Companies*** through retail rates from Ohio customers.[174]

(Emphasis added.)

The Companies' now seek to dilute this benefit by proposing to count Legacy MTEP costs toward the ESP II Non-Collection Commitment, *even though the Companies will not be charged these costs*.[175] The language of the ESP II Order clearly states that the costs to be counted toward the Non-Collection Commitment shall be costs *charged to* the Companies *and not recovered by* the Companies. Additionally, the Commission noted that, when approving the Combined Stipulation, the Companies had committed to "*forgo recovery* of a minimum of $360 million of legacy RTEP charges."[176] (Emphasis added.) In order to "forgo recovery" of costs, the Companies must be charged those costs in the first place.

[173] Transcript I at 169.

[174] *ESP II Order* (August 25, 2010) at 13.

[175] The Companies have made payments of just over $80 million for PJM Legacy RTEP that they have not attempted to recover from Ohio retail customers. The remaining ESP II Non-Collection Commitment, therefore, is approximately $280 million of Legacy RTEP charges. This is the continuing benefit of avoided charges to which the Companies' Ohio customers are entitled. OCC Ex. 19 (Hixon Direct) at 5.

[176] *ESP II Order* (August 25, 2010) at 36.

In the ESP II proceeding, the Companies classified the commitment not to seek recovery of the $360 million of Legacy RTEP costs, paid for by the Companies but not recovered through retail rates, as a reason that the proposed ESP II was more favorable in the aggregate as compared to the expected results of a MRO. The Commission relied on these assertions when determining that the proposed ESP II was more favorable in the aggregate as compared to the expected results of a MRO.[177] The Companies' current proposal contradicts the Companies' assertions in ESP II.

IV. ESP IV IS NOT MORE FAVORABLE THAN A MARKET RATE OFFER. R.C. 4928.143(C)

A. The Commission's Standard of Review in ESP Proceedings

R.C. 4928.141 provides that an electric distribution utility may seek approval of a market rate offer ("MRO") or ESP as its SSO. R.C. 4928.142 and 4928.143 specify the standards for MROs and ESPs, respectively. 4928.143(C)(1) sets forth the standard that the Commission must follow when approving an electric distribution utility's proposed ESP:

> …the commission by order shall approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan so approved, including its *pricing and all other terms and conditions*, including any deferrals and any future recovery of deferrals, *is more favorable in the aggregate* as compared to *the expected results that would otherwise apply under [an MRO derived under] section 4928.142 of the Revised Code*. (Emphasis supplied.)

In attempting to sustain its burden under this statutory provision, Companies witnesses Mikkelsen and Fanelli performed an analysis of the ESP v. MRO test, considering three elements: (1) the SSO price of generation to customers (R.C. 4928.143(B)(1)); (2) other quantifiable provisions (R.C. 4928.143(B)(2)), and (3) qualitative provisions (for which there is no statutory authority). Under the Companies' analysis, these three elements are combined (in

[177] *ESP II Order* (August 25, 2010) at 42.

the “aggregate”) and compared to the results that would be obtained under R.C. 4928.142, if the SSO were proposed in the form of an MRO. From this comparison, the Companies assert that the proposed ESP, in the aggregate, is more favorable than an SSO in the form of an MRO.[178]

The Commission also has used this analysis in its review under R.C. 4928.143(C)(1), and NOPEC currently is challenging such analysis in the Ohio Supreme Court.[179] The appeal specifically concerns whether the language “in the aggregate” permits the Commission to consider the qualitative (or non-quantifiable) benefits of a proposed ESP, in addition to its quantifiable costs. The legislative history of 2007 Am.Sub.S.B. 221, Effective July 31, 2008 (“SB 221”), and the Court’s precedent show that the Commission is limited to considering quantifiable costs only.

1. The Legislative History of SB 221[180]

R.C. 4928.143(C)(1) was enacted as a part of SB 221, which underwent significant changes in the Ohio Senate and House after being introduced in the Senate on October 4, 2007. This history shows that the legislature has consistently intended the SSO as an MRO to be a market-based price developed through a competitive bidding process, and that the SSO as an ESP be a cost-based price. The ESP price evolved over the various versions of SB 221 from a traditional rate base/cost of service analysis based upon the valuation of its facilities and costs to

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[178] Companies Ex. 50 (Fanelli Direct) at 7; Companies Ex. 155 (Mikkelsen Fifth Supplemental) at 10-14.

[179] Ohio Supreme Court Case No. 13-513.

[180] NOPEC is aware that this Ohio Supreme Court has stated in the past that “no legislative history of statutes is maintained in Ohio.” See *State v. Dickinson*, 28 Ohio St.2d 65, 67, 275 N.E.2d 599 (1971) (“*Dickinson*”). However, R.C. 1.49 specifically sanctions the examination of “legislative history,” and the Court has done so before and after *Dickinson*. See *Caldwell v. State*, 115 Ohio St. 458, 154 N.E. 792 (1926), and *Griffith v. Cleveland*, 128 Ohio St.3d 35, 2010-Ohio-4905, 941 N.E.2d 1157 (2010) (examining the documents maintained on the Ohio General Assembly’s web site). Copies of the Senate and House versions of SB 221, and related bill analyses of the Legislative Service Commission are all linked on the Ohio General Assembly’s website at http://www.legislature.state.oh.us/analyses.cfm?ID=127_SB_221&ACT=As%20Enrolled, and are contained in the Appendix to this Initial Brief.

provide service, to one that permits a utility to propose a pricing methodology, which price could be adjusted through the additional cost items provide in R.C. 4928.13(B)(2).

As introduced, the legislation was structured such that the either an MRO or ESP could be approved if the Commission deemed them just and reasonable, and they complied with the state policies contained in R.C. 428.02.[181] However, the legislation, as passed by the Senate, the standard for approving an MRO changed significantly and required not only a finding that the offer and price were just and reasonable and compliant with R.C. 4928.02, but also that the price determined for each customer class under the MRO was to be "more favorable than, *or at least comparable to*," the price for each customer class under an ESP. (Emphasis supplied.)[182] However, in the version of the legislation as reported by the House, the legislature significantly expanded the costs that could be recovered through the ESP under R.C. 4928.143(B)(2). Accordingly, it placed a check on the costs to be recovered under an ESP, as a consumer protection provision, such that the ESP's costs could not be greater than the price resulting from an MRO. Moreover, the legislature removed the state policy considerations from the criteria the Commission may consider under the ESP v. MRO test.[183] The processes for developing the MRO and ESP remained essentially the same in the version of SB 221 as Passed by the General Assembly, except that the standard of review importantly required that the ESP be "more favorable" than an MRO.[184]

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[181] See Appendix A. SB 221 as Introduced, Section 4928.14(B)(1), Legislative Service Commission Bill Analysis, 127th General Assembly, SB 221: As Introduced. SB 221 as Passed in the Senate, Section 4928.14(D)(1).

[182] See Appendix B. SB 221 as Passed in the Senate, Section 4928.14(D)(1); Legislative Service Commission Bill Analysis, 127th General Assembly, SB 221: As Passed by the Senate.

[183] See Appendix C. SB 221 as Reported in the H. Public Utilities, Section 4928.143(B)(1); Legislative Service Commission Bill Analysis, 127th General Assembly, SB 221: As Reported by the H. Public Utilities.

[184] See Appendix D. SB 221 as Passed by the General Assembly, Section 4928.143(C)(1); Legislative Service Commission Bill Analysis, 127th General Assembly, SB 221: As Passed by the General Assembly.

2. The Ohio Supreme Court's Precedent

The Ohio Supreme Court has had two opportunities to interpret the scope of items that could be considered in reviewing an ESP. First, it recognized that the nine provisions listed in R.C. 4928.143(B)(2)(a)-(i) require the Commission to make a quantitative determination. It recognized that eight of the items "implicitly require" the Commission to consider "certain costs." *In Re Application of Columbus Southern Power Co., et al*., 128 Ohio St. 3d 402, 2011-Ohio-958 [¶26], 945 N.E.2d 501 (hereinafter, "*CSP I*"). The ninth item (R.C. 4928.143(B)(2)(e) (App. Appx. at 214.) also requires a quantitative analysis because it permits an automatic increase in any component of the "price" of an ESP.[185]

In a later decided case, the Commission recognized that all nine of the R.C. 4928.143(B)(2) factors provided for "cost recovery" and limited the items to be considered by the Commission in approving an ESP only to those cost provisions specifically enumerated. *In Re Application of Columbus Southern Power Co., et al*., 128 Ohio St. 3d 512, 2011-Ohio-1788 [¶¶ 31-35], 945 N.E.2d 655 (hereinafter, "*CSP II*").

Considered together, the cases show that the Commission can modify the "price" in R.C. 4928.143 (B)(1) by considering cost of service factors, if it so chooses. *CSP I*. The Commission also can modify the "costs" to be recovered in the ESP under R.C. 4928.143(B)(2)(a)-(i). What

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[185] To be clear, the Court in *CSP I*, at ¶ 27, stated:

> Moreover, while it is true that the commission must approve an electric security plan if it is 'more favorable in the aggregate' than an expected market-rate offer…that fact does not bind the commission to a strict price comparison. On the contrary, in evaluating the favorability of a plan, the statute instructs the commission to consider 'pricing and all other terms and conditions.' Thus, the commission must consider more than price in determining whether an electric security plan should be modified.

This language cannot be construed to mean that the Commission may look at an unlimited number of factors in addition to "price." Rather, as construed by *CSP II*, infra, it becomes clear that the Commission is limited in its analysis to consider the items listed in R.C. 4928.143(B)(1) and (2), e.g., the price contained in R.C. 4928.143(B)(1) and the cost factors listed in R.C. 4928.143(B)(2), as discussed subsequently.

the Commission cannot do is add additional items to be considered in this quantitative analysis, including qualitative items. *CSP II*.

3. The Rules of Statutory Construction Require that R.C. 4928.143(C)(1) Be Construed Consistent with Legislative Intent. R.C. 1.49.

The Legislature intended, and this Court confirmed, that the Commission is limited, in reviewing an ESP, to considering the quantitative factors listed in R.C. 4928.143(B) (the "price" in R.C. 4928.143(B)(1) and the "costs" in R.C. 4928.143(B)(2)). Accordingly, R.C. 4928.143(C)(1) must be construed consistent with that intent. R.C. 1.49. R.C. 4928.143(C)(1) provides in part:

> …the commission by order shall approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan so approved, including its *pricing and all other terms and conditions*, including any deferrals and any future recovery of deferrals, *is more favorable in the aggregate* as compared to *the expected results that would otherwise apply under [an MRO derived under] section 4928.142 of the Revised Code*. (Emphasis supplied.) [App. Appx. at 215.]

A review of this provision makes clear that the term "pricing" is a reference to the price to be proposed in R.C. 4928.143(B)(1), while the reference to "all other terms and conditions" refers to the specifically enumerated items for which cost recovery can be had under R.C. 4928.143(B)(2)(a)-(i), because no other items may be considered in reviewing an ESP. *CSP II*. The Commission's charge is then to consider whether the ESP price and costs, combined (i.e., "in the aggregate") are "more favorable" than the price developed through a competitive bidding process under the MRO provisions contained in R.C. 4928.142.

4. Appropriate Application of the ESP v. MRO

The Companies performed the traditional analysis of the ESP v. MRO test,[186] which considers three elements: (1) the SSO price of generation to customers,[187] (2) other quantifiable provisions,[188] and (3) qualitative provisions. In addressing the test's first element, the Companies contend that the SSO price of generation to customers would be established through the competitive bid process under R.C. 4928.143(B)(1) and would be equivalent to the results that would be obtained under the MRO provided in R.C. 4928.142.[189] NOPEC does not disagree with the Companies' analysis.

As stated above, the legislative history and statutory construction of R.C. 4928.143 do not permit the Commission to consider "qualitative" benefits in performing the ESP v. MRO test. Indeed, as explained below, the "qualitative" benefits alleged by the Companies are confused with the "public benefit" analysis the Commission performs when considering partial stipulations. Specifically, the legislative history of R.C. 4928.143 demonstrates that the state policy provisions of R.C. 4928.02, which form the bases for the public benefit analysis, is not to be included in the ESP v. MRO test.[190]

Accordingly, whether the Companies' proposed ESP is more favorable in the aggregate than an MRO rests on a determination of whether the identifiable costs of the ESP are greater than the cost of an MRO.

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[186] R.C. 4928.143(C)(1).

[187] R.C. 4928.143(B)(1).

[188] R.C. 4928.143(B)(2).

[189] Companies Ex. 50 (Fanelli Direct) at 7.

[190] See Appendix C. SB 221 as Reported in the H. Public Utilities, Section 4928.143(B)(1); Legislative Service Commission Bill Analysis, 127th General Assembly, SB 221: As Reported by the H. Public Utilities.

a. The Quantitative Analysis

The following table provides a comparison of the competing quantifiable costs of ESP IV as developed by the Companies and OCC/NOPEC:

The Companies' versus NOPEC's Quantitative Benefits Comparison (in millions)		
	The Companies[191] (Nominal)	NOPEC/OCC[192] (Nominal)
Economic Development Funding	($ 24.0)	($ 24.0)
Low Income Funding	($ 19.1)	($19.1)*
Customer Advisory Agency Funding	($ 8.0)	($8.0)*
Rider DCR	$ 0	$ 240 to $330
Rider GDR	$ 0	N/A
Rider RRS	($ 561.0)	$2,713
TOTAL	**($ 612.1)**	**$ 2,902 to $ 2,992**
*OCC/NOPEC witness Kahal provisionally accepted Low Income Funding and Customer Agency Funding as quantifiable costs of ESP pending further review. OCC/NOPEC Ex. 11 (Kahal Second Supplemental) at 18. The items, however, do not fall with the limited items permitted in an ESP per CSP II and should not be considered quantitative benefits.		

NOPEC submits that the Companies proposed ESP IV in this case is about $3 billion less favorable than an MRO.

i. It is Unlawful to Include Rider GDR in an ESP and Unreasonable to Value the Placeholder GDR at Zero.

As stated previously, only those items that are expressly listed in R.C. 4928.143(B) may be included in an ESP. The Companies propose the implementation of a new Government Directives Rider ("Rider GDR") to recover costs related to future government directives. The

[191] Companies Ex. 155 (Mikkelsen Fifth Supplemental), at 12

[192] OCC/NOPEC Ex. 11 (Kahal Second Supplemental) at 27, Ex. 11-A at 1.

proposed Rider GDR does not meet any of the nine elements of R.C. 4928.143(B)(2). Thus, it should be disallowed.

However, the Companies seek approval of the rider as a placeholder, with an initial rate of zero, which will be populated with costs during the eight-year ESP as governmental directives are issued. Because the rider currently would be set at zero and unidentified cost recovery would occur in future ESP years, Ohio's consumers currently are precluded from considering the rider's costs. Without presently knowing how the rider may be quantified in the future, the Commission cannot consider, and consumers cannot reasonably contest, under R.C. 4928.143(C)(1), whether the ESP is more favorable than an MRO. The Companies seek to unreasonably and unlawfully shelter review of Rider GDR's costs to be collected during the ESP's term for purposes of the statutory test. Moreover, the Commission's approval of the placeholder rider prevents the Companies from sustaining their burden of proof that the ESP is more favorable than an MRO under R.C. 4928.143(C)(1). Accordingly, the placeholder Rider GDR must be disallowed or, alternatively, absent the ability to quantify Rider GDR, the entirety of the Companies' ESP rejected.

In addition, the Commission should reject this premature placeholder rider for several reasons, consistent with the Commission's denial of similar premature placeholder riders in other recent ESP cases.[193] First, the Companies do not provide a list of the costs or accounts they would seek to recover through Rider GDR, thereby creating an open-ended recovery vehicle for any costs that the Companies may incur. If the Companies believe that programs required by legislative or governmental directives would increase costs and cause a revenue deficiency, then

[193] *See In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143, in the Form of an Electric Security Plan*, Case No. 13-2385-EL-SSO, Opinion and Order (Feb. 25, 2015), p. 63, where the Commission rejected AEP's proposed placeholder for potential NERC compliance and cybersecurity costs as premature.

the Companies should file a rate case to recover the costs related to the directives.[194] The Companies should not be able to recover the costs associated with the legislative or governmental directives absent a showing that any such costs actually cause revenue deficiencies.[195]

Rider GDR is also asymmetric, which compounds the excessive earnings concerns of single-issue ratemaking.[196] Under Rider GDR, the Companies have no obligation to file for rate reductions resulting from changes in governmental regulations. Additionally, because the Companies have far more information about their operations than the Commission, it would be difficult for the Commission to ensure that the utilities are fully compliant with their obligation to flow through cost reductions to customers. [197]

ii. Rider DCR revenues are quantifiable costs of the ESP

The Companies propose to continue the Delivery Capital Recovery Rider ("Rider DCR") during the period of ESP IV, with a modification to increase the revenue caps for Rider DCR.[198] Specifically, the Companies propose that the revenue caps for Rider DCR will increase annually by: $30 million for the period June 1, 2016 through May 31, 2019; $20 million for the period June 1, 2019 through May 31, 2022, and $15 million for the period June 1, 2022 through May 31, 2024. To be sure, these increases pertain only to annual increases to the allowable caps. Thus, with the increases, the annual caps would increase from $210 million in the 2016-2017 PJM

[194] OCC Ex. 18 (Effron Direct) at 23.
[195] Id.
[196] OCC/NOPEC (Kahal Direct) Ex. 7 at 34.
[197] Id.
[198] Application, Company Ex. 1 at 13.

planning year to $ $390 million in the 2023-2024 PJM planning year – and total $2.595 billion during the eight year term of ESP IV.[199]

OCC/NOPEC witness Kahal demonstrated that revenues associated with Rider DCR were a quantifiable cost of the ESP.[200] However, the Companies refuse to quantify these costs as a part of the ESP v. MRO test, asserting that the revenue requirements associated with the recovery of incremental distribution investments should be considered to be the same whether recovered through the ESP or through a distribution rate case conducted in conjunction with an MRO.[201]

The Companies' position misstates the statutory test found in R.C. 4928.143(C)(1), which requires the Commission to compare "the electric security plan so approved…to the expected ***results that would otherwise apply under section 4928.142 of the Revised Code***." Emphasis added. The plain meaning of the statute clearly limits the Commission's analysis to the "expected results" of R.C. 4928.142, and does not contemplate consideration of the results of a distribution rate case.[202]

Moreover, the Companies' interpretation requires one to read into the statute words to the effect that the approved ESP should be compared to the expected results under R.C. 4928.142 **and a distribution rate case**. In considering the rules of statutory construction, the Ohio Supreme Court has found:

> When interpreting a statute, a court must first examine the plain language of the statute to determine legislative intent. *Cleveland Mobile Radio Sales, Inc. v. Verizon Wireless*, 113 Ohio St.3d 394, 2007-Ohio-2203, 865 N.E.2d 1275, ¶ 12. The court must give effect to the words used, ***making neither additions nor deletions***

[199] Tr. XXXVI at 7573-7575 (Mikkelsen Cross).

[200] OCC/NOPEC Ex. 7 (Kahal Direct) at 23-24.

[201] Companies Ex. 50 (Fanelli Direct) at 7.

[202] R.C. 1.42.

> ***<u>from the words chosen by the General Assembly</u>***. *Id. See, also, Columbia Gas Transm. Corp. v. Levin*, 117 Ohio St.3d 122, 2008-Ohio-511, 882 N.E.2d 400, ¶ 19. Certainly, had the General Assembly intended to require that electric distribution utilities prove that carrying costs were "necessary" before they could be recovered, it would have chosen words to that effect.[203] [Emphasis added.]

Clearly, the Companies' interpretation of the statute adds to the words chosen by the General Assembly. Had the General Assembly intended to include the expected results of a distribution rate case in the statutory test, it would have so stated.

iii. The Commission should reject the continuation of Rider DCR and instead require the Companies to commence a base distribution rate case.

Alternatively, the Commission should reject the continuation of Rider DCR and instead require the Companies to commence a distribution rate case. Consistent with the Companies' ESP II and ESP III cases, Rider DCR is being proposed in ESP IV in combination with a base distribution rate freeze until June 1, 2024.[204] The Companies' last base distribution rate case was in 2007. The 2007 rate case established the Companies' authorized rate of return of 8.48 percent and return on equity of 10.5 percent, which the Companies intend to use for Rider DCR.[205] Since 2007, with interest rates at near all-time lows and stock prices at all-time highs, capital costs today are at historic lows.[206] The authorized rate of return and return on equity should reflect these low capital costs. The continuation of Rider DCR is a mechanism that enables the Companies to avoid having their authorized rates of return scrutinized, as would occur in a base rate case. This avoidance of scrutiny of the Companies is detrimental for customers, who pay the rate of return.

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[203] *In Re Columbus S. Power*, 138 Ohio St.3d 448, 2014-Ohio-462, 9 N.E.3d 1064, ¶ 26.

[204] Id.

[205] OCC/NOPEC Ex. 7 (Kahal Direct) at 30.

[206] OCC Ex. 22 (Woolridge Direct) at 3.

In addition, riders such as Rider DCR can lead to increases in utility rates and revenues, even when a company does not have a revenue deficiency.[207] The calculations of OCC witness Effron indicate that the Companies' earned returns in 2013 "well in excess of what could reasonably be considered an adequate return, based on returns authorized by the PUCO, as well as other utility commissions, in recent years."[208] As witness Effron states, "[t]he purpose of Rider DCR should allow the [Companies] to avoid revenue deficiencies resulting from additions to utility plant in service, not perpetuate or augment excess earnings."[209] The Companies' witnesses concerning Rider DCR, witnesses Mikkelsen and Fanelli, do not refute witness Effron's calculations.[210]

Moreover, the Companies fail to demonstrate why increases to the revenue caps for Rider DCR are required to maintain reliability. The Companies track and measure their reliability performance against Commission approved reliability performance standards which have been effective since 2010.[211] The Companies indicate that their actual reliability performance has consistently outperformed their reliability standards from 2010.[212] In fact, the Companies admit that they are presently placing "sufficient resources to the reliability of their distribution systems."[213]

The Companies fail to justify the need for increased revenue caps for Rider DCR. The Companies presented no specific distribution capital project or projects that justify the increase.

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[207] OCC Ex. 18 at 10.

[208] Id. at 11; *see also* OCC Ex. 18 at 17, "Based on that authorized ROE and the ROE's that I have calculated, OE has excess revenues of $58.9 million annually, CEI has excess revenues of $60.6 million annually, and TE has excess revenues of $15.6 million annually."

[209] OCC Ex. 18 at 11.

[210] *See* Company Ex. 7; *see also* Company Ex. 50.

[211] Company Ex. 8 at 8, noting that reliability standards were approved in Case No. 09-759-EL-ESS.

[212] Id. at 9.

[213] Id. at 10.

Instead, the Companies vaguely reference the need to "continue to make necessary infrastructure investments in their distribution system," without detailing the types of investments that would justify a doubling of the annual revenue cap increase.[214] Considering that the Companies are already exceeding their reliability performance standards, it is not clear why the revenue cap increases are necessary.

At the time of ESP IV's expiration, as proposed in the Third Supplemental Stipulation and Recommendation, at least 17 years will have passed since the Companies' last rate case. The electric utility industry is dynamic and a number of significant changes can and will occur within that period. A comprehensive, periodic review of each company's finances is necessary to ensure that all costs are being appropriately incurred and recovered. NOPEC strongly urges the Commission require the Companies to file rate cases as soon as practicable in lieu of the Rider DCR mechanism. A rate case permits the overall earnings of the Companies to be reviewed along with all of its revenues and expenses, and it is a prudent regulatory practice to gain a proper understanding of the regulated distribution company on a regular basis.

iv. The economic development, job retention and low income funding should be excluded from the quantitative analysis.

As explained above, the Companies are quick to argue that Rider DCR costs included in an ESP are a "wash" because the same distribution costs could be recovered through a rate distribution case if an MRO were implemented. Contradicting itself, the Companies allege that the stipulated economic development, low income funding, and customer advisory agency funding costs are benefits of an ESP because they cannot be obtained in an MRO. The Companies conveniently ignore the argument it made in support of cost recovery under Rider

[214] Companies Ex. 50 at 4.

DCR – that if an MRO is implemented, the Commission may also consider the potential quantitative benefits that customers would receive through a distribution rate case. In this instance, if an MRO were implemented with a companion distribution rate case, the Companies and the parties could stipulate, as in this ESP proceeding, to provide economic development, low income funding, and customer advisory agency funding. Indeed, the Companies witness Mikkelsen admitted the ability to include these funds in a distribution rate proceeding.[215]

Moreover, the low income funding and customer advisory agency funding do not fall within the items contained in R.C. 4928.143(B) for inclusion in the ESP.[216]

v. Rider RRS should be quantified at $2.73 Billion.

In performing the statutory ESP v. MRO analysis, OCC/NOPEC witness Kahal chose to use the second of OCC/NOPEC witness Wilson's scenarios for Rider RRS. Witness Kahal's use of the second scenario ($2.73 Billion) was extremely conservative considering that Dr. Wilson's third scenario shows that Rider RRS' cost could be $3.6 Billion. Mr. Kahal's quantification is further corroborated by the offer made by Exelon Generation Company, LLC to provide the same amount of energy and capacity at prices that would save consumers between $2 billion and $2.5 billion over the ESP IV term.[217] Clearly, even accepting the Companies' claim of other quantifiable benefits in ESP IV, the enormous cost of Rider RRS requires that the Companies' ESP IV be rejected. Indeed, even if qualitative benefits could lawfully be considered a part of the ESP v. MRO test, they would not outweigh the onerous burden this cost quantitatively places on consumers.

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[215] Tr. XIII at 596.

[216] The Companies confuse the state policy in R.C. 4928.02 with the limited items that can be included in an ESP under R.C. 4928.143(B). Low income funding and customer advisory agency funding falls within state policy considerations (R.C. 4928.02(L) (protect at-risk populations)), but do not fall within the limited categories contained in R.C. 4928.143(B).

[217] ExGen Ex. 4 (Campbell Second Supplemental) at 6.

Accordingly, NOPEC requests that the Commission adopt OCC/NOPEC witness Kahal's analysis and find that the proposed ESP IV is not more favorable than an MRO.

b. Even if the Commission could consider qualitative factors in determining whether an ESP is more favorable than an MRO, it is unlawful to consider qualitative factors that fall outside of the provisions of R.C. 4928.143(B).

As stated above, qualitative benefits are not properly considered a part of the ESP v. MRO test. The Ohio Supreme Court has limited the items that can be included in an ESP to those expressly listed in R.C. 4928.143(B),[218] and the Court subsequently found that each of those items were "categories of cost recovery."[219] The statutory test, as confirmed by judicial interpretation, is meant to serve as a consumer protection provision, by limiting the rates that consumers pay under an ESP to less than those they would otherwise pay at market under an MRO. It is improper, if not unlawful, to permit qualitative benefits to override the quantitative analysis that R.C. 4928.143(C)(1) expressly requires.

Nevertheless, in this proceeding, the Companies allege that qualitative factors should be considered as benefits under the ESP. The Companies request should be rejected for the following reasons.

i. Benefits provided under R.C. 4928.02.

Many of the qualitative benefits alleged by the Companies actually are state policy considerations under R.C. 4928.02. The Companies rely on R.C. 4928.02 as independent authority to consider qualitative benefits under the ESP v. MRO test. As stated above, only items expressly listed in R.C. 4928.143(B) may lawfully be considered in an ESP. While the Commission must review an ESP to ensure that its provisions do not violate the state policies

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[218] *In Re Application of Columbus Southern Power Co., et al.*, 128 Ohio St. 3d 402, 2011-Ohio-958, 945 N.E.2d 501 (hereinafter, "*CSP I*").

[219] *In Re Application of Columbus Southern Power Co., et al*., 128 Ohio St.3d 512, 2011-Ohio-1788, 945 N.E.2d 655 (hereinafter, "*CSP II*"). .

contained in R.C. 4928.02, the state policies are not contained in R.C. 4928.143(B) and, thus, cannot be considered a part of the ESP for purposes of the test performed under R.C. 4928.143(C)(1).

The Companies have confused the ESP v. MRO test (which permits only items listed in R.C. 4928.143(B) with the test for approving partial stipulations (which considers items included in R.C. 4928.02). The Companies include many of the same items in the partial stipulation analysis when considering whether the stipulation benefits consumers and is in the public interest (see partial stipulation analysis below), as in its qualitative benefits analysis for the ESP v. MRO test.[220] Some of these items, *e.g.*, federal advocacy for a longer term capacity product, battery resource investment evaluation, a filing to transition to decoupled residential rates, and amendments to tariffs and regulations do not fall within the items listed in R.C. 4928.143(B). Moreover, additional items considered by the Companies in their direct[221] and supplemental testimonies[222] do not fall within R.C. 4928.143, including a base distribution rate freeze, assistance to at-risk populations,[223] a slower phase-out of Rider EDR(d) to allow Rate GT customers to gradually transition to market pricing, time of day pricing provisions, implemental of a supplier web portal, and changes to regulations and tariffs. Accordingly, the Commission cannot lawfully consider these items in making its analysis under the ESP v. MRO test.

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[220] Cf. the items listed in Companies Ex. 155 (Mikkelsen Fifth Supplemental) at 13, with the items listed at page 10 of the same exhibit.

[221] Companies Ex. 7 (Mikkelsen Direct) at 5, 16; Companies Ex. 50 (Fanelli Direct) at 8-10.

[222] Companies Ex. 8 (Mikkelsen Supplemental) at 12.

[223] Assistance to at-risk population is a consideration under R.C. 4928.02(L).

c. Even if the Commission could consider qualitative factors in determining whether an ESP is more favorable than an MRO, the benefits of Riders DCR and GDR are also available under an MRO and should not be considered in the ESP v. MRO test.

The Companies allege that Rider DCR provides a qualitative benefit over an MRO. Specifically, they allege that approval of Rider DCR will enable the Companies to hold base rates constant over the ESP period and make improvements to the distribution infrastructure and improve system reliability.[224]

There is no dispute among the parties that the Companies could make significant investments in its distribution infrastructure under either Rider DCR or a base rate proceeding. The significance of the amount is immaterial considering that consumers will be required to support it under either an ESP or MRO. Indeed, the enormity of this increase (up to $ 330 million),[225] granted outside of the comprehensive review of a base rate proceeding, must be considered a qualitative **detriment** to Ohio consumers.

The Companies' allegation that Rider DCR will permit them to keep base rates constant is incorrect, or at least misleading. The Third Stipulation and Recommendation permits the Companies to file for a base rate increase with Staff's approval.[226] Moreover, considering that Ohio's residential ratepayers will be required to pay for this infrastructure investment in any event, they receive no benefit whether paying it through Rider DCR or a base rate case.

Moreover, the Companies allegation Rider DCR will permit it to provide infrastructure investment more quickly than under a base rate proceeding is unreasonable. The analysis

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[224] Co. Ex. 50 (Fanelli Direct) at 9. The Companies make this same claim as to Rider GDR; however, the Companies have not identified the costs that the rider will recover or whether they would be limited to distribution costs. Thus, as stated above, the Companies have failed to show that Rider DGR is an item that can be included in an ESP under R.C. 4928.143(B). Regardless, if the Companies seek approval of Rider GDR only to recover distribution costs, it can do the same in a distribution rate case, the same as with Rider DCR as discussed below.

[225] OCC/NOPEC Ex. 11 (Kahal Second Supplement) at 23.

[226] Companies Ex. 154 at 13.

considers the qualitative benefit of consumers receiving infrastructure improvements more quickly under Rider DCR, but refuses to recognize that consumers must also pay for these improvements sooner. Instead, the Companies consider this accelerated payment under Rider DCR to be a "wash" with the payments under a base rate proceeding over time.

The Companies can't have their cake and eat it too. Clearly, Rider DCR provides accelerated benefits and customers incur accelerated costs. It is unreasonable for the Commission to consider these benefits while ignoring the costs that customers pay for them. If the Commission is to consider Rider DCR to be a benefit because it accelerates infrastructure reliability, it must recognize the accelerated payments that provide for that benefit. Otherwise, the Commission should find that the infrastructure improvements made through the DCR will "wash" over time, which they certainly will, if made pursuant to a base rate proceeding.

d. Even if the Commission could consider qualitative factors in determining whether an ESP is more favorable than an MRO, the Companies have failed to show a benefit resulting from avoided transmission costs.

The Companies witness Fanelli testified that another qualitative benefit of the ESP was the avoidance of transmission costs in the event the PPA Units are retired if ESP IV is not approved.[227] As a threshold matter, the Companies have provided no evidence that the PPA Units will be retired in such event, or that new entrant generation would not be located near the retired plants.[228] Moreover, OCC/NOPEC witness Kahal explained that reducing the term of Rider RRS from 15 to 8 years makes the likelihood of additional transmission investment remote. This is because Rider RRS would only delay new transmission investment for a few years. If the plants are uneconomic and are retired at the end of Rider RRS, the investment in new transmission

[227] Companies Ex. 50 (Fanelli Direct) at 9.
[228] OCC/NOPEC Ex. 11 (Kahal Second Supplemental) at 20.

would only be delayed. In other words, Rider RRS would not avoid, but merely delay the transmission expenses the Companies assume (but not proven) is necessary.[229] Thus, the Commission cannot consider avoided transmission costs as a qualitative benefit.

B. The Third Stipulation and Recommendation Fails the Commission's Traditional Test for Approving Partial Stipulations.

In approving partial stipulations offered to resolve proceedings before it, the Commission traditionally considers a three-prong analysis, which was endorsed by this Court in *Consumers' Counsel v. Pub. Util. Comm.*, 64 Ohio St.3d 123, 592 N.E.2d 1370 (1992):

1. Is the settlement a product of serious bargaining among capable, knowledgeable parties?
2. Does the settlement package violate any important regulatory principle or practice?
3. Does the settlement, as a package, benefit ratepayers and the public interest?

1. The Partial Stipulation Test Does Not Control Over the ESP v. MRO Test.

By enacting R.C. 4928.143(C), the legislature provided the Commission with the sole, statutory, standard to approve an ESP. As stated above, that test is strictly one of cost comparison between an ESP and MRO. If the Companies' application fails that test, the Commission can modify the proposed ESP so that it does meet the statutory standard, otherwise it must be rejected. R.C. 4928.143(C). The PUCO cannot bootstrap approval of a proposed ESP through the partial stipulation standard. Indeed, the third criteria of the partial stipulation standard is whether the stipulation violates any important regulatory principle or practice. Thus, once the Commission determines, as it should in this proceeding, that the cost of the limited items that can be included in an ESP are, in the aggregate, greater than the costs determined under R.C. 4928.142, the Commission's inquiry must end. The Commission can then modify the

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[229] OCC/NOPEC Ex. 11 (Kahal Second Supplemental) at 20-21.

ESP so that its costs are less than that of an MRO, or reject the ESP altogether. As discussed, it is unlawful to include Rider RRS as part of an ESP. However, if Rider RRS is included, the ESP must be rejected because its cost of up to $3.6 billion to consumers is outrageously more than an MRO.

C. Despite the Signatory Parties' Experience in Utility Matters Before the Commission, Serious Bargaining Did Not Occur in This Proceeding.

To support its position that the Partial Stipulation was the result of serious bargaining, the Companies testified that the signatory parties have extensive experience before the Commission.[230] NOPEC has no doubt that the Staff, the signatory parties, and their counsel are knowledgeable and capable; but, that knowledge and capability has no bearing on whether serious bargaining occurred in this proceeding.

In addition, the Companies assert that the signatory parties represent a diversity of interests.[231] To the contrary, a large number of parties with considerable experience before the Commission in ESP proceeding and with diverse interests have refused to sign stipulation. These include millions of residential customers (OCC, NOPEC, NOAC), commercial customers (OMAEG), environmental interests (Sierra Club, Environmental Defense Fund, Environmental Law and Policy Center) and CRES suppliers (PJM Power Providers, The Electric Supply Association, and Retail Energy Supply Association).[232] Accordingly, the Commission must give considerable weight to the diversity of interests opposing this partial stipulation. Considering the diversity of interests of the parties opposing the partial stipulation, this prong of the test should be given no weight.[233] Moreover, and as recognized by former Commissioner Cheryl Roberto,

[230] Companies Ex. 155 (Mikkelsen Fifth Supplemental) at 8.
[231] Id.
[232] OCC/NOPEC Ex. 11 (Kahal Second Supplemental) at 29.
[233] OCC/NOPEC Ex. 11 (Kahal Second Supplemental) at 28-30.

bargaining cannot be said to be "serious" in the context of an ESP proceeding when the EDU, here the Companies, has the statutory ability to unilaterally reject any modification to the proposed electric security plan.[234]

D. Does the settlement package violate any important regulatory principle or practice?

As discussed previously, the settlement violates R.C. 4928.143 by including Rider RRS and Rider GDR in the ESP in violation of R.C. 4928.143(B) and *CSP II*. Even if Rider RRS were properly included in ESP IV, the enormity of its costs (up to $3.6 billion) renders the ESP far less favorable that an MRO, under R.C. 4928.143(C)(1). Because the statutory test for approving ESPs has not been met, the partial stipulation must fail under this prong, and be rejected.

In addition, as a general matter, the partial stipulation departs from Ohio's long march to the orderly deregulation of the electric generation function and assets. Rider RRS is effectively the "reregulation" of generation assets, reversing Ohio's long-standing regulatory principles, policies and practice.[235] In that vein, the Stipulation is unlawful because (1) Rider RRS violates R.C. 4928.02(H) by permitting the recovery of generation-related costs through distribution rates, and (2) it violates R.C. 4928.20(K) by harming large-scale governmental aggregations with a nonbypassable charge.

E. Does the settlement, as a package, benefit customers and the public interest?

Clearly, a settlement package that shifts the risks to captive customers of up to $3.6 billion in costs for the PPA Units cannot be said to benefit customers or be in the public interest. Although some parties have chosen to become signatories to the settlement package that the

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[234]OCC/NOPEC Ex. 11 (Kahal Second Supplemental) at 6-7, citing to the Companies' 2008 ESP case, *In Re FirstEnergy*, Case No. 08-935-EL-SSO, Second Finding and Order (March 25, 2009), Roberto concurring in party and dissenting in part.

[235] OCC/NOPEC Ex. 11, (Kahal Second Supplemental) at 32.

Companies and Commission Staff bartered, most consumers, and nearly all residential and commercial consumers,[236] oppose the settlement largely because of the enormous costs it will shift to them. Those parties who joined the Stipulation, including the Companies, did so for their own private parochial self-interests and not for the public interest.

Although Companies witness Mikkelsen sponsored the Stipulation, she did not explain how its individual components benefitted companies or the public interest, other than to provide a general statement that the individual agreements with signatory parties accomplished as much.[237] Moreover, other signatory parties did not file testimony to support how their agreement to the settlement terms supported the public interest. Thus, as an initial matter, the Companies have failed in their burden of proof on this issue.

The generalizations provided by Companies witness Mikkelsen that the settlement is in the public interest are easily refuted:

1) **The settlement will provide adequate, safe, reliable and predictably priced electric service**.

This statement is an apparent reference to the PPA and Rider RRS. However, there is no evidence of record that absent the PPA and Rider RRS, the PPA Units would be retired or, more importantly, that in the PPA's absence, consumers will be without adequate, safe, reliable and predictably priced electric service.[238] As to predictable prices, CRES customers are protected by multi-year contracts. Indeed, NOPEC's contact extends for a period nine years – a year longer than the protections allegedly afforded by Rider RRS – and, as stated above, SSO customers are protected by the laddered competitive bid auctions.

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[236] OCC, NOPEC, Power4Schools and OMAEG stridently oppose the stipulation.

[237] Companies Ex. 155 (Mikkelsen Fifth Supplemental) at 10.

[238] *See* Tr. IV, p. 75 (Companies witness Strah testifying that the Companies have not concluded that the PPA Units will actually be retired if Rider RRS is not approved); *see also* Tr. XI, p. 2337 (Companies witness Moul testifying that no generation deactivation requests to PJM have been submitted for either Davis Besse or Sammis).

2) The settlement supports economic development and job retention.

Once again, this statement rings hollow considering that the record contains no evidence that the PPA Units will be retired absent the PPA and Rider RRS. Moreover, as explained above, Companies witness Murley's analysis of the economic impact related to the Sammis and Davis Besse plants is flawed and should be rejected.

3) The settlement continues the regulatory principle of gradualism.

The Companies claim of gradualism is predicated upon their unsupported speculation that electricity prices will rise significantly in years four through eight of ESP IV. However, OCC/NOPEC witness Wilson, P3/EPSA witness Kalt, and ExGen witness Campbell each provided testimony that the Companies would pay substantially more over the market price for electric under the 8 year ESP IV. OCC/NOPEC witness Wilson testified that consumers would pay up to \$3.6 billion in charges under Rider RRS; P3/EPSA witness Kalt testified that customers would be charged up to \$858 million (net present value); and ExGen witness Campbell testified that the Companies would save \$2 billion to \$2.5 billion if ExGen were to provide the same amount of energy and capacity.[239]

4) The settlement protects at risk populations through low-income programs.

Although the Companies have agreed to provide \$ 27.1 million to low-income groups through shareholder funds, this funding does not benefit the public at large, particularly when that funding comes at a cost of up to \$3.6 billion to the Companies captive ratepayers.

5) The settlement provides benefits to large industrial customers that will allow them to better compete in the global marketplace.

[239] OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 12; 3P/EPS Ex. 12 (Kalt Second Supplemental) at 17; ExGen Ex. 4 (Campbell Second Supplemental) at 6.

No evidence was presented on this record that the discounts provided to large industrial customers will allow them to compete better in the global marketplace. Moreover, these discounts will be recovered through rates further burdening all other ratepayers.

6) The settlement supports federal advocacy for improvement in the capacity markets, CO_2 emission reductions; grid modernization; and resource diversification.

Companies witness Mikkelsen alleges that the settlement "supports" various policies, projects or goals listed below. However, each requires a future filing with and approval by the Commission or other agency, or merely expresses non-binding goals or aspirations for which the Companies will not be held accountable if they are not obtained. None provide a concrete benefit to consumers in this ESP proceeding.

- Federal Advocacy – The Stipulation provides that the Companies merely shall advocate for market enhancements, such as a longer-term capacity product.[240] This advocacy provides no identifiable benefits to consumers in this proceeding. Moreover, OCC/NOPEC witness Wilson explained why PJM stakeholders have already rejected a longer-term capacity product on at least four occasions.[241]

- CO_2 Emission Reductions – The Stipulation establishes only a "goal" to decrease CO_2 emissions by at least 90% below 2005 levels by 2045. The Companies are not required to file their plan for this goal and not required to do until November 2016. Importantly, no provision is provided to hold the Companies responsible for failing, or failing to attempt, to meet these goals.[242] This emission reduction goal provides no concrete benefits to consumers.

[240] Companies Ex. 154 at 9.

[241] OCC/NOPEC Ex. 9 (Wilson Second Supplemental) at 20.

[242] Tr. XXXVI at 7529

- Grid Modernization – The Stipulation provides that the Companies will file a plan within 90 days of the issuance of an order in this proceeding.[243] The plan is subject to Commission approval and provides no concrete benefit to consumers in this proceeding. Indeed, consumers will be charged for the Companies' grid modernization investments and the Companies will receive an 11.28% return on equity on such investment.
- Resource Diversification – The Stipulation contains various other non-committal "resource diversification" proposals.[244] The Companies will "evaluate" investing in battery resources; however, even that evaluation is contingent upon the Commission guaranteeing that the investments will be rate-based for recovery. In addition, the Companies pledge to reactive suspended energy efficiency and demand response programs. However, the Companies have not committed to a level of funding for the program and it must be approved by the Commission before being reactivated.[245] Moreover, the Companies commit only to "strive" to meet 800,000 MWh of energy savings, which potentially could be met through existing programs.[246] Finally, the Companies commit to add 100 MW of wind or solar power, but only "to the extent that Staff deems it helpful" to comply with a future federal or state law or rule. Again, this speculative commitment is made only if the Commission recovery of all costs.[247] The Companies resource

[243] Companies Ex. 154 at 9.
[244] Companies Ex. 154 at 11-12.
[245] Tr. XXXVI at 7531-7534.
[246] Tr. XXXVI at 7535; 7549.
[247] Companies Ex. 154 at 12; Tr. XXXVI at 7541.

diversification commitments are speculative and provide no benefit to consumers in this proceeding during the ESP.

F. The Transition Provision of the Stipulation Does Not Benefit Consumers and is Not in the Public Interest.

Because the proposed ESP IV is for a term of eight years, the Commission is required to review it in year four to determine (1) whether it is still meeting the ESP v. MRO test and will continue to do so throughout ESP IV's term, and (2) whether the prospective effect of continuing the ESP is substantially likely to provide the Companies with excessive returns on equity.[248] Moreover, the signatory parties have agreed that if the Commission were to determine that the ESP IV should be terminated under these tests, Rider RRS and Rider DCR revenues would continue to be collected for the initially approved eight year term.[249]

The most egregious proposal in the Transition Provision is the continuation of Riders RRS and DCR if ESP IV is terminated in year four.[250] As made clear above, consumers are at risk of being charged up to $3.6 billion under Rider RRS, which is one of the primary reasons that NOPEC and other intervenors oppose the Stipulation. In addition, the Companies will receive up to $1.13 billion in DCR revenues for the first four years of ESP IV and up to $2.595 billion over the eight year term of ESP IV, using a return on equity of 10.5 percent from its 2007 rate case.[251] The legislature clearly provided the "four-year check-up" in R.C. 4928.143(E) to protect consumers against future uncertainties, including future electricity prices and equity

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[248] R.C. 4928.143(E).

[249] Companies Ex. 154 (Third Stipulation, Section V.K.) at 18; Tr. XXXVI at 7564-7565.

[250] Indeed, Companies witness Mikkelsen testified that while the Companies would continue to collect Rider RRS and Rider DCR revenues after ESP IV's termination, the Companies would cease providing shareholder funds for economic development and low income assistance under the Stipulation. Tr. XXXIV at 7563-7564.

[251] Companies Ex. 154 (Third Stipulation, Section V.G) at 13; Tr. XXXVI at 7573-7575.

returns. If this feature of the Transition Provision were approved, this statutory protection would be eliminated. This feature of the Transition Provision is unlawful and must be rejected.

In addition, the signatory parties seek to insert language into R.C. 4928.143(E) to bias the results of the tests it requires. Specifically, the signatories seek to compel the Commission to consider quantitative and qualitative factors[252] in conducting the ESP v. MRO test and, among the qualitative factors, consider the "financial health of the utilities."[253] Consideration of the "financial health of the utilities" is not one of the items specifically set for in R.C. 4928.143(B), therefore it may not lawfully be considered as a part of the ESP v. MRO under the Ohio Supreme Court's decision in *CSP II*.

Finally, the Stipulation provides that the ESP may be terminated only if the Commission finds that ***each*** utility has significantly excessive earnings. In other words if two of the three utilities involved in this proceeding are deemed to have significantly excessive earnings, the stipulation would permit them to continue to do so for four more years. This provision clearly is unreasonable, and is also unlawful: R.C. 4928.143(E) requires the Commission to consider the earnings of the individual electric distribution company. The remedy provided if the individual company's earnings are excessive is to terminate the ESP as to that company. Permitting the company to continue to receive substantially excessive earning is unlawful.

The Stipulation's Transition Provision should be summarily rejected.

V. CONCLUSION

For the above reasons, NOPEC respectfully requests that the Third Stipulation and Recommendation be rejected and that the Companies' proposed ESP IV be denied because it fails to meet the ESP v. MRO test. Alternatively, NOPEC requests that ESP IV be modified, at a

[252] As explained above, it is unlawful to consider qualitative factors in the ESP v. MRO test.
[253] Companies Ex. 154 (Third Stipulation, Section V.K.) at 18.

minimum by rejecting Riders RRS, DCR and GDR, such that ESP IV's costs are more favorable than an MRO.

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing Initial Hearing Brief was served *via electronic mail* upon the parties of record this 16th day of February, 2016.

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APPENDIX A

SB 221 as Introduced, Section 4928.14(B)(1)

Legislative Service Commission Bill Analysis, 127th General Assembly, SB 221: As Introduced. SB 221 as Passed in the Senate, Section 4928.14(D)(1).

As Introduced

127th General Assembly
Regular Session
2007-2008

S. B. No. 221

Senator Schuler (By Request)

A BILL

To amend sections 122.41, 122.451, 3706.01, 3706.02, 3706.03, 3706.04, 3706.041, 3706.05, 3706.06, 3706.07, 3706.08, 3706.09, 3706.10, 3706.11, 3706.12, 3706.13, 3706.14, 3706.15, 3706.16, 3706.17, 3706.18, 4905.31, 4905.40, 4928.02, 4928.05, 4928.14, and 4928.17 and to enact sections 1551.41, 4928.111, 4928.141, 4928.142, 4928.64, 4928.68, and 4928.69 of the Revised Code to revise state energy policy to address electric service price regulation, new bonding authority for advanced energy projects, advanced (including renewable) energy portfolio standards, energy efficiency standards, and greenhouse gas emission reporting and carbon control planning requirements.

BE IT ENACTED BY THE GENERAL ASSEMBLY OF THE STATE OF OHIO:

Section 1. That sections 122.41, 122.451, 3706.01, 3706.02, 3706.03, 3706.04, 3706.041, 3706.05, 3706.06, 3706.07, 3706.08, 3706.09, 3706.10, 3706.11, 3706.12, 3706.13, 3706.14, 3706.15, 3706.16, 3706.17, 3706.18, 4905.31, 4905.40, 4928.02, 4928.05, 4928.14, and 4928.17 be amended and sections 1551.41, 4928.111, 4928.141, 4928.142, 4928.64, 4928.68, and 4928.69 of the Revised Code be enacted to read as follows:

infrastructure and generating facilities. The plan shall be filed under an application under section 4909.18 of the Revised Code.

Sec. 4928.14. (A) ~~After its market development period, an~~ An electric distribution utility in this state shall provide consumers, on a comparable and nondiscriminatory basis within its certified territory, a ~~market-based~~ standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service. ~~Such offer shall be filed with the public utilities commission under section 4909.18 of the Revised Code.~~

~~(B) After that market development period, each electric distribution utility also shall offer customers within its certified territory an option to purchase competitive retail electric service the price of which is determined through a competitive bidding process. Prior to January 1, 2004, the commission shall adopt rules concerning the conduct of the competitive bidding process, including the information requirements necessary for customers to choose this option and the requirements to evaluate qualified bidders. The commission may require that the competitive bidding process be reviewed by an independent third party. No generation supplier shall be prohibited from participating in the bidding process, provided that any winning bidder shall be considered a certified supplier for purposes of obligations to customers. At the election of the electric distribution utility, and approval of the commission, the competitive bidding option under this division may be used as the market-based standard offer required by division (A) of this section. The commission may determine at any time that a competitive bidding process is not required, if other means to accomplish generally the same option for customers is readily~~

~~available in the market and a reasonable means for customer participation is developed.~~

~~(C) After the market development period, the~~ The offer is subject to approval or modification and approval by the public utilities commission, following an application that shall be filed with the commission, initially not later than six months after the effective date of the amendment of this section by _____ of the 127th general assembly. The application shall be subject to such filing and procedural requirements as the commission shall prescribe by rule or order. The rules may include transition rules necessary for the initial implementation of this section as so amended.

(B) The standard service offer shall provide for either of the following:

(1) An offer, known as an electric security plan, which shall include the basis of the valuation of the specific generating facilities to be used in providing retail electric generation service and the basis of the cost of rendering generation service using those facilities, as those bases shall be defined by the commission by rule or order. Valuation of facilities under the rule or order shall factor in the extent to which the utility received transition revenues under section 4928.40 of the Revised Code and the extent to which the facilities have been depreciated over time. Further, prices under the plan may include amounts for specified costs, including, but not limited to, either or both of the following:

(a) Environmental compliance costs associated with those facilities as determined by the commission;

(b) Costs incurred by the utility on or after January 1, 2009, in the construction of any generating facility that is located in this state and that, notwithstanding Chapter 4906. of the Revised Code to the contrary, the commission determines and certificates the need for on the basis of resource planning projections developed in accordance with policies and procedures the commission shall prescribe by rule.

(2) An offer, known as a market rate option, under which the utility's standard service offer prices periodically are determined through an open, competitive bidding process.

(C)(1) Nothing in this section precludes a utility for which an application under division (B)(1) of this section has been approved by the commission from later filing an application under division (B)(2) of this section, or vice versa.

(2) If the commission disapproves a standard service offer filed in an initial application under division (B)(2) of this section, the utility shall then immediately file an application under division (B)(1) of this section.

(D)(1) Subject to division (D)(2) of this section, the commission by order may approve or modify and approve the standard service offer contained in any application if it finds both of the following:

(a) The offer and the prices it establishes are just and reasonable and in furtherance of the state policy specified in section 4928.02 of the Revised Code.

(b) The utility is in compliance with section 4928.141 of the Revised Code.

In its order, the commission shall prescribe any requirements for the utility as it considers necessary to implement the state policy and shall provide the term of the offer and a schedule and the procedural and substantive terms and conditions for periodic commission review of the approved offer. In the case of an offer consisting of a market rate option under division (B)(2) of this section, such review shall provide for reconciliation of the standard service offer prices to ensure that they are just and reasonable and in furtherance of the state policy specified in section 4928.02 of the Revised Code.

(2) Regarding a standard service offer consisting of a market rate option under division (B)(2) of this section, the commission shall not approve the offer unless the utility additionally demonstrates all of the following:

(a) The relevant markets are subject to effective competition. For that purpose the commission shall consider the factors prescribed in division (D) of section 4928.06 of the Revised Code.

(b) The utility does not impose unreasonable or discriminatory costs or undue burdens on generation service competition within its generation service territory.

(c) The offer will not impose undue price increases on consumers.

(d) The offer is reasonable on both a short- and long-term basis.

(e) Power purchases supporting the offer are prudent and reasonable.

(3) Regarding any standard service offer consisting of an electric security plan in an application filed by an utility that transferred all or part of its generation facilities to an affiliate of the utility and to the extent authorized by federal law, the commission also may consider power supply or generation service contracts or agreements between the utility and any of its affiliates or between the utility and the holding company owning or controlling the utility.

(E) A utility's initial standard service offer approved under this section as amended by ____ of the 127th general assembly shall take effect on the date the commission shall specify in that order and, on that date, shall supersede any prior authority granted by any law of this state under which the utility provided services described in division (A) of this section to consumers. Nothing in this section precludes commission approval under this section of a standard service offer similar to that in effect under such prior authority.

(F) The failure of a supplier to provide retail electric generation service to customers within the certified territory of the electric distribution utility shall result in the supplier's customers, after reasonable notice, defaulting to the utility's standard service offer filed under division (A) of this section until the customer chooses an alternative supplier. A supplier is deemed under this division to have failed to provide such service if the commission finds, after reasonable notice and opportunity for hearing, that any of the following conditions are met:

(1) The supplier has defaulted on its contracts with customers, is in receivership, or has filed for bankruptcy.

(2) The supplier is no longer capable of providing the service.

(3) The supplier is unable to provide delivery to transmission or distribution facilities for such period of time as may be reasonably specified by commission rule adopted under division (A) of section 4928.06 of the Revised Code.

(4) The supplier's certification has been suspended, conditionally rescinded, or rescinded under division (D) of section 4928.08 of the Revised Code.

(G) Nothing in this section limits an electric distribution utility providing competitive retail electric service to electric load centers within the certified territory of another such utility.

Bill Analysis

Legislative Service Commission

S.B. 221

127th General Assembly
(As Introduced)

Sen. Schuler (By request)

BILL SUMMARY

- Authorizes the Public Utilities Commission (PUCO) to return generally to pre-S.B. 3 (pre-Electric Restructuring Law) regulation of retail electric generation service if that regulation is necessary to implement the statutory state electric services policy.

- Revises and adds to the current objectives of state electric services policy enacted under S.B. 3.

- Prohibits an electric utility selling or transferring any generating facility it owns in whole or in part to any person without prior PUCO approval.

- Retains a standard service offer requirement for electric distribution utilities and newly prescribes the allowable nature of those offers as either an "electric security plan" or a "market rate option."

- Requires an electric security plan to include the basis of the valuation of the generating facilities to be used and the basis of the cost of rendering service using those facilities, as those bases are defined by PUCO rule or order.

- However, requires valuation to factor in a utility's transition revenues under S.B. 3 and facility depreciation; and specifically authorizes the inclusion of environmental compliance costs and the inclusion of construction costs of any new generating facility located in Ohio that the PUCO certificates the need for on the basis of resource planning projections developed in accordance with PUCO rules.

- Requires an electric distribution utility with a PUCO-approved electric security plan to file an energy delivery infrastructure modernization plan or any plan providing for the utility's recovery of costs and a just and reasonable rate of return on such modernization.

- Regarding the bill's market rate option requires open, competitive bidding for generation supply and subjects approval of the option to various criteria in addition to those applicable to an electric security plan.

- Requires the PUCO to adopt rules prescribing advanced energy portfolio standards that will apply to the standard service offers of electric distribution utilities.

- Requires the PUCO to establish energy efficiency standards relating to the projected load growths of electric distribution utilities and authorizes rules providing for revenue decoupling.

- Requires the PUCO to establish carbon control planning requirements for generating facilities and to establish greenhouse gas emission reporting requirements.

- Adds the following to the types of air quality projects that can be funded by the Ohio Air Quality Development Authority (OAQDA) and declares that both qualify as facilities for the control of air and thermal pollution under Section 13, Article VIII, Ohio Constitution: property, devices, or equipment used in the manufacture and production of any equipment that qualifies as an air quality project; and property, devices, or equipment that reduce air contaminant emissions through the generation of electricity using sustainable resources.

- In the manner of its current authority to fund air quality projects, authorizes OAQDA to issue revenue bonds to fund specified types of advanced energy projects and declares that such projects qualify as air and thermal pollution control facilities under the Ohio Constitution.

- Grants OAQDA authority regarding programs to achieve best cost rates for state-owned buildings, facilities, and operations, state-supported colleges and universities, willing local governments, and willing school districts through pooled purchases of electricity and the financing of taxable or tax-exempt prepayment of commodities; and regarding programs to achieve optimal cost electricity for key industrial and energy-intensive sectors.

- Grants OAQDA authority regarding programs to achieve optimal cost financing for new electric generating facilities and regarding the siting, financing, construction, operation, and risk reduction for next-generation base load generating systems, including clean coal facilities with carbon capture or sequestration or advanced nuclear power plants.

- Grants OAQDA authority regarding energy efficiency incentives, sustainable resource energy installations, and research and development regarding sustainable energy.
- Requires the Department of Natural Resources, the Ohio Environmental Protection Agency, and the PUCO jointly by rule to develop an interim policy framework for regulating pilot and demonstration, carbon sequestration activities in Ohio or sequestration products produced in Ohio.
- Requires the PUCO to employ a Federal Energy Advocate to monitor Federal Energy Regulatory Commission and other federal activities and advocate on behalf of Ohio retail electric service consumers.

TABLE OF CONTENTS

CONTENT AND OPERATION

Authority for pre-S.B. 3 regulation

(R.C. 4905.31 and 4928.05(A)(1))

Current law enacted under the Electric Restructuring Law of S.B. 3 of the 123rd General Assembly (primarily, R.C. Chapter 4928.) prohibits municipal regulation of a competitive retail electric service[1] under R.C. Chapter 743., and prohibits the PUCO from regulating such a service under public utility law (R.C. Chapters 4901. to 4909., 4933., 4935., and 4963.) except as provided under the Restructuring Law, and as provided under certain existing statutes and then only to the extent related to service reliability and public safety.

The bill removes current law's prohibition regarding the PUCO and authorizes the PUCO to return to traditional regulation[2] of a competitive retail electric service. To do so, the PUCO must determine that that regulation is necessary to implement statutory electric services policy (see "***State electric services policy***," below, and **COMMENT** 1). As long as the PUCO does not return to traditional regulation, PUCO regulation of generation service apparently will continue as it is under current law except with respect to price regulation (see "***Price regulation***," below).

By way of background, "traditional regulation" addresses those facets of utility operation that affect the provision of utility services, for example, utility stock and bond issuance, mergers and acquisitions, and, of course, service pricing.

Regarding such pricing, the PUCO, under a constant duty to balance the interests of utilities and consumers, determines the amount of revenue a utility needs to cover all its operating costs and earn a rate of return on its overall plant investment. The utility then sets its rates, subject to PUCO approval, so that they will provide it the opportunity to earn that revenue requirement. This "traditional ratemaking" uses a snapshot method of identifying operating costs and plant investment so that, by statute, their calculation is contemporary to the time period for which rates are being determined. In general, any time a utility desires to change its rates because of a change in its cost or investment status, it has to file a base rate case with the PUCO, in which not the specific change, but the utility's entire revenue, expense, cost, and investments are evaluated anew based on contemporary information.

Additional notable aspects of traditional regulation (which also relate to pricing under "***Energy security plan***," below) are that the valuation of utility assets and the determination of a utility's operating costs for rate-making purposes are specified in statute. For instance, under traditional regulation valuation must be done on an original cost basis,[3] for facilities *used and useful* in rendering service, and using books and records maintained by the utility in accordance with a uniform system of accounts specified by the PUCO (R.C. 4905.13, 4909.05(C), and 4909.15(A)). Further, the rate-making process of traditional regulation generally requires the filing of a base rate case application under a statute (R.C. 4909.18) that prescribes certain hearing and other requirements. (This latter aspect of traditional regulation is also relevant to the bills' standard service offer provisions (see "***Approval process***," below).

State electric services policy

(R.C. 4928.02)

The bill revises and adds to the current objectives of the state electric services policy enacted under S.B. 3. Under both current law and the bill, the electric policy applies statewide. The PUCO is required to ensure that the policy is effectuated (R.C. 4928.06(A), not in the bill).

The current policy objectives, which have their genesis in S.B. 3's competitive generation market concept, are as follows: (1) ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service, (2) ensure the availability of unbundled and comparable retail electric service that provides consumers with the supplier, price, terms, conditions, and quality options they elect to meet their respective needs, (3) ensure diversity of electricity supplies and suppliers, by giving consumers effective choices over the selection of those supplies and suppliers and by encouraging the development of distributed and small generation facilities, (4) encourage innovation and market access for cost-effective supply- and demand-side retail electric service, (5) encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems of electric utilities in order to promote effective customer choice of retail electric service, (6) recognize the continuing emergence of competitive electricity markets through the development and implementation of flexible regulatory treatment, (7) ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, (8) ensure retail electric service consumers protection against unreasonable sales practices, market deficiencies, and market power, and (9) facilitate the state's effectiveness in the global economy.

The bill changes these policy objectives by adding five new objectives and modifying three of the current objectives. Specifically, objective (4) above is changed to read: "encourage innovation and market access for *cost-effective retail electric service including, but not limited to, demand-side management, time-differentiated pricing, and implementation of advanced metering infrastructure*."

Objective (5) above is changed to read: "encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems of electric utilities in order to promote *both* effective customer choice of retail electric service *and the development of performance standards and targets for service quality for all consumers, including annual achievement reports written in plain language*."

Objective (8) above is changed to read: "ensure retail electric service consumers *just and reasonable rates and* protection against unreasonable sales practices, market deficiencies, and market power."

The following new objectives are added to the state electric services policy: (1) preclude imbalances in knowledge and expertise among parties in a proceeding under the Restructuring Law to eliminate any appearance of disproportionate influence by any of those parties, (2) ensure that consumers and shareholders share the benefits of, as well as the responsibility for, electric utility investment in facilities supplying retail electric generation service, (3) provide coherent, transparent means of giving appropriate incentives to technologies that can adapt successfully to potential environmental mandates, (4) protect at-risk populations when considering the implementation of any new advanced energy technology, (5) encourage implementation of distributed generation across customer classes through regular review and updating of rules governing critical issues such as, but not limited to, interconnection standards, standby charges, and net metering.

Divestiture policy

(R.C. 4928.17(E))

Current law enacted by S.B. 3 authorizes an electric utility to divest itself of any generating asset without prior PUCO approval. The bill prohibits an electric utility selling or transferring any generating facility it owns in whole or in part to any person without prior PUCO approval. (Prior to S.B. 3, an electric utility, like any other public utility, was subject to policy and a process regarding such prior PUCO approval under R.C. 4905.48 (not in the bill). PUCO approval authority under the bill does not reference that statute.)

Price regulation

(R.C. 4928.14 and 4928.141)

By way of background, S.B. 3 in effect repealed traditional price regulation for electric generation service and declared that the price of generation service would be competitively market-determined starting January 1, 2001. That is, incumbent electric utilities would no longer have state-established exclusive service territories for generation service,[4] and other suppliers of generation services ("electric service companies," meaning generally, power marketers, power brokers, and aggregators) could compete to supply electricity to transmission/distribution customers of the incumbent utilities at each customer's option. Too, the incumbents were free to vie for each other's generation customers.-

Under S.B. 3, beginning generally in 2006 and currently, an electric utility's only regulated duty regarding generation service is to provide a "standard service offer" that assures the constant availability of a firm supply of electricity to (1) any of its distribution customers that have never chosen an alternate generation supplier and (2) customers that did choose but returned, if only briefly, to the utility because their supplier defaulted on its contract.[5] In general, for various reasons, the standard service offers of incumbent utilities over time became, instead of an "essential service fall-back" offer, *the* generation service offer for most of their distribution customers.

Current law enacted under S.B. 3 contemplates that a utility's standard service offer generation price will be "market-based" (not necessarily meaning market-determined) or else will be determined by competitive bidding, but not if the PUCO determines "at any time that a competitive bidding process is not required [because] other means to accomplish generally the same option for customers is readily available in the market and a reasonable means for customer participation is developed."

Since the time S.B. 3's standard service offer requirement took effect, the incumbent utilities have operated under various standard service offers that were developed by settlement among parties and approved by the PUCO as meeting S.B. 3's standard service offer requirement. These standard service offers are typically referred to as "rate stabilization plans." The current rate stabilization plans of the incumbent utilities are scheduled to expire at the end of 2008, except for Dayton Power & Light's, which is scheduled to expire at the end of 2010. Rate stabilization is an utility/PUCO-generated concept described as responding to an assessment that there is no effective competition in the electric generation market. The general nature of the utilities' rate stabilization plans is that they preserve generation prices at existing levels[6] but allow prices to increase in relation to certain costs and under certain circumstances.

The bill retains the standard service offer requirement for electric utilities, but changes the allowable nature of those offers. In that regard, the bill authorizes two types of standard service offers: an "electric security plan" and a "market rate option." It further states that the bill does not preclude PUCO approval of a standard service offer similar to one currently in effect.

Electric security plan. An electric security plan must include the basis of the valuation of the specific generating facilities to be used in providing retail electric generation service and the basis of the cost of rendering generation service using those facilities. The bill provides that the PUCO must define those valuation and cost bases by rule or order. However, the valuation of facilities must factor in the extent to which the utility received transition revenues under S.B. 3[7] (R.C. 4928.40) and the extent to which the facilities have been depreciated over time.

Further, prices under an electric security plan may include amounts for specified costs, including, but not limited to, (1) environmental compliance costs associated with the generating facilities and (2) costs incurred by the utility on or after January 1, 2009, in the construction of any generating facility that is located in Ohio and that, notwithstanding power siting law (Chapter 4906.) to the contrary, the PUCO determines and certificates the need for on the basis of resource planning projections developed in accordance with PUCO-prescribed policies and procedures.

Market rate option. The bill describes the market rate option as an option under which a utility's standard service offer prices periodically are determined through an open, competitive bidding process.

Approval criteria. Standard service offer approval, or modification and approval, requires that the PUCO make both of the following findings: (1) the offer and the prices it establishes are just and reasonable and in furtherance of the state electric service policy described above and (2) the utility is in compliance with the bill's contract filing requirement for the standard service offer proceeding (see "***Approval process***," below).

However, the bill additionally prohibits the PUCO approving a market rate option unless the utility demonstrates that (1) the relevant markets are subject to effective competition, (2) the utility does not impose unreasonable or discriminatory costs or undue burdens on generation service competition within its generation service territory, (3) the offer will not impose undue price increases on consumers, (4) the offer is reasonable on both a short- and long-term basis, and (5) power purchases supporting the offer are prudent and reasonable.

For the purpose of evaluating effective competition in (1) above, the PUCO must consider factors prescribed under S.B. 3, which include, but are not limited to, (1) the number and size of alternative providers of the service, (2) the extent to which the service is available from alternative suppliers in the relevant market, (3) the ability of alternative suppliers to make functionally equivalent or substitute services readily available at competitive prices, terms, and conditions, and (4) other indicators of market power, which may include market share, growth in market share, ease of entry, and the affiliation of suppliers of services (R.C. 4928.06(D)).

Also, regarding any standard service offer consisting of an electric security plan in an application filed by a utility that transferred all or part of its generation facilities to an affiliate, the commission, to the extent authorized by federal law, may consider power supply or generation service contracts or agreements between the utility and its affiliates or between the utility and the holding company owning or controlling the utility.

Approval process. The bill requires a utility to file an application with the PUCO setting forth its standard offer. Initially, such an application must be filed not later than six months after the bill's effective date.

Under the bill, the application is subject to such filing and procedural requirements as the PUCO must prescribe by rule or order. However, in a standard service offer proceeding, an electric distribution utility must file with the PUCO every contract or agreement between the utility or any of its affiliates and a consumer, electric services company, political subdivision, or any party to the proceeding, including any contract or agreement in effect on the filing date of the utility's initial standard service offer application. The bill requires that the details of the contract or agreement be made available as privileged information to intervenors in the proceeding. Additionally, the bill provides that PUCO rules may include transition rules necessary for the initial implementation of the bill's standard service offer requirement.

The bill expressly does not preclude a utility for which an electric security plan application has been approved by the PUCO from later filing an application for a market rate option standard service offer, or vice versa. But, if the PUCO disapproves a market rate option standard service offer filed in a utility's first application under the bill, the utility must then immediately file an application for approval of an electric security plan.

In an order approving a standard service offer, the PUCO must prescribe any requirements for the utility, as it considers necessary to implement the state policy and must provide the term of the offer and a schedule and the procedural and substantive terms and conditions for periodic PUCO review of the approved offer. In the case of an offer consisting of a market rate option, the review must provide for reconciliation of the standard service offer prices to ensure that they are just and reasonable and in furtherance of the state policy.

Approval effect. Regarding a utility's approved, initial standard service offer, the bill specifies that the offer takes effect on the date the PUCO specifies in its order. The bill further states that, on that specified date, the offer supersedes any prior authority granted by Ohio law under which the utility provided generation service.

Additionally, the bill states that nothing in its standard service offer provisions limits an electric distribution utility providing competitive retail electric (generation) service to electric load centers[8] within the certified territory of another such utility.

Advance energy portfolio standards

(R.C. 4928.142)

The bill requires the PUCO to adopt rules prescribing advanced energy portfolio standards that will apply to the standard service offers of electric utilities. In adopting the rules, the PUCO must consider available technology, costs, job creation, and economic impacts. The rules must require evaluation of and encourage, where necessary, development and implementation of next-generation energy technologies, including, but not limited to, renewable energy sources, clean coal technology, advanced nuclear generation, fuel cells, and cogeneration.

The bill requires that the rules seek to achieve specified interim goals such that, by 2025, advanced energy technologies must provide 25% of a utility's standard service offer. At least half of the advanced energy the utility implements must be generated from renewable energy sources. The renewable sources must include solar power, with any remainder supplied by, but not limited to, any clean coal technology with carbon controls, an advanced nuclear plant, or a cogeneration project, the original construction of which is initiated after January 1, 2009. Additionally, at least half of the advanced energy implemented must be met through facilities located in Ohio.

Electric system modernization

(R.C. 4928.111)

The bill requires an electric utility with a PUCO-approved electric security plan to file with the PUCO a "long-term energy delivery infrastructure modernization plan or any plan providing for the utility's recovery of costs and a just and reasonable rate of return on such infrastructure modernization." The plan must specify the initiatives the utility must take to improve electric service reliability by rebuilding, upgrading, or replacing utility infrastructure *and* generating facilities. The plan must be filed in an application under the traditional ratemaking law (R.C. 4909.18) and therefore subject to any applicable hearing and other requirements of that law.

Energy efficiency standards

(R.C. 4928.64)

The bill requires the PUCO to establish by rule energy efficiency standards applicable to electric distribution utilities. Under the rules, a utility must implement energy efficiency measures that will result in not less than 25% of projected growth in its electric load and not less than 10% of its total peak demand being achieved, by 2025, through those measures. The rules must include a requirement that an electric distribution utility provide a customer upon request with three years of consumption data in an accessible form. Additionally, the rules may provide for "decoupling." (Although not further described in the bill, this term usually refers to a policy that detaches utility earnings from amount of commodity sold.)

Greenhouse gas emissions, carbon control

(R.C. 4928.69)

The bill requires the PUCO to adopt rules establishing greenhouse gas[9] emission reporting requirements (presumably applicable only to public utilities regulated by the PUCO). The rules must include participation in the Climate Registry. The Registry's web site describes the Registry as "a collaboration between states, provinces, and tribes aimed at developing and managing a common greenhouse gas emissions reporting system with high integrity that is capable of supporting various greenhouse gas emissions reporting and reduction policies for its member states and tribes and reporting entities."[10]

The bill also requires the PUCO to adopt rules establishing carbon control planning requirements for each electric generating facility located in Ohio that emits greenhouse gases, including facilities in operation on the bill's effective date.

Carbon sequestration

(R.C. 1551.41)

The bill requires the Department of Natural Resources, the Ohio Environmental Protection Agency, and the PUCO, jointly by rule, to develop an interim policy framework for supervision and regulation by the agencies of pilot and demonstration, carbon sequestration activities located in Ohio and sequestration products produced in Ohio.

State revenue bonds

(R.C. 122.41, 122.451, 3706.01 through 3706.18, and 4905.40)

Current law authorizes the Ohio Air Quality Development Authority (OAQDA) to issue revenue bonds and notes, the proceeds of which can be used to fund the cost[11] of air quality projects. Funding can come in the form of an OAQDA loan or grant or can otherwise be paid from bond proceeds.

The bill adds to the types of air quality projects that can be funded by the OAQDA. It also gives OAQDA new, identical, statutory authority to issue revenue bonds to fund advanced energy projects (see **COMMENT** 2). The latter also involves extending to advanced energy projects two existing statutory provisions relating to a Department of Development mortgage insurance program for air quality, wastewater, or solid wastes projects.

Air quality projects

Current law declares that "air quality projects" qualify as facilities for the control of air pollution and thermal pollution related to air under Section 13, Article VIII, Ohio Constitution (R.C. 3706.01(G); see also R.C. 3706.03(A)). That constitutional provision empowers state government to lend the state's aid and credit to private entities (by issuing of debt backed by revenues other than tax revenues) for the express purposes of controlling air, water, and thermal pollution or disposing of solid waste. The constitutional provision also states that,

> except for facilities for pollution control or solid waste disposal, as determined by law, no guarantees or loans and no lending of aid or credit shall be made [by statute] for facilities to be constructed for the purpose of providing electric or gas utility service to the public.

The relationship between the constitutional provision and statute is that statute, subject to the limitations of the constitutional provision, designates OAQDA to implement the constitutional provision by funding air quality (air or thermal pollution) projects.

Under current statute, projects eligible for OAQDA funding are, in brief: (1) methods, or modifications or replacements of property, processes, devices, structures, or equipment, directed at air contaminants,[12] (2) property used for collecting, storing, treating, using, processing, or disposing of a by-product or solid waste resulting from a project described in (1), (3) motor vehicle inspection stations and station equipment, (4) ethanol or other biofuel facilities and facility equipment, (5) property, devices, or equipment that reduce emissions of air contaminants through improvements in energy efficiency or energy conservation, (6) research and development projects under the Ohio Coal Development Office, (7) property used for collecting, storing, treating, using, processing or disposing of a by-product or solid waste resulting from a project described in (6) or from the use of clean coal technology, excluding property used primarily for other subsequent commercial purposes, (8) property that is part of the FutureGen project[13] or related to its siting, and (9) property or any system to be used for any of the purposes described in (1) to (8), whether another purpose is also served, and any property or system incidental to or that has to do with, or the end purpose of which is, any of (1) to (8) above.

The bill makes the following eligible as air quality projects and expands (9) above to include these new types of projects: (1) property, devices, or equipment necessary for the manufacture and production of any equipment that qualifies as an air quality project, and (2) property, devices, or equipment that reduce air contaminant emissions through the generation of electricity using sustainable resources. "Sustainable resources" include, but are not limited to, solar, wind, tidal or wave, biomass, biofuel, hydro, or geothermal resources. The bill declares that both of these new types of air quality projects qualify as facilities for the control of air pollution and thermal pollution related to air under Section 13, Article VIII, Ohio Constitution (R.C. 3706.01(G)).

Advanced energy projects

Under the bill, OAQDA's authority to fund advanced energy projects is the same as its authority to fund air quality projects. "Advanced energy projects" consist of methods or of modifications or replacements of property, processes, devices, structures, or equipment, regarding any of the following: (1) a coal-based generating facility that can control or prevent carbon dioxide emissions by at least 80% (compared to the emissions that would occur without its clean coal technology), (2) for advanced nuclear energy production, generation III technology as defined by the Nuclear Regulatory Commission, other later technology, or "significant improvements to existing facilities," (3) electric generating fuel cells including, but not limited to, proton exchange membrane fuel cells, phosphoric acid fuel cells, molten carbonate fuel cells, or solid fuel cells, and (4) cogeneration technology using a heat engine or power station to generate electricity and useful heat simultaneously. An advanced energy project also includes any property or system to be used in whole or in part for (1) to (4) above, whether another purpose also is served, and any property or system incidental to or that has to do with, or the end purpose of which is, any of (1) to (4).

The bill declares that advanced energy projects for industry, commerce, distribution, or research, including public utility companies, qualify as facilities for the control of air pollution and thermal pollution related to air under Section 13, Article VIII, Ohio Constitution (R.C. 3706.03(A)).

Additional OAQDA authority

(R.C. 3706.04)

Current law lists a number of general powers of the OAQDA with respect to air quality projects, including, for example, adopting an official OAQDA seal, making loans and grants, acquiring or constructing property, engaging in certain competitive bidding, and receiving federal funds. The bill extends those same powers with respect to advanced energy projects funded by OAQDA.

Further, the bill establishes additional OAQDA authority (although the bill is not clear regarding how these new powers relate, if at all, to OAQDA bonds or bond proceeds). The bill authorizes OAQDA to develop, encourage, promote, support, and implement programs to achieve best cost rates for state-owned buildings, facilities, and operations, state-supported colleges and universities, willing local governments, and willing school districts through pooled purchases of electricity and the financing of taxable or tax-exempt prepayment of commodities. OAQDA additionally may develop, encourage, promote, support, and implement programs to achieve optimal cost electricity available to key industrial and energy-intensive sectors of Ohio's economy.

The bill also empowers OAQDA to develop, encourage, promote, support, and implement programs to achieve optimal cost financing for electric generating facilities to be constructed on or after January 1, 2009. And, it empowers OAQDA to lead, encourage, promote, and support siting,[14] financing, construction, and operation for, and reduce the costs of associated risks of, early implementations of next-generation base load generating systems, including clean coal generating facilities with carbon capture or sequestration or advanced nuclear power plants.

Additional authority is granted for OAQDA to develop, encourage, and provide incentives for investments in energy efficiency; develop, encourage, promote, and support implementation in Ohio of sustainable resource energy installations; and engage in and coordinate state-supported energy research and development with respect to reliable, affordable, and sustainable energy in Ohio.

Federal energy advocate; RTO participation

(R.C. 4928.68)

The bill requires the PUCO to employ a Federal Energy Advocate to monitor the activities of the Federal Energy Regulatory Commission (FERC) and other federal agencies and advocate on behalf of the interests of Ohio retail electric service consumers. The attorney general must represent the Advocate before the FERC and other federal agencies. Among other duties assigned by the PUCO, the Advocate must examine the value of the participation of Ohio electric utilities in regional transmission organizations and submit a report to the PUCO on whether continued participation of those utilities is in the interest of retail electric consumers.

COMMENT

1. The bill authorizes the PUCO to return to traditional regulation of a competitive retail electric service if necessary to implement state electric services policy. The bill could be clarified regarding what that authority means with respect to current law that appears to continue under the bill notwithstanding a return to traditional regulation and, specifically, whether the bill intends that the generation prices of electric utilities be regulated but those charged by other suppliers not be regulated. The bill also is not clear as to whether the authority to return to traditional regulation also includes PUCO authority to revert back to current regulation as amended by the bill.

2. In keeping with the apparent intent of the bill, the definition of "revenues" in R.C. 3706.01 should be amended to add appropriate references to advance energy projects.

HISTORY

ACTION	DATE
Introduced	09-25-07

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[1] For the purpose of this analysis, "competitive retail electric service" means electric generation service. By statutory declaration in current R.C. 4928.03, electric generation service is a competitive retail electric service. So are services provided by alternative generation suppliers: power marketing, power brokering, and customer aggregation. Current law (R.C. 4928.04) gives the PUCO authority to declare ancillary services, metering, and billing and collection services competitive services as well, but the PUCO has not exercised that authority, so those services remain noncompetitive services under the Restructuring Law. The bill does not amend or repeal any of these current law designations or authority. It also makes no changes in another major area of Electric Restructuring Law--tax policy applicable to electric utilities and electric services.

[2] A return to traditional regulation does not mean a return to pre-S.B. 3 regulation entirely, since S.B. 3 repealed certain provisions of traditional regulation, such as provisions authorizing an electric fuel component in rates and provisions addressing environmental compliance facilities of electric utilities, and amended other provisions.

[3] As opposed to some other basis, for example, original cost less depreciation or replacement cost new.

[4] Although such exclusive territories continued as to other components of electric service, such as distribution (R.C. 4933.81 et seq.).

[5] More fully, a customer can return under current law to (the standard service offer of) its incumbent utility if the customer's supplier (1) has defaulted on its contract, (2) is in receivership, (3) has filed for bankruptcy, (4) is no longer capable of providing the service, (5) is unable to provide delivery to transmission or distribution facilities for such reasonable period of time as the PUCO may specify by rule, or (6) has had its PUCO certification suspended, conditionally rescinded, or rescinded (R.C. 4928.14(F)).

[6] Generally meaning, at the level of the utility's pre-2000 price of electricity, determined through an unbundling process, which required the price of generation to be what remained after all other electric service components were removed from the bundled price for electric service that reflected the vertical integration of Ohio electric utilities pre-S.B. 3. Those bundled prices had not changed since the utilities' last rate cases, which generally were in the late 1980s and early 1990s.

[7] "Transition revenues" refers to a source of revenue available to incumbent utilities, by application to the PUCO, for generation costs "unrecoverable in a competitive market" (R.C. 4928.40). Senate Bill 3 required the application to be in the form of a requisite transition plan that covered a number of issues relevant to utilities' monopoly position as providers of electric services and to their evolution to a competitive generation market. In actuality, transition plans consisted of negotiated settlements submitted for PUCO approval.

[8] Basically, an electric load center is the metered point of electricity delivery (R.C. 4928.01(A)(8) and 4933.81(E)).

[9] "[G]reenhouse gases allow sunlight to enter the atmosphere freely. When sunlight strikes the Earth's surface, some of it is reflected back towards space as infrared radiation (heat). Greenhouse gases absorb this infrared radiation and trap the heat in the atmosphere. ...Some of [the gases] occur in nature (water vapor, carbon dioxide, methane, and nitrous oxide), while others are exclusively human-made (like gases used for aerosols)....During the past 20 years, about three-quarters of human-made carbon dioxide emissions were from burning fossil fuels." From the U.S. Energy Information Administration, at < http://www.eia.doe.gov/oiaf/1605/ggccebro/chapter1.html>.

[10] <http://www.theclimateregistry.org/>. According to the web site, as of August 9, 2007, Ohio is listed having jointed the Registry, along with all other states except Alaska, Texas, Louisiana, Mississippi, Arkansas, North Dakota, South Dakota, Nebraska, Kentucky, Indiana, and West Virginia. The Ohio contact listed on the site is the Director of Ohio EPA. The state's listing currently enables a utility's voluntary participation in the Registry.

[11] "Cost" means the cost of acquisition and construction, the cost of acquisition of all land, rights-of-way, property rights, easements, franchise rights, and interests required for such acquisition and construction, the cost of demolishing or removing any buildings or structures on land so acquired, including the cost of acquiring any lands to which such buildings or structures may be moved, the cost of acquiring or constructing and equipping a principal OAQDA office and sub-offices, the cost of diverting highways, interchange of highways, and access roads to private property, including the cost of land or easements for such access roads, the cost of public utility and common carrier relocation or duplication, the cost of all machinery, furnishings, and equipment, financing charges, interest prior to and during construction and for no more than 18 months after completion of construction, engineering, expenses of research and development, the cost of any commodity contract, including related fees and expenses, legal expenses, plans, specifications, surveys, studies, cost and revenue estimates, working capital, other expenses necessary or incident to determining the feasibility or practicability of acquiring or constructing a project, administrative expense, and such other expense as may be necessary or incident to the acquisition or construction of the project, the financing of such acquisition or construction, including the amount authorized in the OAQDA bond resolution, the financing of the placing of such project in operation, and any obligation, cost, or expense incurred by any governmental agency or person for surveys, borings, preparation of plans and specifications, and other engineering services, or any other cost described above (R.C. 3706.01 (I)).

[12] That is, methods, modifications, or replacements that remove, reduce, prevent, contain, alter, convey, store, disperse, or dispose of particulate matter, dust, fumes, gas, mist, smoke, noise, vapor, heat, radioactivity, radiation, or odorous substances, or substances containing those contaminants, or that render them less noxious or reduce their concentration in the air (R.C. 3706.01(C) and (G)).

[13] This project is a coal-fueled, zero-emissions power plant designed to prove the feasibility of producing electricity and hydrogen from coal and nearly eliminating carbon dioxide emissions through capture and permanent storage. The future site of the project has been narrowed by the U.S. Department of Energy to Texas or Illinois.

[14] This apparently intends that OAQDA lead, encourage, promote, and support siting of such facilities before the Power Siting Board, if the facilities qualify as major utility facilities under power siting law.

APPENDIX B

SB 221 as Passed in the Senate, Section 4928.14(D)(1)

Legislative Service Commission Bill Analysis, 127th General Assembly, SB 221: As Passed by the Senate.

As Passed by the Senate

127th General Assembly
Regular Session
2007-2008

Sub. S. B. No. 221

Senators Schuler (By Request), Jacobson, Harris, Fedor, Boccieri, Miller, R., Morano, Mumper, Niehaus, Padgett, Roberts, Wilson, Spada

—

A BILL

To amend sections 122.41, 122.451, 3706.01, 3706.02, 3706.03, 3706.04, 3706.041, 3706.05, 3706.06, 3706.07, 3706.08, 3706.09, 3706.10, 3706.11, 3706.12, 3706.13, 3706.14, 3706.15, 3706.16, 3706.17, 3706.18, 4905.31, 4905.40, 4909.161, 4928.01, 4928.02, 4928.05, 4928.06, 4928.12, 4928.14, 4928.15, 4928.16, 4928.17, 4928.18, 4928.20, and 4928.21, to enact sections 1551.41, 4928.111, 4928.141, 4928.142, 4928.64, 4928.68, and 4928.69, and to repeal sections 4928.31, 4928.32, 4928.33, 4928.34, 4928.35, 4928.36, 4928.37, 4928.38, 4928.39, 4928.40, 4928.41, 4928.42, 4928.431, and 4928.44 of the Revised Code to revise state energy policy to address electric service price regulation and to provide for new bonding authority for advanced energy projects, advanced (including sustainable resource) energy portfolio standards, energy efficiency standards, and greenhouse gas emission reporting and carbon control planning requirements.

BE IT ENACTED BY THE GENERAL ASSEMBLY OF THE STATE OF OHIO:

holding of those investigations or hearings, or in the making of those orders, the commission is functioning under agreements or compacts between states, under the concurrent power of states to regulate interstate commerce, as an agency of the United States, or otherwise.

(2) The commission shall negotiate and enter into agreements or compacts with agencies of other states for cooperative regulatory efforts and for the enforcement of the respective state laws regarding the transmission entity.

(E) If a qualifying transmission entity is not operational as contemplated in division (A) of this section, division (A)(13) of section 4928.34 of the Revised Code, or division (G) of section 4928.35 of the Revised Code, the commission by rule or order shall take such measures or impose such requirements on all for-profit entities that own or control electric transmission facilities located in this state as the commission determines necessary and proper to achieve independent, nondiscriminatory operation of, and separate ownership and control of, such electric transmission facilities on or after the starting date of competitive retail electric service.

Sec. 4928.14. (A) After its market development period, an An electric distribution utility in this state shall provide consumers, on a comparable and nondiscriminatory basis within its certified territory, a market based standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service. Such offer shall be filed with the public utilities commission under section 4909.18 of the Revised Code.

(B) After that market development period, each electric distribution utility also shall offer customers within its certified territory an option to purchase competitive retail electric service the price of which is determined through a competitive bidding process. Prior to January 1, 2004, the commission shall adopt rules concerning the conduct of the competitive bidding process, including the information requirements necessary for customers to choose this option and the requirements to evaluate qualified bidders. The commission may require that the competitive bidding process be reviewed by an independent third party. No generation supplier shall be prohibited from participating in the bidding process, provided that any winning bidder shall be considered a certified supplier for purposes of obligations to customers. At the election of the electric distribution utility, and approval of the commission, the competitive bidding option under this division may be used as the market based standard offer requiredby division (A) of this section. The commission may determine at any time that a competitive bidding process is not required, if other means to accomplish generally the same option for customers is readily available in the market and a reasonable means for customer participation is developed.

(C) After the market development period, the (B) Beginning the first day of January of the calendar year that follows the scheduled expiration of an electric distribution utility's rate plan, the standard service offer of the utility, for the purpose of compliance with division (A) of this section, shall consist of all of the following:

(1) As to each customer class, the total charges to customers under that rate plan that are in effect, as filed with the commission, on the first day of February of that year of expiration, exclusive of any charges for transmission and distribution services;

(2) As to each customer class, any adjustments for costs that

are incurred by the utility, the recovery of which are pursuant to an application authorized by the commission under the rate plan, and that go into effect on or after that first day of February and before that first day of January;

(3) As to each customer class, any adjustments for deferred costs authorized by commission order, to the extent not included under divisions (B)(1) and (2) of this section;

(4) As to the specific customer, any price applicable to that customer that was approved by commission order under section 4905.31 of the Revised Code issued prior to October 28, 2007, exclusive of the transmission and distribution service components of that price. As used in divisions (B) and (D)(2)(a) of this section, "rate plan" means the standard service offer order in effect on the effective date of the amendment of this section by S.B. 221 of the 127th general assembly.

(C) For the purpose of complying with division (A) of this section, beginning on the effective date of the amendment of this section by S.B. 221 of the 127th general assembly and pursuant to filing requirements the commission shall prescribe by rule, a utility may file an application for commission approval of a modified standard service offer. Upon that filing, the commission shall set the date and time for hearing, send written notice of the hearing to the utility, and publish notice of the hearing one time in a newspaper of general circulation in each county in the service area affected by the application.

(D)(1) Subject to division (D) of this section, a standard service offer proposed under division (C) of this section, and herein designated an electric security plan, shall adjust a utility's standard service offer relative to changes in one or more costs incurred by the utility to serve jurisdictional load in this state and specified in the application. An adjustment for a change in a capitalized cost shall also include a just and reasonable return on that cost. The amount of any adjustment under division (D) of this section shall be offset by any decrease in costs, excluding reductions in amoritization relating to costs recovered through a regulatory transition charge authorized by the commission as of February 1, 2008, and by any change in kilowatt-hours sold that are associated with serving jurisdictional load in this state. Costs, as determined by the commission, may include, but are not limited to, any of the following:

(a) Environmental compliance costs for one or more specified generating facilities, as determined by the commission, except those included under division (D)(1)(c) of this section;

(b) The cost of fuel for one or more specified generating facilities or of purchased power;

(c) The cost of construction of one or more new, specified generating facilities that, superseding Chapter 4906. of the Revised Code, the commission determines and certificates the need for as to the standard service offer on the basis of resource planning projections developed in accordance with policies and procedures the commission shall prescribe by rule; or the cost, in excess of two hundred fifty million dollars, of construction of an environmental retrofit to a specified, then-existing generating facility. A price adjustment for such a new facility or environmental retrofit shall be consistent with section 4909.15 of the Revised Code and consistent with section 4909.18 of the Revised Code as applicable; and, subject to such terms and conditions as the commission prescribes in an order issued under division (D)(6) of this section, shall be for the actual life of the facility.

(d) Operating, maintenance, and other costs, including taxes;

(e) Costs of investment in one or more specified generating reasonable return on that cost. The amount of any adjustment under division (D) of this section shall be offset by any decrease in costs, excluding reductions in amoritization relating to costs recovered through a regulatory transition charge authorized by the commission as of February 1, 2008, and by any change in kilowatt-hours sold that are associated with serving jurisdictional load in this state. Costs, as determined by the commission, may include, but are not limited to, any of the following:

(a) Environmental compliance costs for one or more specified generating facilities, as determined by the commission, except those included under division (D)(1)(c) of this section;

(b) The cost of fuel for one or more specified generating facilities or of purchased power;

(c) The cost of construction of one or more new, specified generating facilities that, superseding Chapter 4906. of the Revised Code, the commission determines and certificates the need for as to the standard service offer on the basis of resource planning projections developed in accordance with policies and procedures the commission shall prescribe by rule; or the cost, in excess of two hundred fifty million dollars, of construction of an environmental retrofit to a specified, then-existing generating facility. A price adjustment for such a new facility or environmental retrofit shall be consistent with section 4909.15 of the Revised Code and consistent with section 4909.18 of the Revised Code as applicable; and, subject to such terms and conditions as the commission prescribes in an order issued under division (D)(6) of this section, shall be for the actual life of the facility.

(d) Operating, maintenance, and other costs, including taxes;

(e) Costs of investment in one or more specified generating facilities;

(f) Costs of providing standby and default service pursuant to divisions (A) and (H) of this section.

However, costs under division (D) of this section shall exclude forfeitures, administrative or civil penalties, fines, court costs, and attorney's fees associated with violations of or noncompliances with federal or any state's environmental laws or with facilities' permits.

A standard service offer that includes costs under division (D)(1)(a), (b), (d), (e), or (f) of this section may provide for automatic increases or decreases in the standard service offer price, but, in the case of a cost under division (D)(1)(d) of this section, only if the cost was outside of the utility's control or responsibility.

In the case of an advanced energy technology or facility under section 4928.142 of the Revised Code, the costs of which are included in a standard service offer as authorized under this division, the portion of the standard service offer price attributable to those costs shall be bypassable by a consumer that has exercised choice of supplier under section 4928.03 of the Revised Code, but bypassable only to the extent the commission determines that the advanced energy technology or facilities implemented by that supplier are comparable to that implemented by the utility, under section 4928.142 of the Revised Code as of the issuance of an order under division (D)(6) of this section, for the purpose of the utility's compliance with division (A) of section 4928.142 of the Revised Code.

(2)(a) For the purpose of a utility's initial application under division (D)(1) of this section, the adjustment for a particular cost shall be determined using a baseline measure of that cost as of the first day of February of the calendar year in which the utility's rate plan is scheduled to expire.

(b) If a utility continues to provide its standard service offer pursuant to an electric security plan, for any later such application by the utility, the baseline measure shall be the cost, and the associated kilowatt-hours sold, as determined under the utility's then-existing approved plan. With regard to a generating facility under division (D)(1)(c) of this section, associated decreases in cost and changes in kilowatt-hours sold shall include, but are not limited to, retirement of all or part of any other generating facility, the cost of which had been included in the utility's rate base prior to the effective date of the amendment of this section by Sub. S.B. 221 of the 127th general assembly or was included under division (D)(1)(c) or (e) of this section.

(3) A standard service offer under division (D)(1) of this section may specify the standard, factors, or methodology that the commission shall use for the purpose of division (E)(2)(c) of this section and within such timeframe as the commission specifies in its order under division (D)(6) of this section, if the utility later files an application pursuant to division (E) of this section.

(4) Regarding an application filed under division (D)(1) of this section by a utility that transferred all or part of its generating facilities to an affiliate of the utility and to the extent authorized by federal law, the commission may consider purchased power or other contracts or agreements between the utility and any of its affiliates or between the utility and the holding company owning or controlling the utility.

(5) For the purpose of division (D) of this section, if the utility has entered into a contract or agreement with an affiliate for the provision of a competitive retail electric service, the commission shall treat as a cost of the utility under the

security plan the affiliate's costs of providing that service.

(6) The burden of proof under division (D)(6) of this section shall be on the utility. The commission by order may approve or modify and approve a standard service offer under division (D)(1) of this section if it finds both of the following:

(a) The offer and the prices it establishes are just and reasonable as to each customer class and are consistent with the policy specified in section 4928.02 of the Revised Code.

(b) The utility is in compliance with section 4928.141 of the Revised Code. In its order, the commission shall prescribe such requirements for the utility as the commission considers necessary for the utility to implement applicable objectives of the policy specified in section 4928.02 of the Revised Code. The order also may provide a schedule and the procedural and substantive terms and conditions for periodic commission review of the approved offer.

(E)(1) As authorized under this division, a standard service offer proposed under division (C) of this section, and herein designated a market rate option, shall require that the utility's standard service offer price be determined periodically through an open, competitive bidding process. Prior to the approval of such an offer under division (E)(2) of this section, the utility shall conduct such competitive bidding for the purpose of establishing the original price under the offer.

(2) The burden of proof under division (E)(2) of this section shall be on the utility. The commission by order shall approve or modify and approve the standard service offer under division (E)(1) of this section if the commission determines all of the following are met:

(a) The offer and the prices it establishes are just and reasonable as to each customer class and are consistent with the policy specified in section 4928.02 of the Revised Code.

(b) The utility is in compliance with section 4928.141 of the Revised Code.

(c) With respect to generation service, the relevant markets are subject to effective competition. For that purpose and except as otherwise provided under division (D)(3) of this section, the commission shall consider the factors prescribed in division (D) of section 4928.06 of the Revised Code and such other or additional factors as the commission may prescribe by rule. The commission shall prescribe by rule the methodology it will use to evaluate whether the effective competition standard under division (E)(2)(c) of this section is met.

(d) The standard service offer price for a customer class as determined under competitive bidding under division (E)(1) of this section is more favorable than, or at least comparable to, its price-to-compare for that class. That price-to-compare shall be the price that the commission shall determine for the comparable time period and in the manner of an electric security plan under division (D) of this section.

In its order, the commission shall prescribe such requirements for the utility as it considers necessary for the utility to implement applicable objectives of the policy specified in section 4928.02 of the Revised Code. The order also may provide the procedural and substantive terms and conditions for periodic commission review of the approved offer. That review shall provide for the reconciliation of the standard service offer price to ensure that the price is just and reasonable as to each customer class and consistent with the policy specified in section 4928.02 of the Revised Code.

(F) A utility's standard service offer approved under this section shall take effect on the date the commission shall specify in the approval order and, on that date, the newly approved offer shall supersede the prior standard service offer of the utility.

(G)(1) Nothing in this section precludes a utility for which a standard service offer under division (D) of this section has been approved by the commission in accordance with this section from later filing an application under division (E) of this section, or vice versa.

(2) The commission has no authority to require a utility, for which it has ever approved a market rate option standard service offer under division (E) of this section, to file an application under division (D) of this section.

(H) The failure of a supplier to provide retail electric generation service to customers within the certified territory of the electric distribution utility shall result in the supplier's customers, after reasonable notice, defaulting to the utility's standard service offer filed under division (A) of this section until the customer chooses an alternative supplier. A supplier is deemed under this division to have failed to provide such service if the commission finds, after reasonable notice and opportunity for hearing, that any of the following conditions are met:

(1) The supplier has defaulted on its contracts with customers, is in receivership, or has filed for bankruptcy.

(2) The supplier is no longer capable of providing the service.

(3) The supplier is unable to provide delivery to transmission or distribution facilities for such period of time as may be reasonably specified by commission rule adopted under division (A) of section 4928.06 of the Revised Code.

(4) The supplier's certification has been suspended, conditionally rescinded, or rescinded under division (D) of section 4928.08 of the Revised Code.

(I) Nothing in this section limits an electric distribution utility providing competitive retail electric service to electric load centers within the certified territory of another such utility.

Sec. 4928.141. During a proceeding under section 4928.14 of the Revised Code and upon submission of an appropriate discovery request, an electric distribution utility shall make available to the requesting party every contract or agreement that is between the utility or any of its affiliates and a party to the proceeding, consumer, electric services company, or political subdivision and that is relevant to the proceeding, subject to such protection for proprietary or confidential information as is determined appropriate by the public utilities commission.

Sec. 4928.142. (A) Subject to division (B) of this section, an electric distribution utility by the end of 2025 shall provide a portion of the electricity supply required for its standard service offer under section 4928.14 of the Revised Code from advanced energy. That portion shall equal twenty-five per cent of the total number of kilowatt-hours of electricity supplied by the utility to any and all electric consumers whose electric load centers are located within the utility's certified territory. However, subject to division (B) of this section, nothing in this section precludes a utility from providing a greater percentage. The advanced energy supply shall be consistent with the following requirements:

(1) At least half of the advanced energy implemented by the utility by the end of 2025 shall be generated from sustainable resources as defined in section 3706.01 of the Revised Code and shall include solar power. The remainder shall be supplied from advanced energy facilities as defined in divisions (X)(1) to (4) of section 3706.01 of the Revised Code.

Bill Analysis

Legislative Service Commission

Sub. S.B. 221

127th General Assembly
(As Passed by the Senate)

Sens. Schuler (By request), Jacobson, Harris, Fedor, Boccieri, R. Miller, Morano, Mumper, Niehaus, Padgett, Roberts, Wilson, Spada

BILL SUMMARY

- Focuses on two main subject areas: electricity prices and electricity sources.

On pricing:

- Preserves the right of customer choice enacted by S.B. 3 of the 123rd General Assembly; as to generation service, generally extends the life of the utilities' current rate plans beyond their scheduled expiration; and allows future, cost-related adjustments to generation prices.

- Also grants the Public Utilities Commission (PUCO) the authority to regulate electric utilities under the traditional regulatory approach that applied to them before S.B. 3.

- Revises and adds to the current objectives of state electric services policy enacted under S.B. 3.

- Retains the general standard service offer (SSO) requirement for electric distribution utilities.

- Declares that, as of January 1, 2009 (2011 for Dayton Power & Light), a utility's SSO price:

  --As to each customer with a (bilateral or other) contract with a utility approved by the PUCO before October 28, 2007, will consist of that contract price, exclusive of its transmission and distribution service components;

  --As to each of its customer classes, will consist of the total charges--exclusive of charges for transmission and distribution services--that are payable by customers on February 1, 2008 (2010 for DP&L) under the utility's current SSO rate plan and, further, is subject to (1) any price adjustments for costs incurred by the utility and authorized under its existing rate plan for implementation on or after that February 1, but before the following January 1, and (2) to the extent they are not included in those total charges or price adjustments, any price adjustments for deferred costs authorized by PUCO order.

- Authorizes a distribution utility to apply for a modified SSO consisting of either an "electric security plan" (ESP) or a "market rate option" (MRO).

- Provides that, under an ESP, a utility's SSO price can change relative to changes in the baseline measure of any one or more costs incurred by it to serve jurisdictional load in Ohio, excluding certain costs related to environmental law violations.

- Allows an ESP to provide for automatic SSO price adjustments for certain enumerated costs and requires consistency with traditional rate-making law if the costs concern construction of a new generating facility or major environmental retrofit.

- Requires that any adjustment for a particular cost in a utility's ESP application be determined using a baseline measure of cost.

- Requires that, other than in a utility's initial application, that baseline must be the cost, and the associated kilowatt-hours sold, as determined under the utility's then-existing approved plan and that, regarding a new generating facility or major environmental retrofit, associated decreases in cost and changes in kilowatt-hours sold must include any retirement of all or part of any other generating facility, the cost of which had been included in the utility's rate base prior to the bill's effective date or was included in a prior ESP.

- Authorizes the PUCO to specify in an ESP any alternate standard, factors, or methodology that it must use, within a timeframe the PUCO specifies, to approve a MRO for the utility if it later files an application for that approval.

- Requires open, competitive bidding for generation supply under a MRO.

- Prohibits an electric utility selling or transferring any generating facility it owns in whole or in part to any person without prior PUCO approval.

- Requires an electric distribution utility with a PUCO-approved ESP to file an energy delivery infrastructure modernization plan or any plan providing for the utility's recovery of costs and a just and reasonable rate of return on such modernization.

- Adds to current law regarding line extensions a provision requiring the PUCO to consider rules regarding distribution costs, including line extensions, in carrying out the state electric policy.

- Requires the PUCO to employ a Federal Energy Advocate and requires the Advocate to examine the value of the participation of Ohio electric utilities in regional transmission organizations and submit a report to the PUCO.

- Requires that the Advocate monitor Federal Energy Regulatory Commission and other federal agencies and advocate on behalf of Ohio retail electric service consumers at the federal level.

On energy sources:

- Requires an electric distribution utility by the end of 2025 to supply a portion of its SSO supply from advanced energy, in the amount of 25% of the number of kilowatt-hours it supplies in its certified distribution territory, and subject to other requirements including regarding the use of sustainable resources and regarding the location of the facility.

- Requires the PUCO to establish energy efficiency standards relating to the actual load growths and peak demands of electric distribution utilities and authorizes rules providing for revenue decoupling.

- Requires the PUCO to establish carbon control planning requirements for generating facilities and to establish greenhouse gas emission reporting requirements.

- Adds the following to the types of air quality projects that can be funded by the Ohio Air Quality Development Authority (OAQDA) and declares that both qualify as air and thermal pollution facilities under Section 13, Article VIII, Ohio Constitution: property, devices, or equipment used in the manufacture and production of any equipment that qualifies as an air quality project; and property, devices, or equipment that reduce air contaminant emissions through the generation of electricity using sustainable resources.

- In the manner of its current authority to fund air quality projects, authorizes OAQDA to issue revenue bonds to fund specified types of advanced energy projects and declares that such projects qualify as air and thermal pollution control facilities under the Ohio Constitution.

- Grants OAQDA authority regarding programs to achieve best cost rates for state-owned buildings, facilities, and operations, state-supported colleges and universities, willing local governments, and willing school districts through pooled purchases of electricity and the financing of taxable or tax-exempt prepayment of commodities; and regarding programs to achieve optimal cost electricity for key industrial and energy-intensive sectors.

- Grants OAQDA authority regarding programs to achieve optimal cost financing for new electric generating facilities and regarding the siting, financing, construction, operation, and risk reduction for next-generation base load generating systems, including clean coal facilities with carbon capture or sequestration or advanced nuclear power plants.

- Grants OAQDA authority regarding energy efficiency incentives, sustainable resource energy installations, and research and development regarding sustainable energy.

- Requires the Department of Natural Resources, the Ohio Environmental Protection Agency, and the PUCO jointly by rule to develop an interim policy framework for regulating pilot and demonstration, carbon sequestration activities in Ohio or sequestration products produced in Ohio.

TABLE OF CONTENTS

CONTENT AND OPERATION

Overview

The bill focuses on two main subject areas: electricity prices and electricity sources.

Regarding pricing, the bill focuses on the policy and process under which the electricity prices of Ohio's seven incumbent operating utilities[1] will be established after the scheduled expiration of the current rate plans under which they serve Ohio's retail electric market (December 31, 2010, for Dayton Power & Light; all others, the end of 2008). In brief, the bill preserves the right of customer choice enacted by the electric law of S.B. 3 of the 123rd General Assembly, extends the life of the utilities' current rate plans beyond their scheduled expiration, and allows future, cost-related adjustments to generation prices. However, if necessary, the PUCO can also regulate electric utilities under the traditional regulatory approach that applied to them before S.B. 3. The bill also repeals transitional (2001-2005) provisions of S.B. 3 that are obsolete.[2] However, it retains the competitive market provisions of that law, so it apparently does not intend that any such return to traditional regulation would reinstate the exclusive generation supplier status that existed for those utilities before S.B. 3.

The bill's pricing provisions do not focus only on generation service but also contain a provision regarding long-term planning for distribution system modernization and related cost recovery. It also requires a PUCO staff report on the value of utility participation in regional transmission organizations.

Regarding energy sources, the bill prohibits future utility divestitures of electric generating facilities without prior PUCO approval; grants authority for state-issued revenue bonds to finance advanced energy projects; provides for a 2025, advanced energy portfolio requirement for electric utilities and 2025 load growth and peak demand energy efficiency standards for electric utilities; requires a greenhouse gas emissions reporting system and requires carbon control planning for generating facilities; and provides for the development of an interim policy framework for regulating carbon sequestration in Ohio.

I. Electricity prices

Return to pre-S.B. 3 regulation

(R.C. 4905.31 and 4928.05(A)(1))

By way of background, S.B. 3 in effect repealed "traditional regulation" of electric generation service and declared that the price of generation service would be competitively market-determined starting January 1, 2001. Incumbent electric utilities no longer had state-established, exclusive service territories for generation service.[3] Other suppliers of generation service ("electric services companies," meaning generally, power marketers, power brokers, and aggregators) could compete to supply electricity to transmission/distribution customers of the incumbent utilities at each customer's option.[4] Too, incumbent electric utilities were free to vie for each other's generation customers.

To effect that competitive market, S.B. 3 generally revoked PUCO authority to regulate generation service under public utility law (R.C. Chapters 4901. to 4909., 4933., 4935., and 4963.) except as to service reliability and public safety and except as to standard service offers (SSOs) (see "***Price regulation***," below).

The bill allows the PUCO to decide to reinstate traditional regulation[5] of generation service (see **COMMENT** 1). The standard by which the PUCO could do so under the bill is that it finds that traditional regulation is necessary to implement the statutory electric services policy described next below.

What does it mean to return to "traditional regulation"? In brief, traditional regulation addresses all facets of utility operation that affect the provision of utility services, for example, utility stock and bond issuance, mergers and acquisitions, and, of course, service pricing. Under its duty to balance the interests of utilities and consumers, the PUCO determines a utility's "revenue requirement"--the amount of revenue a utility needs to cover all its operating costs and earn a rate of return on its overall plant investment. Largely based on consumption data and subject to PUCO approval, the utility then sets its rates so that they will provide it the opportunity to earn that revenue target.

This traditional ratemaking uses a snapshot method of identifying operating costs and plant investment so that, by statute, their calculation is contemporary to the time period for which rates are being determined. In general, any time a utility desires to change its rates because of any change in cost or investment, it has to file a "base rate case" with the PUCO, in which not the specific change, but all the asset, cost, revenue, and expense elements comprising a utility's rates are evaluated anew based on contemporary information.

Additional notable aspects of traditional regulation (which further relate to pricing under "***Energy security plan***," below) are that the basis for valuating utility assets and the basis for determining a utility's operating costs for rate-making purposes are specified in statute. For instance, under traditional regulation valuation must be done on an original cost basis,[6] for facilities "used and useful" in rendering service, and using books and records maintained by the utility in accordance with a uniform system of accounts specified by the PUCO (R.C. 4905.13, 4909.05(C), and 4909.15(A)). Further, the rate-making process of traditional regulation generally requires the filing of a base rate case application under a statute (R.C. 4909.18) that prescribes certain hearing and other requirements.

State electric services policy

(R.C. 4928.02)

The bill revises and adds to the current objectives of the state electric services policy enacted under S.B. 3. Among other reasons relating to how the electric law is implemented, the state policy is significant because, under the bill, it is integral to the criterion on which the PUCO can decide to return to pre-S.B. 3 regulation and because "consistency with" the policy is a criterion the bill requires the PUCO to weigh when approving generation prices other than under traditional regulation.

Under both current law and the bill, the statutory electric policy applies statewide, and the PUCO is required to ensure that the policy is effectuated (R.C. 4928.06(A), not in the bill).

The current policy objectives, which have their genesis in S.B. 3's competitive generation market concept, are as follows: (1) ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service, (2) ensure the availability of unbundled and comparable retail electric service that provides consumers with the supplier, price, terms, conditions, and quality options they elect to meet their respective needs, (3) ensure diversity of electricity supplies and suppliers, by giving consumers effective choice of supplies and suppliers and by encouraging the development of distributed and small generation facilities, (4) encourage innovation and market access for cost-effective supply- and demand-side retail electric service, (5) encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems of electric utilities in order to promote effective customer choice of retail electric service, (6) recognize the continuing emergence of competitive electricity markets through the development and implementation of flexible regulatory treatment, (7) ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, (8) ensure retail electric service consumers protection against unreasonable sales practices, market deficiencies, and market power, and (9) facilitate the state's effectiveness in the global economy.

The bill changes these policy objectives by adding seven new objectives and modifying three of the current objectives. Specifically, objective (4) above is changed to read: "encourage innovation and market access for *cost-effective retail electric service, including, but not limited to, demand-side management, time-differentiated pricing, and implementation of advanced metering infrastructure*."

Objective (5) above is changed to read: "encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems of electric utilities in order to promote *both* effective customer choice of retail electric service *and the development of performance standards and targets for service quality for all consumers, including annual achievement reports written in plain language*."

Objective (8) above is changed to read: "ensure retail electric service consumers *just and reasonable rates and* protection against unreasonable sales practices, market deficiencies, and market power."

The following new objectives are added to the state electric services policy: (1) ensure that an electric utility's transmission and distribution systems are available to a customer-generator or owner of distributed generation, so that the customer-generator or owner can market and deliver the electricity it produces, (2) preclude imbalances in knowledge and expertise among parties in a proceeding under the electric law to eliminate any appearance of disproportionate influence by any of those parties, (3) ensure that consumers and shareholders share the benefits of electric utility investment in facilities supplying retail electric generation service, (4) provide coherent, transparent means of giving appropriate incentives to technologies that can adapt successfully to potential environmental mandates, (5) protect at-risk populations when considering the implementation of any new advanced energy technology, (6) encourage implementation of distributed generation across customer classes through regular review and updating of rules governing critical issues such as, but not limited to, interconnection standards, standby charges, and net metering, and (7) encourage the education of small business owners in Ohio regarding the use of energy efficiency programs and advanced energy technologies in their businesses and encourage that use.

<u>Price regulation</u>

(R.C. 4928.14 and 4928.141)

Under S.B. 3, beginning generally in 2006 and currently, an electric utility's only duty regarding generation service is to provide a SSO that assures the availability of a firm supply of electricity to (1) any of its distribution customers that have never chosen an alternate generation supplier and (2) any customers that did choose but returned, if only briefly, to the utility, including because their supplier defaulted on its contract.[7] In general, for various reasons, the standard service offer of each incumbent utility over time has become, instead of an "essential service, fall-back" offer, *the* generation service offer for most of its distribution customers.

Current law enacted under S.B. 3 contemplates that a utility's standard service offer generation price will be "market-based." Alternately, it can be determined by competitive bidding, but not if the PUCO determines "at any time that a competitive bidding process is not required [because] other means to accomplish generally the same option for customers is readily available in the market and a reasonable means for customer participation is developed."

Generally, since the time S.B. 3's SSO requirement took effect, the incumbent utilities have operated under various SSOs that were developed by settlement among parties. These SSOs are typically referred to as "rate stabilization plans." Rate stabilization is an utility/PUCO-generated concept described as responding to an assessment that there is no effective competition in the electric generation market. The general nature of the utilities' rate stabilization plans is that they preserve generation prices at existing levels[8] but allow for price adjustments in relation to certain costs or under certain circumstances.

2009 (2011) SSOs

The bill retains the general standard service offer requirement for electric utilities. It declares that, as of January 1, 2009 (2011 for DP&L), as to each customer with a (bilateral or other) contract with a utility approved by the PUCO before October 28, 2007, a utility's SSO will consist of that contract price, exclusive of its transmission and distribution service components.

Also, as of that January 1, a utility's SSO, as to each of its customer classes, will consist of the total charges--exclusive of charges for transmission and distribution services--that are payable by customers on February 1, 2008 (2010 for DP&L) under the utility's current SSO rate plan and, further, that are subject to (1) any price adjustments for costs incurred by the utility and authorized under its existing rate plan for implementation on or after that February 1, but before the following January 1, and (2) to the extent they are not included in those total charges or price adjustments, any price adjustments for deferred costs authorized by PUCO order. (One effect of this provision is that any current rate stabilization charge[9] of a utility scheduled to expire under its current rate plan will continue.)

Later SSOs

Relative to its plan to take effect in 2009, the bill allows any utility to seek approval of a new SSO, in the form of either an "electric security plan" or a "market rate option." Such an ESP or MRO will take effect on the date the PUCO specifies in its approval order and supersedes the utility's prior SSO.

The bill expressly states that it does not preclude a utility for which an ESP has been approved under the bill from later filing an application for a MRO or vice versa; and that the PUCO has no authority to require a utility for which it has ever approved a MRO, to file an application for an ESP. Additionally, the bill does not limit a utility competing for generation customers in the certified distribution service territory of another utility.

The bill requires the PUCO to adopt rules governing the filing requirements for an application for a new SSO. Upon that filing, the PUCO must set the date and time for hearing, send written notice of the hearing to the utility, and publish notice of the hearing one time in a newspaper of general circulation in each county in the service area affected by the application.

Additionally, the bill contains a contract discovery provision. Specifically, subject to such protection for proprietary or confidential information as is determined appropriate by the PUCO, a utility must make available to any party to an ESP or MRO proceeding that submits an appropriate discovery request every contract or agreement that is relevant to the proceeding and is between the utility, or any of its affiliates, and a consumer, electric services company, political subdivision, or any party to the proceeding.

Electric security plans

Terms and conditions. Under an ESP, a utility's generation prices will change relative to changes in one or more costs specified in the utility's application and incurred by it to serve jurisdictional load in Ohio.

Under the bill, if the utility has entered into a contract or agreement with an affiliate for the provision of a competitive retail electric service, the PUCO must treat the affiliate's costs of providing that service as a cost of the utility under the ESP.

Any allowable adjustment under an ESP for a change in a capitalized cost must include a just and reasonable return on that cost.

Additionally, the amount of any price adjustment must be offset by any decrease in costs and change in kilowatt-hours sold that are associated with serving Ohio jurisdictional load, excluding a decrease that would have occurred pursuant to the scheduled expiration of a regulatory transition charge[10] charged by a utility. (Specifically, the bill excludes any reductions in amortization relating to costs recovered through a regulatory transition charge authorized by the PUCO as of February 1, 2008.) Thus, under an ESP, consumer rates will continue to include an amount relating to regulatory asset costs pertinent to S.B. 3.

Excluded as allowable costs under an ESP are any financial penalties, fines, court costs, and attorney's fees associated with violations of or noncompliances with federal or any state's environmental laws or with facilities' permits. Otherwise, any cost incurred by a utility to serve jurisdictional load in Ohio is allowable under an ESP. The bill enumerates certain of those costs, but an ESP is not limited to only those costs.

The enumerated costs are (1) environmental compliance costs for one or more specified generating facilities, (2) the cost of fuel for one or more specified generating facilities or the cost of purchased power (3) operating, maintenance, and other costs, including taxes, (4) costs of investment in one or more specified generating facilities, and (5) costs of providing standby and default service pursuant to electric law (specifically, R.C. 4928.14(A) and relettered (H)). An ESP that includes any of those costs can provide for automatic increases or decreases in the SSO price, but, in the case of a cost under (3), only if the cost was outside of the utility's control or responsibility.

In addition, costs in an ESP expressly can include (6) the cost of construction, in excess of $250 million, of an environmental retrofit to a specified, then-existing generating facility and (7) the cost of construction of one or more new, specified generating facilities that, superseding Power Siting Board authority under R.C. Chapter 4906., the PUCO determines and certificates the need for as to the SSO on the basis of resource planning projections developed in accordance with policies and procedures the PUCO must prescribe by rule (see **COMMENT** 2). Under the bill, then, the presumption of need that otherwise would apply under power siting law (R.C. 4906.10(A)(1)) to a generating facility does not apply to a facility described in (7).

In the case of a price adjustment for a cost described in (6) and (7), the bill requires that the adjustment be consistent with the rate-making formula and standards of continuing R.C. 4909.15 and consistent with procedures that ordinarily apply to a base rate case under R.C. 4909.18 "as [those procedures may be] applicable." Additionally, subject to such terms and conditions as the PUCO prescribes in its order approving the ESP, a price adjustment under (6) or (7) must be for the actual life of the facility.

If the costs of an advanced energy technology or facility implemented under the bill (see "***Advanced energy***," below) are included in the ESP, the portion of the SSO price attributable to those costs are not payable by any consumer that has exercised choice of supplier under continuing law (R.C. 4928.03), but only "to the extent" the PUCO determines that the advanced energy technology or facilities implemented by that supplier are comparable to that implemented by the utility under the bill at the time of the issuance of an ESP approval order. (That means that, if the PUCO determines that the supplier's advanced energy portfolio is only partially comparable to the utility's, a proportional amount of the part of the SSO price attributable to the utility's advanced energy costs included in the ESP will be payable.)

The bill requires that any adjustment for a particular cost in a utility's initial ESP application be determined using a baseline measure of cost as of February 1 of the year in which the utility's existing rate plan will expire (2008 or 2010, as applicable).

If a utility continues to provide its SSO pursuant to an ESP, for any later such application by the utility, the baseline measure must be the cost, and the associated kilowatt-hours sold, as determined under the utility's then-existing approved plan. With regard to a generating facility described in (6) and (7) above, associated decreases in cost and changes in kilowatt-hours sold must include, but are not limited to, retirement of all or part of any other generating facility, the cost of which had been included in the utility's rate base prior to the bill's effective date or was included in an ESP as a cost described in (4), (6), or (7) above (see **COMMENT** 3).

Aside from price adjustments, the bill additionally authorizes the PUCO to specify in an ESP any alternate standard, factors, or methodology that it must use, within the timeframe the PUCO specifies, to approve a MRO for the utility if it later files an application for that approval (see "***Market rate option***," below).

ESP approval. The bill allows the PUCO, when deciding upon an application for an ESP filed by a utility that transferred all or part of its generating facilities to an affiliate of the utility, and to the extent authorized by federal law, to consider purchased power or other contracts or agreements between the utility and its affiliates or between the utility and the holding company that owns or controls the utility.

Under the bill, the burden of proof regarding an ESP application is on the utility. The PUCO must find both of the following to approve, or modify and approve, an ESP: (1) the plan and prices it establishes are just and reasonable as to each customer class and are consistent with the state electric policy and (2) the utility is in compliance with the contract discovery provision mentioned earlier in this analysis.

In its approval order, the PUCO must prescribe such requirements necessary for the utility to implement "applicable" objectives of the state policy. The order also can provide a schedule and the procedural and substantive terms and conditions for periodic PUCO review of the ESP.

Market rate option

Terms and conditions. The bill states that, under a MRO, a utility's SSO price must be determined periodically through an open, competitive bidding process. Prior to the approval of the MRO, the utility must conduct such competitive bidding to establish the original price under the MRO.

MRO approval. As with an ESP, the burden of proof in a MRO proceeding is on the utility. The PUCO by order must approve, or modify and approve, the MRO if it determines all of the following are met: (1) the MRO and its prices are just and reasonable as to each customer class and are consistent with the state electric policy and (2) the utility is in compliance with the contract discovery provision of the bill.

Aside from those two standards, which also apply to ESP approval, the PUCO must determine for a MRO that (3) with respect to generation service, the relevant markets are subject to effective competition. For that purpose and unless the PUCO already established an effective competition standard, factors, or methodology in an earlier ESP for that utility as allowed under the bill, the PUCO must consider the factors prescribed in continuing electric law[11] and such other or additional factors as it can prescribe by rule. It also must prescribe by rule the methodology it will use to evaluate whether the effective competition standard is met.

In addition, for a MRO, the PUCO must determine that (4) the MRO price for a customer class as determined under the original competitive bidding is more favorable than, or at least comparable to, its price-to-compare for that class. That price-to-compare is a PUCO-determined price that is for the comparable time period and is established "in the manner of an [ESP]."

As with an ESP order, a MRO approval order must prescribe such requirements as are necessary for the utility to implement applicable objectives of the state electric policy. The order can provide the procedural and substantive terms and conditions for periodic PUCO review of the MRO. That review must provide for the reconciliation of the standard service offer price to ensure that the price is just and reasonable as to each customer class and consistent with the state policy.

Distribution system modernization; line extensions

(R.C. 4928.02 and 4928.111)

The bill requires an electric utility with a PUCO-approved ESP to file with the PUCO a "long-term energy delivery infrastructure modernization plan or any plan providing for the utility's recovery of costs and a just and reasonable rate of return on such infrastructure modernization." The plan must specify the initiatives the utility must take to improve electric service reliability by rebuilding, upgrading, or replacing the utility's distribution system. The plan must be filed as an application under the traditional ratemaking law (R.C. 4909.18) and therefore subject to any hearing and other requirements to the extent they would apply under that law.

The bill also contains a provision requiring the PUCO, in carrying out the state electric policy, to "consider rules as they apply to the costs of distribution infrastructure, including, but not limited to, lines extensions for the purpose of development" in Ohio. Under continuing law, a utility's filed distribution rates must "include an obligation to build distribution facilities when necessary to provide adequate distribution service, provided that a customer requesting that service may be required to pay all or part of the reasonable incremental cost of the new facilities, in accordance with rules, policy, precedents, or orders of the [PUCO]" (R.C. 4928.15(A)).

RTO participation; consumer advocate

(R.C. 4928.68)

The bill requires the PUCO to employ a federal energy advocate. The bill requires that person to examine the value of the participation of Ohio electric utilities in regional transmission organizations[12] and submit a report to the PUCO on whether continued participation of those utilities is in the interest of retail electric consumers.

Additionally under the bill, the PUCO employee must monitor the activities of the Federal Energy Regulatory Commission and other federal agencies and, represented by the Attorney General, must advocate on behalf of the interests of Ohio retail electric service consumers. Currently, there is one, state-level entity that functions as a consumer advocate: the Ohio Consumers' Counsel, who advocates on both the state and federal levels, on behalf of the residential consumers of electric, gas, natural gas, and certain other public utilities (R.C. Chapter 4911.). The PUCO itself often is a party to federal proceedings.

Governmental aggregation

(R.C. 4928.20 and 4928.21)

Current law authorizes the electric load of electric customers to be aggregated for the purpose of purchasing retail electric generation (R.C. 4928.03). Aggregators performing that function include governmental aggregators, specifically, municipalities, townships, and counties that can aggregate the electric load of customers within their respective jurisdictions. Current law establishes various requirements for and limitations on a governmental aggregation, including, for instance, a popular vote on the question of whether the local government can aggregate load without first obtaining the individual permission of each customer.

The bill changes current law's limitation that, in the case of such an "automatic" governmental aggregation, the local government must allow any person that is so enrolled in the aggregation an opportunity to opt out of the aggregation every *two* years, without paying a switching fee. Under the bill, a customer can opt-out *up to every four years* without paying a switching fee.

II. Energy sources

Divestiture policy

(R.C. 4928.17(E))

Current law enacted by S.B. 3 authorizes an electric utility to divest itself of any generating asset without prior PUCO approval. The bill prohibits an electric utility selling or transferring any generating facility it owns in whole or in part to any person without prior PUCO approval. (Prior to S.B. 3, an electric utility, like any other public utility, was subject to policy and a process regarding such prior PUCO approval under R.C. 4905.48 (not in the bill). PUCO approval authority under the bill does not reference that statute.)

Advanced energy portfolio

(R.C. 4928.142)

Advanced energy requirement

The bill requires that, by the end of 2025, each electric distribution utility must comply with the bill's requirement for advanced energy in its SSO supply portfolio. An effect of the bill is that it allows the utility to decide the manner and timing of its compliance with that requirement. The requisite amount of advanced energy for each utility is 25% of the total number of kilowatt-hours of electricity the utility supplies to any and all electric consumers whose electric load centers are located in its certified distribution service territory. The bill expressly states that it does not preclude a utility from providing a greater percentage.

In fulfilling the 25% requirement, the utility must comply with the following standards: (1) at least 50% of the advanced energy it implements by the end of 2025 must be generated from sustainable resources and must include solar power, and the remainder must be supplied from advanced energy facilities, (2) at least 50% of the advanced energy it implements by the end of 2025 must be met through facilities located in Ohio, (3) the utility must comply with the advanced energy requirement in a manner that considers available technology, costs, job creation, and economic impacts, and (4) to be counted as an advanced energy technology or facility, its on-site construction must be initiated after the bill's effective date. (The effect of (4) is to allow current advanced energy technology or facilities that are not yet in their on-site construction phase to be counted toward the 2025 standard.) Once counted, a particular technology or facility remains counted for purposes of the utility's compliance with the bill's advanced energy requirement.

The bill defines "sustainable resources" as including, but not limited to, solar; wind, tidal or wave; biomass, including, but not limited to, biomass involving the use of tree parts; landfill gas; biofuel; hydro; or geothermal resources that are used in the generation of electricity.

The bill also defines "sustainable resources" as including fuel cells powered by those resources. As noted in (4) below, fuel cells used to generate electricity also count as "advanced energy facilities" under the bill. (Apparently, the same fuel cell powered by sustainable resources could then be counted twice, for purpose of compliance with both the sustainable resources and advanced energy requirements of the bill.)

The bill defines "advanced energy facilities" as consisting of methods or any modifications or replacements of any property, processes, devices, structures, or equipment that meet any of the following: (1) regarding clean coal technology, technology that includes the design capability to control or prevent the emission of carbon dioxide, which design capability the commission shall adopt by rule and shall be based on economically feasible best available technology or, in the absence of a determined best available technology, shall be of the highest level of economically feasible design capability for which there exists generally accepted scientific opinion, (2) regarding advanced nuclear energy production, generation III technology as defined by the Nuclear Regulatory Commission, other later technology, or "significant improvements to existing facilities," (3) fuel cells used to generate electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid fuel cell, (4) regarding cogeneration technology, technology using a heat engine or power station to generate electricity and useful heat simultaneously. Under the bill, "advanced energy facility" further includes any property or system to be used in whole or in part for any of the purposes in (1) to (4) above, whether another purpose also is served, and any property or system incidental to or that has to do with, or the end purpose of which is, any of the foregoing.

PUCO strategy; advisory committee

The bill requires the PUCO to submit to the General Assembly an annual report describing the compliance of electric distribution utilities with the bill's advanced energy requirement and describing any interim goals or strategy for utility compliance or for encouraging the use of advanced energy in supplying Ohio's electricity needs in a manner that considers available technology, costs, job creation, and economic impacts. The PUCO must allow and consider public comments on the report before submitting it. The bill expressly states that nothing in the report binds any person, including any utility for the purpose of its compliance with the advanced energy requirement or the purpose of enforcing that requirement.

The bill additionally requires the Governor to appoint an advanced energy advisory committee in consultation with the chair of the PUCO. The committee is charged with examining available technology for and related timetables, goals, and costs of the bill's advanced energy requirement and semiannually submitting a report of its recommendations to the PUCO.

Enforcement and exception to compliance

Under the bill, if the PUCO determines, after notice and hearing, that the utility has failed to comply with the 2025-25% requirement, it must issue an order requiring the utility to comply fully within such time as must be specified in the order. The order must specify the process and schedule for later verifying the utility's compliance to the PUCO.

However, the PUCO's authority to order a utility's full compliance is subject to a price limitation: under the bill, the PUCO cannot require full compliance "to the extent that" the ratio between the blended advanced energy and nonadvanced energy price in 2025 and the portion of that price attributable to nonadvanced energy exceeds 1.03. (In other words, full compliance cannot be required if the utility's overall standard service price in 2025 would rise by more than 3% if the utility were made to fully comply with the 2025-25% requirement; and the PUCO could require something less than full compliance, up "to the extent that" that price effect would not occur.)

Regarding financial penalties for noncompliance, the bill authorizes the PUCO to pursue mandamus, injunction, or other civil remedies against a utility to compel its compliance with a compliance order under the bill or with an order in a later proceeding in which it determines the utility has failed to comply with the compliance order. The bill also authorizes the PUCO to assess forfeitures. The maximum amount of the forfeiture is $10,000 per day per noncompliance. (R.C. 4928.16(B)(2), referencing R.C. 4905.54 *et seq.*) (That amount is the same as that which applies to a public utility under traditional regulation and can otherwise apply to an electric distribution utility for violations of or noncompliances with electric law under R.C. Chapter 4928.) Under continuing law, such forfeitures are deposited to the credit of the general revenue fund (R.C. 113.09).

Energy efficiency standards

(R.C. 4928.64)

The bill requires the PUCO to establish by rule energy efficiency standards applicable to electric distribution utilities. Under the rules, a utility must implement energy efficiency measures that will result in not less than 25% of actual growth in its electric load and not less than 10% of its total peak demand being achieved through those measures by 2025. The rules must include a requirement that an electric distribution utility provide a customer upon request with two years of consumption data in an accessible form.

Additionally, the rules may provide for "decoupling." (Although not further described in the bill, this term generally refers to a policy that detaches utility earnings from amount of commodity sold.)

Greenhouse gas emissions, carbon control

(R.C. 4928.69)

The bill requires the PUCO to adopt rules establishing greenhouse gas[13] emission reporting requirements (see **COMMENT** 4). The rules must include participation in the Climate Registry. The Registry's web site describes the Registry as "a collaboration between states, provinces, and tribes aimed at developing and managing a common greenhouse gas emissions reporting system with high integrity that is capable of supporting various greenhouse gas emissions reporting and reduction policies for its member states and tribes and reporting entities."[14]

The bill also requires the PUCO to adopt rules establishing carbon control planning requirements for each electric generating facility located in Ohio that emits greenhouse gases, including facilities in operation on the bill's effective date.

Carbon sequestration

(R.C. 1551.41)

The bill requires the Department of Natural Resources, the Ohio Environmental Protection Agency, and the PUCO, jointly by rule, to develop an interim policy framework for supervision and regulation by the agencies of pilot and demonstration, carbon sequestration activities located in Ohio and sequestration products produced in Ohio.

State revenue bonds

(R.C. 122.41, 122.451, 3706.01 through 3706.18, and 4905.40)

Current law authorizes the Ohio Air Quality Development Authority (OAQDA) to issue revenue bonds and notes, the proceeds of which can be used to fund the cost[15] of air quality projects. Funding can come in the form of an OAQDA loan or grant or can otherwise be paid from bond proceeds.

OAQDA's financing authority is granted in relation to the enactment of Section 13, Article VIII, Ohio Constitution (referenced in R.C. 3706.01(G) and 3706.03(A)). That constitutional provision empowers state government to lend the state's aid and credit to private entities (by issuing of debt backed by revenues other than tax revenues) for the express purposes of controlling air, water, and thermal pollution or disposing of solid waste. But the constitutional provision also includes a prohibition that,

> except for facilities for pollution control or solid waste disposal, as determined by law, no guarantees or loans and no lending of aid or credit shall be made [by statute or otherwise] for facilities to be constructed for the purpose of providing electric or gas utility service to the public.

The bill adds to the types of air quality projects that can be funded by the OAQDA. It also gives OAQDA new, identical, statutory authority to issue revenue bonds for advanced energy projects. The latter also involves extending to advanced energy projects two existing statutory provisions relating to a Department of Development mortgage insurance program for air quality, wastewater, or solid wastes projects.

The bill additionally expressly denies OAQDA the authority to build, own, or operate an air quality facility or advanced energy facility, except as may be required to effect a facility's financing.

Air quality projects

Projects currently eligible for OAQDA funding are, in brief: (1) methods, or modifications or replacements of property, processes, devices, structures, or equipment, directed at air contaminants,[16] (2) property used for collecting, storing, treating, using, processing, or disposing of a by-product or solid waste resulting from a project described in (1), (3) motor vehicle inspection stations and station equipment, (4) ethanol or other biofuel facilities and facility equipment, (5) property, devices, or equipment that reduce emissions of air contaminants through improvements in energy efficiency or energy conservation, (6) research and development projects under the Ohio Coal Development Office, (7) property used for collecting, storing, treating, using, processing, or disposing of a by-product or solid waste resulting from a project described in (6) or from the use of clean coal technology, excluding property used primarily for other subsequent commercial purposes, (8) property that is part of the FutureGen project[17] or related to its siting, and (9) property or any system to be used for any of the purposes described in (1) to (8), whether another purpose is also served, and any property or system incidental to or that has to do with, or the end purpose of which is, any of (1) to (8) above.

The bill makes the following newly eligible as "air quality projects" and also expands (9) above to include these new types of projects: (1) property, devices, or equipment necessary for the manufacture and production of any equipment that qualifies as an air quality project, and (2) property, devices, or equipment that reduce air contaminant emissions through the generation of electricity using sustainable resources. The bill declares that both of these new types of air quality projects qualify as facilities for the control of air pollution and thermal pollution related to air under Section 13, Article VIII, Ohio Constitution (R.C. 3706.01(G)). "Sustainable resources" under the bill include, but are not limited to, solar, wind, tidal or wave, biomass, including, biomass involving the use of tree parts, biofuel, hydro, or geothermal resources; and include fuel cells powered by sustainable resources.

Advanced energy projects

OAQDA authority to fund advanced energy projects under the bill, and the statutory requirements for bonds and all other funding details, mirror those of existing law as to air quality projects. Similar to the law regarding air quality projects, the bill declares that advanced energy projects for industry, commerce, distribution, or research, including public utility companies, qualify as facilities for the control of air pollution and thermal pollution related to air under Section 13, Article VIII, Ohio Constitution (R.C. 3706.03(A)). This declaration is subject to the limitation within that constitutional provision, as noted above.

Under the bill, "advanced energy projects" consist of methods or of modifications or replacements of property, processes, devices, structures, or equipment, regarding any of the following: (1) for clean coal technology, technology that includes the design capability to control or prevent the emission of carbon dioxide, which design capability the PUCO must adopt by rule and must be based on economically feasible best available technology or, in the absence of a determined best available technology, shall be of the highest level of economically feasible design capability for which there exists generally accepted scientific opinion, (2) for advanced nuclear energy production, generation III technology as defined by the Nuclear Regulatory Commission, other later technology, or "significant improvements to existing facilities," (3) electric generating fuel cells including, but not limited to, proton exchange membrane fuel cells, phosphoric acid fuel cells, molten carbonate fuel cells, or solid fuel cells, and (4) cogeneration technology using a heat engine or power station to generate electricity and useful heat simultaneously. An advanced energy project also includes any property or system to be used in whole or in part for (1) to (4) above, whether another purpose also is served, and any property or system incidental to or that has to do with, or the end purpose of which is, any of (1) to (4).

Additional OAQDA authority

(R.C. 3706.04)

Current law lists a number of general powers of the OAQDA with respect to air quality projects, including, for example, adopting an official OAQDA seal, making loans and grants, acquiring or constructing property, engaging in certain competitive bidding, and receiving federal funds. The bill extends those same powers with respect to advanced energy projects funded by OAQDA.

Further, the bill establishes additional OAQDA authority. The bill authorizes OAQDA to develop, encourage, promote, support, and implement programs to achieve best cost rates for state-owned buildings, facilities, and operations, state-supported colleges and universities, willing local governments, and willing school districts through pooled purchases of electricity and the financing of taxable or tax-exempt prepayment of commodities. OAQDA additionally may develop, encourage, promote, support, and implement programs to attract and retain key industrial and energy-intensive sectors of Ohio's economy.

The bill also empowers OAQDA to develop, encourage, promote, support, and implement programs to achieve optimal cost financing for electric generating facilities to be constructed on or after January 1, 2009. And, it empowers OAQDA to lead, encourage, promote, and support siting,[18] financing, construction, and operation for, and reduce the costs of associated risks of, early implementations of next-generation base load generating systems, including clean coal generating facilities with carbon capture or sequestration or advanced nuclear power plants.

Additional authority is granted for OAQDA to develop, encourage, and provide incentives for investments in energy efficiency; develop, encourage, promote, and support implementation in Ohio of sustainable resource energy installations; and engage in and coordinate state-supported energy research and development with respect to reliable, affordable, and sustainable energy in Ohio.

The bill does not address funding for the additional OAQDA authority it confers.

COMMENT

1. The bill is not clear as to whether PUCO authority to institute traditional regulation of generation service also includes authority to go back and forth between that regulatory approach and the framework otherwise established under R.C. Chapter 4928.

2. The bill authorizes the PUCO to certificate the need for a new generating facility under an ESP. If that is the only intended authority, the bill's reference to superseding R.C. Chapter 4906. might be made more precise by referencing only R.C. 4906.10(A)(1), the specific provision under which the Power Siting Board would otherwise determine need for a generating facility.

3. The use of "rate base" is not clear in R.C. 4928.14(D)(2)(b) as to whether it intends to refer to an asset included in the utility's rates under traditional regulation prior to S.B. 3's effective date or intends to mean the utility's rates in effect any time prior to the bill's effective date.

4. The bill is not clear as to whom the PUCO's greenhouse gas reporting and carbon control planning requirements under R.C. 4928.69 will apply, that is, as to public utilities the PUCO regulates and/or other owners of electric generation. If it includes the latter, there is no authority under current law or the bill for the PUCO to enforce compliance as to those nonutility owners.

HISTORY

ACTION	DATE
Introduced	09-25-07
Reported, S. Energy and Public Utilities	10-31-07
Passed Senate (32-0)	10-31-07

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[1] Duke Energy Ohio, Cleveland Electric Illuminating, Ohio Edison, Toledo Edison, Ohio Power, Columbus Southern Power, and Dayton Power & Light.

[2] R.C. 4928.31, 4928.32, 4928.33, 4928.34, 4928.35, 4928.36, 4928.37, 4928.38, 4928.39, 4928.40, 4928.41, 4928.42, 4928.431, and 4928.44.

[3] Although such exclusive "certified" territories continued as to other components of electric service, such as distribution (R.C. 4933.81 *et seq.*, not in the bill).

[4] Generally, neither current law nor the bill affect the right of a municipal utility to provide electric service within its jurisdiction as established under the Ohio Constitution; nor do they affect the exclusive authority of an electric cooperative to provide electric service to its members within its certified territory as that territory is established by statute. Within the limitations of those respective authorities, both municipals and electric cooperatives compete with electric utilities and electric services companies.

[5] A return to traditional regulation does not exactly mean a return to pre-S.B. 3 regulation, since S.B. 3 repealed certain provisions of traditional regulation, such as provisions authorizing an electric fuel component in rates and provisions addressing environmental compliance facilities of electric utilities, and amended other provisions.

[6] As opposed to some other basis, for example, original cost less depreciation or replacement cost new.

[7] More fully, a customer can return under current law to the SSO of its incumbent utility if the customer's supplier (1) has defaulted on its contract, (2) is in receivership, (3) has filed for

bankruptcy, (4) is no longer capable of providing the service, (5) is unable to provide delivery to transmission or distribution facilities for such reasonable period of time as the PUCO may specify by rule, or (6) has had its PUCO certification suspended, conditionally rescinded, or rescinded (R.C. 4928.14(C); under the bill, the division is changed to (H)).

[8] Generally meaning, at the level of the utility's pre-2000 price of electricity, determined through an unbundling process that required the price of generation to be the amount that remained after all other electric service components were removed from the bundled price for electric service that reflected the vertical integration of Ohio electric utilities prior to S.B. 3. Those bundled prices had not changed since the utilities' last rate cases, which generally occurred in the late 1980s to mid-90s, so, they have not been evaluated since then under the rate-making criteria of traditional regulation.

[9] For instance, in the case of Cleveland Electric Illuminating, Toledo Edison, and Ohio Edison, that charge was set to equal the generation transition charge authorized for the utilities' five-year, post-S.B. 3 period. The PUCO recognized the charge as covering their cost of reserving and supplying generation under the SSO requirement.

[10] A regulatory transition charge is a charge that S.B. 3 permitted the PUCO to grant an electric utility so that it could collect revenue from customers for pre-S.B. 3 regulatory assets that met the definition of a "transition cost" under S.B. 3. Under S.B. 3, that revenue period for a utility was to end not later than December 31, 2010. "Regulatory assets" are the unamortized amounts capitalized or deferred on a utility's books of account per PUCO orders and can include such items as deferred PIPP (Percentage of Income Payment Plan) arrears or deferred demand-side management costs (R.C. 4928.01(A)(26), 4928.39, and 4928.40 of current law).

[11] Under R.C. 4928.06(D), these factors include, but are not limited to, (1) the number and size of alternative providers of the service, (2) the extent to which the service is available from alternative suppliers in the relevant market, (3) the ability of alternative suppliers to make functionally equivalent or substitute services readily available at competitive prices, terms, and conditions, and (4) other indicators of market power, which may include market share, growth in market share, ease of entry, and the affiliation of suppliers of services.

[12] In brief, these "RTOs" coordinate the transportation of electricity over transmission lines of any number of participating utilities. Ohio utilities currently belong to either or both of two such RTOs: MISO (The Midwest Independent System Operator) or PJM Interconnection.

[13] "[G]reenhouse gases allow sunlight to enter the atmosphere freely. When sunlight strikes the Earth's surface, some of it is reflected back towards space as infrared radiation (heat). Greenhouse gases absorb this infrared radiation and trap the heat in the atmosphere. . . . Some of [the gases] occur in nature (water vapor, carbon dioxide, methane, and nitrous oxide), while others are exclusively human-made (like gases used for aerosols). . . . During the past 20 years, about three-quarters of human-made carbon dioxide emissions were from burning fossil fuels." From the U.S. Energy Information Administration, at < http://www.eia.doe.gov/oiaf/1605/ggccebro/chapter1.html>.

[14] <http://www.theclimateregistry.org/>. According to the web site, as of August 9, 2007, Ohio is listed as having joined the Registry, along with all other states except Alaska, Texas, Louisiana, Mississippi, Arkansas, North Dakota, South Dakota, Nebraska, Kentucky, Indiana, and West

Virginia. The Ohio contact listed on the site is the Director of Ohio EPA. The state's listing currently enables a utility's voluntary participation in the Registry.

[15] "Cost" means the cost of acquisition and construction, the cost of acquisition of all land, rights-of-way, property rights, easements, franchise rights, and interests required for such acquisition and construction, the cost of demolishing or removing any buildings or structures on land so acquired, including the cost of acquiring any lands to which such buildings or structures may be moved, the cost of acquiring or constructing and equipping a principal OAQDA office and sub-offices, the cost of diverting highways, interchange of highways, and access roads to private property, including the cost of land or easements for such access roads, the cost of public utility and common carrier relocation or duplication, the cost of all machinery, furnishings, and equipment, financing charges, interest prior to and during construction and for no more than 18 months after completion of construction, engineering, expenses of research and development, the cost of any commodity contract, including related fees and expenses, legal expenses, plans, specifications, surveys, studies, cost and revenue estimates, working capital, other expenses necessary or incident to determining the feasibility or practicability of acquiring or constructing a project, administrative expense, and such other expense as may be necessary or incident to the acquisition or construction of the project, the financing of such acquisition or construction, including the amount authorized in the OAQDA bond resolution, the financing of the placing of such project in operation, and any obligation, cost, or expense incurred by any governmental agency or person for surveys, borings, preparation of plans and specifications, and other engineering services, or any other cost described above (R.C. 3706.01 (I)).

[16] That is, methods, modifications, or replacements that remove, reduce, prevent, contain, alter, convey, store, disperse, or dispose of particulate matter, dust, fumes, gas, mist, smoke, noise, vapor, heat, radioactivity, radiation, or odorous substances, or substances containing those contaminants, or that render them less noxious or reduce their concentration in the air (R.C. 3706.01(C) and (G)).

[17] This project is a coal-fueled, zero-emissions power plant designed to prove the feasibility of producing electricity and hydrogen from coal and nearly eliminating carbon dioxide emissions through capture and permanent storage. The future site of the project has been narrowed by the U.S. Department of Energy to Texas or Illinois.

[18] This apparently intends that, if the facilities qualify as major utility facilities under power siting law, OAQDA would lead, encourage, promote, and support siting of such facilities before the Power Siting Board.