Appendix G:

GAO Report to the Ranking Member, Committee on Energy and Natural Resources, U.S. Senate: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements

Appendix H:

EIA: Ohio Natural Gas Consumption by End User

Appendix I:

2012 EIA-860 Data Form - Generator Data, Ohio NGCC

2012 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Prime Mover	Status	Nameplate Capacity (MW)	Summer Capacity (MW)	Winter Capacity (MW)	Unit Code	Operating Month	Operating Year	Energy Source 1	Energy Source 2
733	Appalachian Power Co	55350	Dresden Energy Facility	OH	Muskingum	1	CT	OP	198.9	158.3	183.3		2	2012	NG	DFO
733	Appalachian Power Co	55350	Dresden Energy Facility	OH	Muskingum	2	CT	OP	198.9	158.3	183.3		2	2012	NG	DFO
733	Appalachian Power Co	55350	Dresden Energy Facility	OH	Muskingum	3	CA	OP	280.5	223.4	258.4		2	2012	NG	DFO
14006	Ohio Power Co	55503	AEP Waterford Facility	OH	Washington	CTG1	CT	OP	174.2	155.0	161.0		8	2003	NG	
14006	Ohio Power Co	55503	AEP Waterford Facility	OH	Washington	CTG2	CT	OP	174.2	156.0	161.0		8	2003	NG	
14006	Ohio Power Co	55503	AEP Waterford Facility	OH	Washington	CTG3	CT	OP	174.2	156.0	161.0		8	2003	NG	
14006	Ohio Power Co	55503	AEP Waterford Facility	OH	Washington	ST1	CA	OP	399.0	345.0	367.0		8	2003	NG	
40577	American Mun Power-Ohio, Inc	55701	Fremont Energy Center	OH	SANDUSKY	CA01	CA	OP	358.7	330.5	341.7		1	2012	NG	
40577	American Mun Power-Ohio, Inc	55701	Fremont Energy Center	OH	SANDUSKY	CT01	CT	OP	190.4	166.4	187.3		1	2012	NG	
40577	American Mun Power-Ohio, Inc	55701	Fremont Energy Center	OH	SANDUSKY	CT02	CT	OP	190.4	166.4	187.3		1	2012	NG	
57393	Duke Energy Commercial Asset Management	55397	Washington Energy Facility	OH	Washington	CT1	CT	OP	198.9	169.0	175.0		6	2002	NG	
57393	Duke Energy Commercial Asset Management	55397	Washington Energy Facility	OH	Washington	CT2	CT	OP	198.9	169.0	175.0		6	2002	NG	
57393	Duke Energy Commercial Asset Management	55397	Washington Energy Facility	OH	Washington	ST1	CA	OP	317.1	288.0	298.0		6	2002	NG	
57393	Duke Energy Commercial Asset Management	55736	Hanging Rock Energy Facility	OH	Lawrence	1GT1	CT	OP	163.5	169.0	175.0		6	2003	NG	
57393	Duke Energy Commercial Asset Management	55736	Hanging Rock Energy Facility	OH	Lawrence	1GT2	CT	OP	163.5	169.0	175.0		6	2003	NG	
57393	Duke Energy Commercial Asset Management	55736	Hanging Rock Energy Facility	OH	Lawrence	1ST	CA	OP	317.1	288.0	298.0		6	2003	NG	
57393	Duke Energy Commercial Asset Management	55736	Hanging Rock Energy Facility	OH	Lawrence	2GT1	CT	OP	163.5	169.0	175.0		7	2003	NG	
57393	Duke Energy Commercial Asset Management	55736	Hanging Rock Energy Facility	OH	Lawrence	2GT2	CT	OP	163.5	169.0	175.0		7	2003	NG	
57393	Duke Energy Commercial Asset Management	55736	Hanging Rock Energy Facility	OH	Lawrence	2ST	CA	OP	317.1	288.0	298.0		7	2003	NG	
								TOTAL	4,342.5	3,895.3						

	Data 1: Ohio Natural Gas Consumption by End Use							
	NA1490_SOH_2	NA1470_SOH_2	NA1840_SOH_2	NA1850_SOH_2	NA1480_SOH_2	N3060OH2	N3010OH2	N3020OH2
Date	Ohio Natural Gas Total Consumption (MMcf)	Ohio Natural Gas Lease and Plant Fuel Consumption (MMcf)	Ohio Natural Gas Lease Fuel Consumption (MMcf)	Ohio Natural Gas Plant Fuel Consumption (MMcf)	Ohio Natural Gas Pipeline and Distribution Use (MMcf)	Natural Gas Delivered to Consumers in Ohio (Including Vehicle Fuel) (MMcf)	Ohio Natural Gas Residential Consumption (MMcf)	Natural Gas Deliveries to Commercial Consumers (Including Vehicle Fuel through 1996) in Ohio (MMcf)
1967		2656					442360	153376
1968		3505					444964	165414
1969		2879					456414	175372
1970		3140					459972	183412
1971		4302					460820	189791
1972		3397					478331	208068
1973		3548					439212	196663
1974		2957					435800	192497
1975		2925					427817	169357
1976		2742					440190	179392
1977		2814					401928	149011
1978		3477					416721	172429
1979		22094					373631	158117
1980		1941					393759	166210
1981		1776					377134	161110
1982		3671					369437	157664
1983		4377	4327	50			329647	143568
1984		5741	5678	63			350296	155350
1985		5442	5371	71			327591	143311
1986		5243	5174	69			327300	139119
1987		5802	5706	96			326480	146983
1988		4869	4781	88			350612	158790
1989		3876	3789	87			359148	161516
1990		5129	5115	14			308321	143503
1991		1476	1462	14			321724	150339
1992		1450	1434	16			340628	160645
1993		1366	1346	20			354110	164044
1994		1332	1296	36			343331	166798
1995		1283	1251	32			357754	175160
1996		1230	1193	37			374824	189966
1997	897693	1201	1162	39	19453	877039	354543	183838
1998	811384	1125	1085	40	17641	792617	296576	156630
1999	841966		1035	42	17441	823448	318214	167573
2000	890962		986	43	18490	871444	343920	177917
2001	804243		983	40	15502	787719	308534	172555
2002	830955		972	37	16215	813735	321317	163274
2003	848388		936	17	14872	832563	343037	179611
2004	825753		894	18	12757	812084	320823	170240
2005	825961		833	12	13356	811759	322697	166693
2006	742359		855	8	12233	729264	272261	146930
2007	806350		872	5	13740	791733	299577	160580
2008	792247		840	0	11219	780187	306529	167070
2009	740925		879	0	16575	723471	292429	160612
2010	784293		773	0	15816	767704	283703	156407
2011	823548		781	0	14258	808509	286132	161408
2012	842959		836	127	9559	832437	250871	145482
2013							291198	168177

	N3035OH2	NA1570_SOH_2	N3045OH2
Date	Ohio Natural Gas Industrial Consumption (MMcf)	Ohio Natural Gas Vehicle Fuel Consumption (MMcf)	Ohio Natural Gas Deliveries to Electric Power Consumers (MMcf)
1967			
1968			
1969			
1970			
1971			
1972			
1973			
1974			
1975			
1976			
1977			
1978			
1979			
1980			
1981			
1982			
1983			
1984			
1985			
1986			
1987			
1988		0	
1989		0	
1990		73	
1991		67	
1992		59	
1993		44	
1994		48	
1995		187	
1996		229	
1997	334874	294	3491
1998	331122	309	7981
1999	325887	386	11388
2000	339060	424	10123
2001	295556	529	10545
2002	305883	539	22722
2003	290483	659	18774
2004	302023	740	18258
2005	293985	444	27941
2006	286487	403	23184
2007	293976	308	37292
2008	282834	261	23493
2009	232632	130	37668
2010	269287	146	58161
2011	268034	88	92845
2012	264405	89	171590
2013		138	160241

United States Government Accountability Office

Report to the Ranking Member, Committee on Energy and Natural Resources, U.S. Senate

August 2014

EPA REGULATIONS AND ELECTRICITY

Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements

GAO-14-672

GAO Highlights

Highlights of GAO-14-672, a report to the Ranking Member, Committee on Energy and Natural Resources, U.S. Senate

August 2014

EPA REGULATIONS AND ELECTRICITY

Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements

Why GAO Did This Study

EPA recently proposed or finalized four regulations affecting coal-fueled electricity generating units, which provide about 37 percent of the nation's electricity supply. These regulations are the: (1) Cross-State Air Pollution Rule; (2) Mercury and Air Toxics Standards; (3) Cooling Water Intake Structures regulation; and (4) Disposal of Coal Combustion Residuals regulation. In 2012, GAO reported that, in response to these regulations and other factors such as low natural gas prices, companies might retire or retrofit some units. GAO reported that these actions may increase electricity prices and, according to some stakeholders, may affect reliability--the ability to meet consumers' demand—in some regions. In 2012, GAO recommended that DOE, EPA, and FERC develop and document a formal, joint process to monitor industry's progress responding to these regulations. In June 2014, EPA proposed new regulations to reduce carbon dioxide emissions that will also affect these units.

GAO was asked to update its 2012 report. This report examines (1) agencies' efforts to respond to GAO's recommendation and (2) what is known about planned retirements and retrofits. GAO reviewed documents, analyzed data, and interviewed agency officials and stakeholders.

What GAO Recommends

GAO is not making new recommendations but believes it is important that these agencies jointly monitor industry progress and fully document these steps as GAO recommended in 2012. The agencies concurred with GAO's findings.

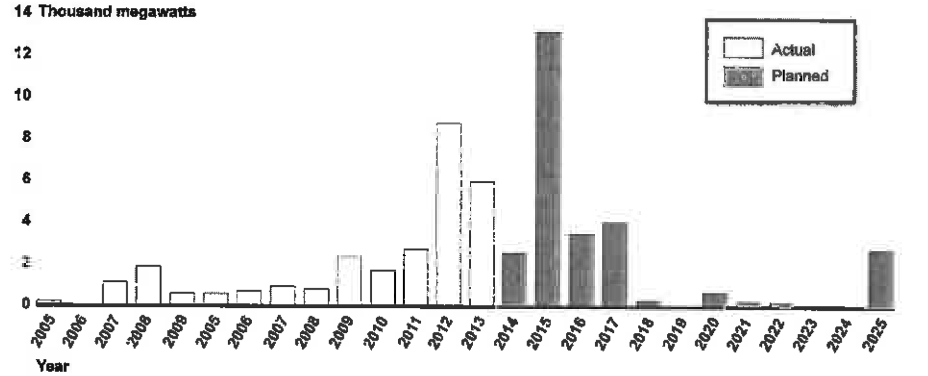
View GAO-14-672. For more information, contact Frank Rusco at (202) 512-3841 or ruscof@gao.gov.

What GAO Found

The Department of Energy (DOE), the Environmental Protection Agency (EPA), and the Federal Energy Regulatory Commission (FERC) have taken initial steps to implement a recommendation GAO made in 2012 that these agencies develop and document a joint process to monitor industry's progress in responding to four proposed or finalized EPA regulations affecting coal-fueled generating units. GAO concluded that such a process was needed until at least 2017 to monitor the complexity of implementation and extent of potential effects on price and reliability. Since that time, DOE, EPA, and FERC have taken initial steps to monitor industry progress responding to EPA regulations including jointly conducting regular meetings with key industry stakeholders. Currently, these monitoring efforts are primarily focused on industry's implementation of one of four EPA regulations—the Mercury and Air Toxics Standards—and the regions with a large amount of capacity that must comply with that regulation. Agency officials told GAO that in light of EPA's recent and pending actions on regulations including those to reduce carbon dioxide emissions from existing generating units, these coordination efforts may need to be revisited.

According to GAO's analysis of public data, power companies now plan to retire a greater percentage of coal-fueled generating capacity and retrofit less capacity with environmental controls than the estimates GAO reported in July 2012. About 13 percent of coal-fueled generating capacity—42,192 megawatts (MW)—has either been retired since 2012 or is planned for retirement by 2025, which exceeds the estimates of 2 to 12 percent of capacity that GAO reported in 2012 (see fig.). The units that power companies have retired or plan to retire are generally older, smaller, more polluting and not used extensively, with some exceptions. For example, some larger generating units are also planned for retirement. In addition, the capacity is geographically concentrated in four states: Ohio (14 percent), Pennsylvania (11 percent), Kentucky (7 percent), and West Virginia (6 percent). GAO's analysis identified about 70,000 MW of generating capacity that has either completed some type of retrofit to reduce sulfur dioxide, nitrogen oxides, or particulate matter since 2012 or plan to complete one by 2025, which is less than the estimate of 102,000 MW GAO reported in 2012.

Capacity of Actual and Planned Retirements of Coal-Fueled Generating Units, 2005-2025



Source: GAO analysis of SNL Financial data. | GAO-14-672

Contents

Abbreviations

Btu	British thermal unit
CCR	Disposal of Coal Combustion Residuals from Electric Utilities regulation
CSAPR	Cross-State Air Pollution Rule
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
kWh	kilowatt-hour
MATS	Mercury and Air Toxics Standards
MW	megawatt
NACAA	National Association of Clean Air Agencies
NERC	North American Electric Reliability Corporation
NO_x	nitrogen oxides
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SNCR	Selective Noncatalytic Reduction
SNL	SNL Financial
SO_2	sulfur dioxide
316(b)	Cooling Water Intake Structures regulation

U.S. GOVERNMENT ACCOUNTABILITY OFFICE
441 G St. N.W.
Washington, DC 20548

August 15, 2014

The Honorable Lisa Murkowski
Ranking Member
Committee on Energy and Natural Resources
United States Senate

Dear Senator Murkowski:

Coal is a key domestic fuel source, producing about 37 percent of the nation's electricity supply in 2012.[1] Burning coal for electricity production results in the emission of pollutants such as sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury and other metals. Coal-fueled electricity generating units are among the largest emitters of these pollutants. Using coal to generate electricity has been associated with human health and environmental concerns by the Environmental Protection Agency (EPA), the primary federal agency responsible for implementing many of the nation's environmental laws. For example, according to EPA data, SO_2 and NO_x have been linked to respiratory illnesses and acid rain.[2] In addition, coal-fueled generating units emit large quantities of carbon dioxide, the primary greenhouse gas contributing to climate change, and can use significant quantities of water and create large amounts of waste products that require disposal.

In 2012, we examined the potential impacts of key regulations on coal-fueled generating units and issued two reports.[3] In July 2012, we issued a report that examined the actions owners of power plants could take in response to several pending regulations and potential implications of

[1]Department of Energy, Energy Information Administration (EIA), *Electric Power Annual 2012* (December 2013). EIA is a statistical agency within the Department of Energy that collects, analyzes, and disseminates independent information on energy issues.

[2]SO_2 and NO_x emissions contribute to the formation of fine particulate matter, and NO_x contributes to the formation of ozone. Fine particulate matter may aggravate respiratory and cardiovascular diseases and is associated with asthma attacks and premature death. Ozone can inflame lung tissue and increase susceptibility to bronchitis and pneumonia.

[3]GAO, *EPA Regulations and Electricity: Better Monitoring by Agencies Could Strengthen Efforts to Address Potential Challenges*, GAO-12-635 (Washington, D.C.: July 17, 2012) and *Electricity: Significant Changes Are Expected in Coal-Fueled Generation, but Coal Is Likely to Remain a Key Fuel Source*, GAO-13-72 (Washington, D.C.: October 29, 2012).

these actions.[4] At that time, EPA had recently proposed or finalized four regulations, as required or authorized, that aimed to address certain health or environmental impacts associated with coal-fueled electricity generating units. These regulations included the: (1) Cross-State Air Pollution Rule (CSAPR); (2) Mercury and Air Toxics Standards (MATS); (3) Cooling Water Intake Structures regulation, which we refer to as 316(b); and (4) Disposal of Coal Combustion Residuals from Electric Utilities regulation (CCR).[5] Currently, MATS is the only one of the four regulations that has been in effect; the other regulations have been either in active litigation or have undetermined regulatory compliance periods. In July 2012,[6] we reported that it was uncertain how power companies would respond to these regulations, but that available information suggested they would retrofit some units with controls to reduce pollutants or take other steps to reduce adverse impacts.[7] We also reported that when it was not economic to take these actions—whether due to the cost of undertaking these retrofits or because of other changes that have occurred in the electric power sector, such as lower prices for natural gas—power companies may retire some units. We reported estimates that 2 to 12 percent of coal-fueled capacity could be retired, and that some regions, particularly the Midwest, could see more significant levels of retirements. These retirements could affect the amount of coal-fueled generating capacity and the amount of electricity actually generated from coal. Available information also suggested that, while these actions may not cause widespread concerns about reliability—the ability to meet the needs of consumers even when

[4]GAO-12-635.

[5]These four EPA regulations address air pollution from electricity generating units, death of aquatic life as a result of water withdrawal for use for cooling at certain electricity generating units, and disposal of coal combustion residuals from certain generating units, respectively. CSAPR limits certain emissions of air pollutants in 28 states because of the impact they would have on air quality in other states. MATS establishes emissions limitations on mercury and other toxic pollutants. The Cooling Water Intake Structures regulation (316(b)) establishes requirements for water withdrawn and used for cooling purposes that reflect the best technology available to minimize adverse environmental impact. The proposed CCR regulation would govern the disposal of coal combustion residuals, such as coal ash, in landfills or surface impoundments.

[6]GAO-12-635.

[7]Compliance with regulations may involve using various technologies or making infrastructure changes to reduce adverse impacts; for example, installing liners at facilities used to store coal combustion wastes to minimize leaching of contaminants into groundwater.

generating equipment fails unexpectedly, or other factors affect the electricity system, they may contribute to reliability challenges in some regions and these actions would likely increase electricity prices in some regions. In October 2012,[8] we also reported that two broad trends were affecting power companies' decisions related to coal-fueled generating units—recent environmental regulations and changing market conditions, such as the recent decrease in the price of natural gas. We found that power companies may build new generating units, upgrade transmission systems to maintain reliability, and increasingly use natural gas to produce electricity as coal units are retired, and remaining coal units become somewhat more expensive to operate.

Two federal agencies have responsibilities for overseeing actions power companies take in response to federal regulations and mitigating some potential adverse implications. The Federal Energy Regulatory Commission (FERC) is generally responsible for ensuring that certain electricity and transmission prices are "just and reasonable," as well as approving and enforcing standards for reliability. The Department of Energy (DOE) works to modernize the electricity system, enhance the security and reliability of the nation's energy infrastructure, and facilitate recovery from any disruptions. DOE also has authority to compel generating units to produce electricity in certain emergency situations. In our July 2012 report, we recommended that DOE, FERC, and EPA develop and document a formal, joint process consistent with each agency's respective statutory authorities to monitor industry's progress in responding to the EPA regulations until at least 2017 and that each agency, to the extent practical, leverage resources and share the results of its efforts with the other agencies. DOE and EPA agreed with this recommendation, and FERC disagreed, stating that the agencies were working to establish a more formal approach to coordination to the extent that FERC's authority allows.

You asked us to examine actions these agencies' have taken in response to our recommendation in our July 2012 report and provide updated information on planned coal-fueled generating unit retirements and retrofits. The objectives of our review were to examine: (1) DOE's, FERC's, and EPA's efforts to respond to our recommendation that the agencies develop and document a formal, joint process to monitor

[8]GAO-13-72.

industry's progress in responding to EPA regulations and (2) what is known about power companies' current plans to retire or retrofit affected coal–fueled generating units.

To address these objectives, we reviewed relevant documents and interviewed knowledgeable officials from EPA, FERC, and DOE, and other key stakeholders. We interviewed and obtained information from a sample of stakeholders who were identified and interviewed as part of our July 2012 review. Stakeholders we interviewed and obtained information from included six Regional Transmission Organizations (RTO),[9] the North American Electric Reliability Corporation (NERC),[10] and two industry groups that represent power companies. We used data from SNL Financial (SNL)[11] to provide information on historic and planned retrofits and retirements of coal-fueled generating units. Information regarding planned retrofits and retirements reflect publicly reported plans as identified by SNL. To assess the reliability of these data, we interviewed and corresponded via e-mail with knowledgeable SNL staff, analyzed the data to identify any problems with completeness and accuracy, and, where possible, corroborated the data with other available information. We determined the data were sufficiently reliable for our purposes. We also analyzed information on retirements and retrofits provided by RTOs. To assess the reliability of these data, we interviewed and corresponded

[9]Independent operators of the transmission system can be referred to as RTOs or Independent System Operators (ISO). RTOs and ISOs have similar functions, including operating the transmission system and longer-term regional planning, but ISOs tend to be smaller in geographic size or—for the ISOs in Texas and Canada—not subject to FERC jurisdiction over rates and tariffs. For the purposes of this report, we use the term RTOs to refer to both RTOs and ISOs.

[10]NERC develops and enforces reliability standards. Under the Energy Policy Act of 2005, FERC is responsible for approving and enforcing standards to ensure the reliability of the bulk power system. FERC certified NERC to develop and enforce reliability standards, subject to FERC review. These standards outline general requirements for planning and operating the bulk power system to ensure reliability. NERC annually assesses seasonal and long-term reliability.

[11]SNL's "Energy" database combines information from multiple sources including EIA, FERC, and others. Data used in this report reflect information collected through a variety of means including the EIA-860 form that collects generator-level specific information about existing and planned generators and associated environmental equipment at electric generating units. Some data are updated annually, but SNL updates others more frequently. The data we used were current in the SNL system as of May 30, 2014. As plans may change, actual future retrofits and retirements may differ from the data in these plans.

via e-mail with knowledgeable officials, analyzed the data to identify any problems with completeness and accuracy, and, where possible, corroborated the data with other available information. We determined the data we used were sufficiently reliable for our purposes.

We conducted this performance audit from May 2014 to August 2014 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Background

Because of the abundance of coal and its historically low cost, coal-fueled electricity generating units provide a large share of the electricity produced in the United States. In 2012, according to Energy Information Administration (EIA) data, there were 1,309 coal-fueled generating units in the United States,[12] with a total of 309,680 megawatts (MW) of net summer generating capacity—about 29 percent of the total net summer generating capacity in the United States.[13] In addition to coal, electricity is produced by using other fossil fuels, particularly natural gas and oil; nuclear power; and renewable sources, including hydropower, wind, geothermal, and solar. Historically, coal-fueled generating units have provided about half of the electricity produced in the United States—an amount that has declined in recent years, falling to 37 percent in 2012.

[12]EIA, *Electric Power Annual 2012* (December 2013). The number of generating units is based on information from the EIA-860 form that includes information on generating units with 1 MW or greater of combined nameplate capacity. Not all of these coal-fueled units would be subject to each of the four regulations. Additionally, noncoal electric generating units are subject to some of the regulations. Each regulation defines which units will be subject to it. For example, MATS applies to coal- and oil-fueled electricity utility steam generating units that have over 25 MW capacity and meet other requirements. We use the term electricity generating units rather than the specific regulatory definitions to refer to units subject to one or more regulations.

[13]EIA, *Electric Power Annual 2012* (December 2013). Generating capacity is measured in MW and refers to the maximum capability of a unit to produce electricity. A unit with 1,000 MW of capacity can generate up to 1,000 megawatt-hours of electricity in 1 hour, enough to provide electricity for up to 1 million homes. Net summer generating capacity refers to a generating unit's capacity to produce electricity during the summer when electricity demand for many electricity systems and losses in efficiency are generally the highest.

To address concerns over air pollution, water resources, and solid waste, several environmental laws, including the Clean Air Act, Clean Water Act, and Resource Conservation and Recovery Act, were enacted. As required or authorized by these laws, EPA recently proposed or finalized four key regulations that will affect coal-fueled units. As outlined in table 1, these regulations are at different stages of development and have different compliance deadlines.

Table 1: Major Milestones and Status of Four Key EPA Regulations that Impact Coal-Fueled Electricity Generating Units

Regulation	Date proposed	Date finalized	Compliance deadline
Cross-State Air Pollution Rule (CSAPR)	August 2010	August 2011	Deadlines have not been determined. First phase was to begin in 2012 but the rule has not taken effect because of pending litigation. On April 29, 2014, the Supreme Court reversed a ruling by the U.S. Court of Appeals for the D.C. circuit vacating CSAPR and remanded the case for further proceedings.
Mercury and Air Toxics Standards (MATS)	May 2011	February 2012[a]	April 2015 for existing generating units. Up to 1-year extension (to April 2016) for installation of controls through permitting authorities possible. Up to 1 additional year possible through Clean Air Act Administrative Order (to April 2017).
Cooling Water Intake Structures regulation (316(b))	April 2011	May 2014	Deadlines will be established on a site-specific basis by permitting authorities (generally state agencies). According to EPA officials, permitting authorities must include entrainment controls in all permits issued 45 months after the effective date of the rule (60 days after publication in the Federal Register), and will determine the compliance schedule for entrainment; facilities must comply with the impingement requirements as soon as practicable after the entrainment requirements are determined.
Disposal of Coal Combustion Residuals from Electric Utilities regulation (CCR)	June 2010	Under a consent decree, EPA was ordered by the court to finalize a regulation by December 19, 2014	Depends on which option is finalized.

Source: GAO analysis of EPA information. | GAO-14-672

Note: Proposed and finalized dates refer to when the regulations were published in the Federal Register and differ from when EPA signed the regulations except for the final 316(b) regulation, which has not been published in the Federal Register as of June 4, 2014, but was signed in May 2014.

[a]In April, 2014, a federal appellate court rejected challenges to various aspects of MATS–White Stallion Energy Center, LLC v. E.P.A., 748 F.3d 1222 (D.C. Cir. 2014)—including challenges to EPA's decision to not consider costs in determining whether regulation of mercury and other covered emissions from existing generating units is appropriate under the Clean Air Act.

These four regulations have potentially significant implications for public health and the environment. In particular, EPA projected that, among other benefits, CSAPR would reduce SO_2 emissions by 73 percent and NO_x emissions by over half in covered states, reducing asthma and related human health impacts. In addition, EPA projected that MATS would reduce mercury emissions by 75 percent from coal-fueled electricity generating units, reducing the impacts of mercury on adults and children.

In addition to these four regulations, on June 2, 2014, EPA proposed new regulations to reduce carbon dioxide emissions from existing fossil-fueled generating units that, if finalized, will impact the electricity industry, including coal-fueled generating units, aiming for overall reductions equivalent to 30 percent from 2005 emissions levels by 2030.[14] The proposed regulations include state-specific goals for carbon dioxide emissions and guidelines for states to follow in developing, submitting, and implementing plans to achieve these goals, which would be due in June 2016, although, under some circumstances, a state may submit an initial plan by June 2016 and a completed plan up to 2 years later.

In addition to DOE, FERC, and EPA, other key stakeholders have certain responsibilities for overseeing actions power companies take in response to the regulations and have a role in mitigating some potential adverse implications. These other stakeholders include state environmental and electricity regulators and system planners that coordinate planning decisions regarding transmission and generation infrastructure to maintain the reliable supply of electricity to consumers. System planners and operators attempt to avoid reliability problems through advance planning of transmission and, in some cases, generation resources, and coordinating or determining operational decisions such as which generating resources are operated to meet demand throughout the day. The role of a system planner can be carried out by individual power companies or RTOs. System planners' responsibilities include analyzing expected future changes in generation and transmission assets, such as the retirement of a generating unit; customer demand; and emerging reliability issues. For example, once a power company notifies the system

[14]The proposed regulation does not require a specific percentage reduction for each state from 2005 levels—each state has its own emission reduction target—but EPA estimates that, collectively, state targets could achieve a 30 percent overall reduction from 2005 emission levels.

planner that it is considering retiring a generating unit, the system planner generally studies the electricity system to assess whether the retirement would cause reliability challenges and identify long- or short-term solutions to mitigate any impacts. The solutions could include building new generating units, reducing demand in specific areas, building new transmission lines or adding other equipment.

DOE, EPA, and FERC Are Coordinating Efforts to Monitor Industry's Response to Key EPA Regulations in Response to GAO's Recommendation

DOE, EPA, and FERC have taken initial steps to implement the recommendation we made in our July 2012 report that these agencies develop and document a formal, joint process to monitor industry progress in responding to the four EPA regulations. Since that time, DOE, EPA, and FERC have taken initial steps collectively and individually to monitor industry progress responding to EPA regulations including jointly conducting regular meetings with key industry stakeholders. However, recent and pending actions on the four existing regulations, as well as EPA's recently proposed regulations to reduce carbon dioxide emissions from existing generating units may require additional monitoring efforts, according to DOE, EPA, and FERC officials.

DOE, EPA, and FERC Have Taken Initial Steps to Coordinate Efforts to Monitor Industry Progress

DOE, EPA, and FERC have taken initial steps to implement the recommendation we made in our July 2012 report. In that report we found the agencies had undertaken individual monitoring efforts of varied scale and scope and engaged in informal coordination, but lacked a formal documented process for routinely monitoring industry progress toward compliance with the regulations. As such, we recommended that these agencies develop and document a formal, joint process to monitor industry progress in responding to EPA regulations. We concluded that such a process was needed until at least 2017 to monitor the complexity of implementation and extent of potential effects on price and reliability. Since that time, DOE, EPA, and FERC have taken initial steps collectively to monitor industry progress responding to EPA regulations including jointly conducting regular meetings with key industry stakeholders. Currently, these monitoring efforts are primarily focused on industry implementation in regions with a large amount of capacity that must comply with the MATS regulation—the only one of the four regulations that has taken effect.

According to EPA officials, DOE, EPA, and FERC officials have met three times since our July 2012 report to coordinate the efforts under way at each agency to monitor industry's progress implementing the MATS regulation and other related issues, including EPA's development of recently proposed regulations to reduce carbon dioxide emissions from existing generating units. In addition, in May 2013, staff from DOE, EPA, and FERC jointly developed a coordination memorandum that was intended to identify how the agencies would work together to address the potential effects of EPA's regulations on reliability.[15] According to one EPA official, the memorandum was intended to be an evolving document that the agencies would revisit as appropriate, for example, as additional EPA regulations are finalized.

In addition to actions taken by the agencies to coordinate with each other, officials at DOE, EPA, and FERC told us the agencies are jointly coordinating with RTOs and other planning authorities on a regular basis to monitor industry progress toward responding to EPA regulations primarily focused on identifying potential impacts on reliability. EPA, DOE, and FERC officials told us that they do not formally analyze the information they obtain through these meetings; however, these officials told us that, based on information obtained during these meetings, they do not anticipate widespread reliability concerns. Specifically, EPA has organized regular monthly meetings with the three agencies and key stakeholders that play a role in the maintenance of the reliability of the electric power system and the implementation of relevant EPA regulations. These meetings have included outreach and education, information gathering, and technical assistance. The meetings EPA holds have included a separate monthly conference call with the three agencies and each of the four RTOs that have a large amount of generating capacity in their regions that must comply with the MATS regulation.[16] The meetings include discussion of the region's capacity and resource adequacy concerns, announced and potential retirements, air pollution

[15]According to the memorandum, the primary, though not exclusive, focus of the memorandum and of the three agencies' joint efforts is on issues related to the implementation of MATS, because MATS has been finalized and establishes specific requirements that must be achieved within well-defined time frames.

[16]These four RTOs include PJM Interconnection, which serves all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia; Midcontinent ISO, which serves parts of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, as well as the Canadian province of Manitoba; the Southwest Power Pool, which serves parts of Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas; and the Electric Reliability Council of Texas, which serves parts of Texas.

control equipment in use and retrofit plans, and other information such as reliability assessments under way in the region. As part of these meetings, officials told us that the RTOs provided information of varying levels of detail to the agencies, including information on retirement notifications and associated impacts as determined by the reliability studies completed by the RTOs; the status and findings of reliability assessments they conduct; data on the generating capacity of units with planned, announced, or completed retirements and retrofits; and data on planned outages. RTO officials told us they each gathered information about the plans for generating units in the areas they oversee. Officials from several RTOs told us that they gathered this information by surveying owners of generating units to identify, among other things, information on decisions related to retiring or retrofitting specific generating units.

According to EPA officials, the agencies' monitoring and technical assistance efforts are primarily focused on implementation of the MATS requirements because it has taken effect and includes requirements that must be achieved within well-defined time frames.[17] The MATS regulation was finalized in February 2012 and calls for a 3-year compliance period for existing generating units with the deadline of April 16, 2015, but permitting authorities may provide an extra year for certain generating units that request additional time to comply. Agency officials and stakeholders told us that state agencies are generally providing the 1-year extension for generating units—providing these units a total of 4 years to comply. In addition, according to the National Association of Clean Air Agencies (NACAA), as of May 2014, all but 9 of over 100

[17]While the proposed 316(b) rule included a requirement for compliance with the impingement mortality standards within 8 years, the final rule requires compliance schedules to be established in each individual permit. EPA officials told us that they do not have plans to undertake coordination activities with the key industry stakeholders for 316(b) similar to the activities being undertaken for MATS because some aspects of the regulation will be implemented on a site-specific basis by the permitting authorities (generally the state agencies). EPA told us that it is conducting outreach on 316(b), but in its analysis supporting the rule, EPA found that no generating units would close due to the rule, and the time frames for units to achieve compliance with the requirements are much longer than they were for MATS.

requests for extensions were granted by the state permitting agencies.[18] In addition to the MATS extension, EPA also provided a mechanism to allow certain units—generating units that are needed to address specific and documented reliability concerns—to request an additional year to come into compliance through the use of Clean Air Act administrative orders—which, if granted, would provide a total of 5 years to comply.[19] According to EPA officials, compliance with the MATS requirements has been less challenging for industry than anticipated, and operators have generally been able to undertake retrofits as part of scheduled maintenance outages; however, certain retrofits, such as the installation of a fabric filter will require additional or longer outages to be completed. According to EPA officials, whether a plant will need to schedule outages for retrofits will depend on a number of factors including the type of controls required for compliance. EPA officials told us they anticipate few administrative orders to be requested.[20] However, if EPA receives a request for an administrative order, EPA has stated in its policy that it will rely on the advice and counsel of reliability experts, including FERC, to identify and analyze reliability risks, but EPA officials will make the final decision on these requests. In May 2012, FERC issued a policy

[18]According to NACAA, the information was collected from state regulatory agencies on MATS compliance extension requests and of the 9 extensions not granted, 5 were under consideration, 2 were returned for more information, and 2 were denied. NACAA received information from 58 agencies in 45 states, D.C., and Puerto Rico; these agencies indicated that approximately six more requests may be forthcoming.

[19]EPA's Office of Enforcement and Compliance Assurance issued a policy memorandum describing its intended approach regarding the use of Clean Air Act Section 113(a) administrative orders for sources that must operate in noncompliance with MATS for up to a year to address a specific and documented reliability concern. EPA, "The Environmental Protection Agency's Enforcement Response Policy For Use of Clean Air Act Section 113(a) Administrative Orders in Relation To Electric Reliability and the Mercury and Air Toxics Standard." EPA's policy states that, to qualify for an administrative order, an owner or operator should (1) provide written notice of its compliance plans to its system planner no later than April 2014 and (2) generally no later than October 2014, submit a written request to EPA for an administrative order.

[20]EPA officials told us that the agency has not received any formal requests and that enforcement policy recommends, however, that facility operators notify planning authorities if they may need to seek an administrative order in the future. EPA told us that as of June 6, 2014, a very small number have notified planning authorities that they may ultimately request an administrative order, and EPA is monitoring these cases closely.

statement detailing how it intends to provide advice to EPA on such requests.[21]

Agencies Have Taken Individual Steps to Monitor Progress and Provide Assistance

In addition to participating in the EPA-facilitated meetings with industry and reviewing information provided from the RTOs through those meetings, DOE, FERC, and EPA have taken other steps to individually monitor or support industry progress implementing EPA regulations.

DOE. DOE is offering technical assistance to state public utility commissioners, generating unit owners and operators, and utilities on implementing the new and pending EPA regulations affecting the electric utility industry. Specifically, according to DOE officials and documents, DOE may provide technical information on cost and performance of the various retrofit control technologies; technical information on generation or transmission alternatives for any replacement power needed for retiring generating units; and assistance to public utility commissions regarding any regulatory evaluations or approvals they may have to make on utility compliance strategies. According to agency officials, while DOE offers technical assistance on implementing new and pending EPA rules, DOE has received limited requests for such assistance.

EPA. According to EPA officials, EPA has conducted outreach to ensure state agencies understand their ability to provide MATS extensions and EPA officials also review information from NACAA on the status of MATS extension requests. In addition, EPA has updated its power sector modeling tool—a model EPA uses to analyze the impact of policies, regulations, and legislative proposals on the power sector—to reflect MATS requirements along with changes in other market conditions.

FERC. FERC officials told us that they monitor information from several sources including the NERC reliability assessments,[22] EIA data on capacity additions, and information from NACAA on the status of MATS extension requests. In addition, FERC obtained industry information on

[21]FERC, "Policy Statement on the Commission's Role Regarding the Environmental Protection Agency's Mercury and Air Toxics Standards," 139 FERC ¶ 61,131, Docket No. PL12-1-000 (May 17, 2012).

[22]NERC, *2013 Long-Term Reliability Assessment*, December 2013 and *2014 Summer Reliability Assessment* (May 2014).

reliability challenges through a technical conference that it convened to obtain information on the effect of recent cold weather events on the RTOs.[23]

Recent and Pending Actions on Regulations May Require Additional Efforts to Monitor Industry's Progress

Recent and pending actions on the four existing regulations, as well as EPA's recently proposed regulations to reduce carbon dioxide emissions from existing generating units, may require additional agency effort to monitor industry's progress in responding to the regulations and any potential impacts on reliability. DOE, EPA, and FERC officials told us that, in light of these changes, their coordination efforts may need to be revisited. Specifically, one EPA official noted that the agencies may need to reexamine their coordination efforts, as appropriate, in light of changing conditions, including newly proposed EPA regulations. In addition, according to FERC officials, since not all the regulations have been finalized, conditions will continue to change, making continued monitoring of potential reliability or resource adequacy challenges important. Furthermore, in April 2014, a FERC Commissioner testified before Congress about concerns and uncertainty related to potential reliability and price impacts associated with environmental regulations.[24] Specifically, the Commissioner expressed concerns about the reliability of data on which generating units are retiring and the resources to replace those retiring generating units and called for a more formal review process including FERC, EPA, and others to analyze the specific details of retiring units, as well as the new units and new transmission that will be needed to manage the transition and ensure reliability of the nation's electricity sector.

RTO officials and other industry stakeholders also told us that recent and pending actions on regulations could have impacts on the industry's ability to reliably deliver electricity. Officials from several RTOs told us that, while widespread reliability concerns are not anticipated, some regions may face reliability challenges including challenges associated with increasing reliance on natural gas. Officials from several RTOs said that their efforts to monitor reliability impacts will include evaluating the

[23]FERC, "Technical Conference on Winter 2013-2014 Operations and Market Performance in RTOs and ISOs," AD14-8-000 (Washington, D.C.: Apr. 1, 2014).

[24]FERC, Commissioner Moeller's Testimony before the Senate Committee on Energy and Natural Resources (Washington, D.C.: Apr. 10, 2014).

recently proposed regulations to reduce carbon dioxide emissions, which may present challenges in the future. In addition, officials from one RTO told us that compliance with new and proposed EPA regulations and an evolving generation portfolio will have significant effects on the industry's ability to reliably deliver electricity. Officials from this RTO reported that their region is forecasting shortfalls in its reserve margin—additional capacity that exceeds the maximum expected demand to provide for potential backup—in some areas. In addition, these RTO officials and industry stakeholders noted that retirement of coal-fueled generating units may lead to increasing reliance on natural gas, as these generating units are replaced with natural gas fueled generating units, which will require construction of new pipeline and storage infrastructure. As a result, according to officials from one RTO, their region has increased coordination with the natural gas industry through a stakeholder forum and a series of gas infrastructure studies. These officials said that, while relying on natural gas to generate electricity has not historically negatively affected reliability, greater reliance on natural gas may require more consideration of potential fuel-related future reliability challenges.

RTO officials and other industry stakeholders also told us recent and pending actions on regulations could have impacts on electricity prices. For example, industry stakeholders told us that the retirements that are occurring or planned are significant and could lead to increased electricity rates in some regions. In addition, as we reported in July 2012, the studies we reviewed estimated that increases in electricity prices could vary across the country, with one study projecting a range of increases from 0.1 percent in the Northwest to an increase of 13.5 percent in parts of the South more dependent on electricity generated from coal. Officials from several RTOs told us that, while they analyze the potential reliability impacts of specific generating units that power companies are considering retiring, they do not analyze the potential market impacts of these retirements on electricity prices or other market factors. In addition, several RTO officials told us they cannot estimate the impacts of these potential retirements on the markets due to the number of factors involved in determining market prices and affecting markets. Based on our discussions with agency officials, FERC, DOE, and EPA are not evaluating the potential impacts of planned retirements or retrofits on electricity prices as part of their monitoring efforts. However, EPA officials told us it uses its power sector modeling tool to analyze the potential impact of new regulations on economic factors including electricity prices and has used the tool to examine the potential impact of the new carbon rule that reflected publicly announced retirements and retrofits at the time of its analysis. According to EPA's analysis for the recently proposed regulations to reduce carbon dioxide emissions from existing generating units, it projected an increase in the national average retail electricity price between 5.9% and 6.5% in 2020 compared with its base case estimate.[25]

Power Companies Plan to Retire More Generating Capacity and Retrofit Less Generating Capacity Than Initial Estimates

According to our analysis, power companies plan to retire a greater percentage of coal-fueled net summer generating capacity and retrofit less capacity with environmental controls than the estimates we reported in July 2012. Specifically, our analysis indicates that power companies retired or plan to retire about 13 percent of coal-fueled net summer generating capacity (42,192 MW) from 2012 through 2025, which exceeds the estimates of 2 to 12 percent of capacity we reported in 2012. In addition, power companies have planned or completed some type of retrofit on about 70,000 MW of net summer generating capacity to reduce SO_2, NO_x, or particulate matter from 2012 through 2025, which is less than estimates we reported in 2012. In addition to our analysis of publicly announced retirements and retrofits, RTO officials told us that power companies may take additional steps and provided information on generating units that owners may take steps to retire or retrofit; specifically, about 7,000 MW of additional capacity from 46 generating units may be retired from 2012 through 2025, beyond what we identified in our analysis of SNL data.

Power Companies Plan to Retire More Coal-Fueled Generating Capacity Than Estimated in 2012

According to our analysis of SNL data, planned retirements of coal-fueled generating units appear to have increased and are above the high end of the estimates we reported in July 2012. Specifically, power companies retired or plan to retire about 13 percent of coal-fueled net summer generating capacity (42,192 MW from 238 units) from 2012 through

[25]EPA's base case estimate—which serves as the starting point against which policy scenarios are compared—includes a projected national average retail electricity price of 10.4 cents/kilowatt-hour (kWh) in 2020. According to EPA, its base case was updated in August 2013 to reflect planned new power plant construction, retirements, new power plant cost and performance, pollution control costs and performance, emission rate assignments, state rules and enforcement actions, and other economic factors including fuel prices and demand for electricity. The base case is a projection of electricity sector activity that takes into account only those federal and state air emission laws and regulations with provisions either in effect or enacted and clearly delineated at the time the base case was finalized in August 2013.

2025.[26] When we reported in July 2012, projections suggested that 2 to 12 percent of coal-fueled capacity may be retired.[27] Based on our analysis of SNL data, power companies retired 100 coal-fueled units from January 2012 to May 2014 with a total of 14,887 MW net summer generating capacity. In addition, based on our analysis of SNL data, power companies have reported plans to retire an additional 138 coal-fueled units with a total of 27,306 MW of net summer generating capacity from June 2014 through 2025. Another recent review also identified higher projected retirements of coal-fueled capacity than estimates we reported in July 2012. Specifically, in April 2014, EIA projected that retirements from 2012 through 2020 could reach approximately 50,000 MW or about 16 percent of net summer generating capacity available at the end of 2012.[28]

Consistent with the reasons we had reported for retirements in 2012, some stakeholders we interviewed said that some of these projected retirements may have occurred without the environmental regulations. Specifically, these stakeholders noted that several industry trends may be contributing to the retirement of coal-fueled generating units, including

[26]Information on planned retirements reflects publicly reported plans for units with a net summer capacity greater than 25 MW as identified by SNL as of May 30, 2014. In total, we identified 1,080 coal-fueled electric generating units greater than 25 MW with a total net summer capacity of 319,246 MW that were operating as of January 1, 2012. The generating units we identified in SNL's database as coal-fueled generating units include units where coal is reported as the primary or secondary fuel. In addition, generating units listed as either "Out of Service" or "Mothballed" were treated as operating for the purposes of this analysis, which included about 4,200 MW of net summer generating capacity including 2,100 MW that did not have a listed retirement date. As plans may change, actual future retirements may differ from these plans. In addition, some units may be in the process of determining whether to retire, but they have not made a public announcement. Furthermore, in our review of planned retirements for existing generating units, we have identified only some services that are likely provided by these generating units. In particular, we were able to identify the net summer generating capacity, but we have not identified other services, such as ancillary services, that are important to the reliability of the electricity system. According to RTO officials, they analyze the potential reliability impacts of specific generating units that power companies are considering retiring.

[27]GAO-12-635. In addition, in October 2012 (GAO-13-72), we reported that data we examined indicated that 10 percent (30,447 MW from 174 coal-fueled units) of net summer generating capacity in service in 2011 were planned for retirement by 2020 in response to regulations and other factors.

[28]EIA, *Annual Energy Outlook 2014* (April 2014). These figures represent data produced in EIA's 2014 "Reference Case." EIA typically conducts several analyses that include variations in influential factors such as fuel prices.

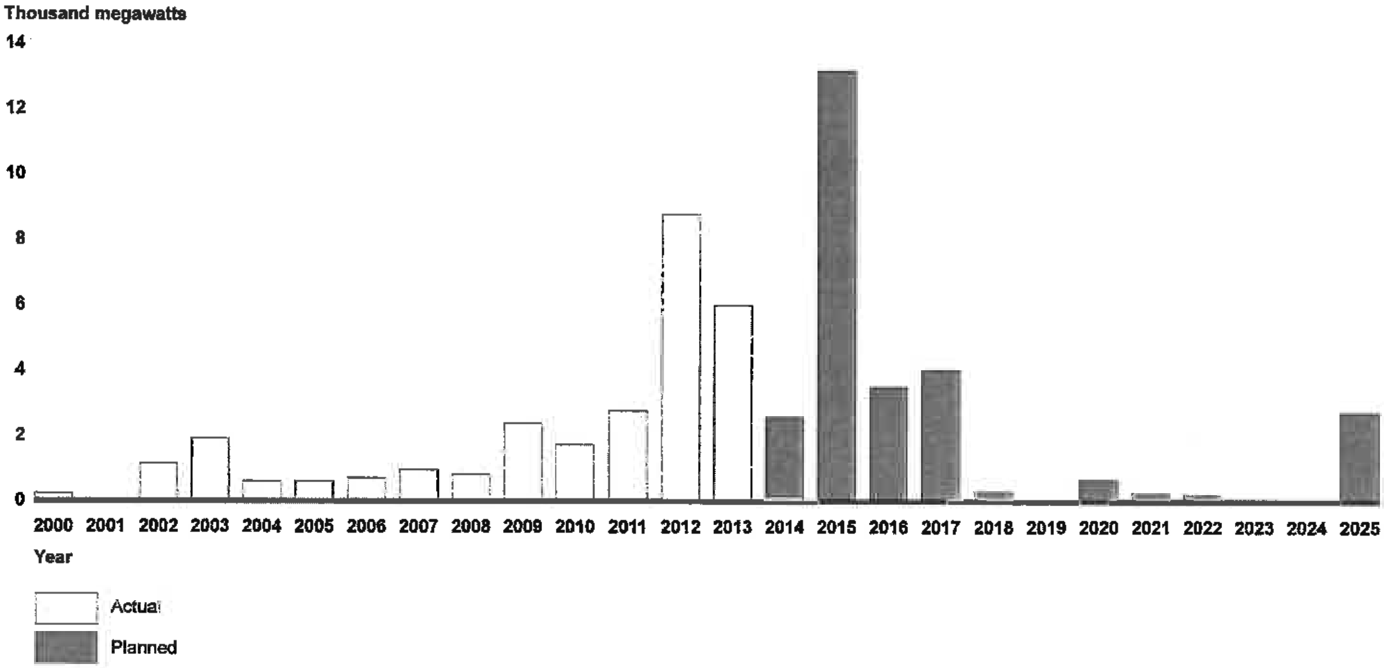
relatively low natural gas prices, increasing prices for coal, and low expected growth in demand for electricity. In addition, in June 2012, we reported that operators of some coal-fueled generating units had entered into agreements with EPA to retire or retrofit units to settle EPA enforcement actions.[29] However, we also reported in July 2012 that, according to some stakeholders, the new environmental regulations may accelerate retirements because power companies may not want to invest in retrofitting units with environmental controls for those units they expect to retire soon for other reasons.[30]

About three-quarters of the retirements we identified in our analysis of SNL data are expected to occur by the end of 2015, corresponding to the initial April 2015 MATS compliance deadline (see fig. 1). This level of retirements is significantly more retirements than have occurred in the past; for example, according to our analysis, between 2000 and 2011, 150 coal-fueled units with a total net summer generating capacity of 13,786 MW have been retired.

[29]GAO, *Air Pollution: EPA Needs Better Information on New Source Review Permits*, GAO-12-590 (Washington, D.C.: June 22, 2012). We reported that, since 1999, EPA's enforcement of New Source Review—a permitting process that applies to (1) units built after August 7, 1977, and (2) existing units that undertake a major modification—among certain coal-fired electricity generating units resulted in settlements with owners of such units. These settlements have resulted in the installation of emissions controls, unit retirements, agreements to fund environmentally beneficial projects, and tens of millions of dollars in civil penalties. In total, we reported that EPA reached 22 settlements covering 263 units, which would require affected unit owners to, among other things, install around $12.8 billion in emissions controls.

[30]GAO-12-635.

Figure 1: Net Summer Generating Capacity of Actual and Planned Retirements of Coal-Fueled Electricity Generating Units, 2000-2025



Source: GAO analysis of SNL Financial data. | GAO-14-672

Note: Data on generating unit capacity refers to units with over 25 megawatts of net summer generating capacity—a generating unit's capacity to produce electricity during the summer when electricity demand for many electricity systems and losses in efficiency are generally the highest.

According to our analysis of SNL data, the units that power companies have retired or plan to retire are generally older, smaller, and more polluting, and this is generally consistent with what we reported in October 2012.[31] In addition, we found that many of the units that companies have retired or plan to retire are those that are not used extensively and are geographically concentrated, with some exceptions. Specifically, we found the following:

- **Older.** Generating units that power companies have retired or plan to retire are generally older. The fleet of operating coal-fueled units was built over many decades, with most of the capacity currently in service

[31]GAO-13-72.

built in the 1970s and 1980s. In particular, from 2012 through 2025, power companies retired or plan to retire about 80 percent of net summer generating capacity from units that were placed in service prior to 1970 (33,419 MW from 213 of the 238 units). However, SNL data indicate that power companies retired or plan to retire some newer generating units, including one generating unit placed into service in 2008.

- **Smaller.** Generating units that power companies have retired or plan to retire are generally smaller. Smaller generating units are generally less fuel efficient than larger units and can be more expensive to retrofit, maintain, and operate on a per-MW basis. In particular, smaller units—those less that 300 MW—comprise about 63 percent of the net summer generating capacity that power companies retired or plan to retire from 2012 through 2025 (26,659 MW from 208 of the 238 units). However, some larger generating units are also planned for retirement. In particular, according to our analysis, power companies retired 4 generating units with a net summer generating capacity of over 300 MW from 1990 to 2012, and they retired or plan to retire about 30 such generating units from 2012 through 2025.
- **More polluting.** Generating units that power companies retired or plan to retire over the next 3 years emit air pollutants such as SO_2 and NO_x at generally higher rates than the remaining fleet. According to our analysis, units that were retired or are planned for retirement from 2014 through 2017 emitted on average almost three times as much SO_2 per unit of fuel used at the generating unit in 2013 as units that are not planned for retirement.[32] Similarly, units that were retired or are planned for retirement from 2014 through 2017 emitted on average about 41 percent more NO_x per unit of fuel used at the generating unit in 2013 than units not planned for retirement.[33]
- **Not used extensively.** Most generating units that power companies have retired or plan to retire have not been extensively used in recent

[32] If a power company was to retrofit a generating unit to achieve compliance with MATS this would need to occur no later than April 2017; the compliance deadline is April 2015, but extensions are possible through April 2017.

[33] This analysis considered average generating unit emissions of SO_2 and NO_x (reported as pounds per million British thermal units (Btu) of fuel used at the generating unit), fuel efficiency (reported as the "heat rate" as BTUs per kWh of output) and generation data from 2013. Data for generating units that were already retired prior to 2013 were not available. In addition, generating units that did not operate and therefore lacked data for either emissions, heat rate, or generation for all 3 years were also excluded from this analysis.

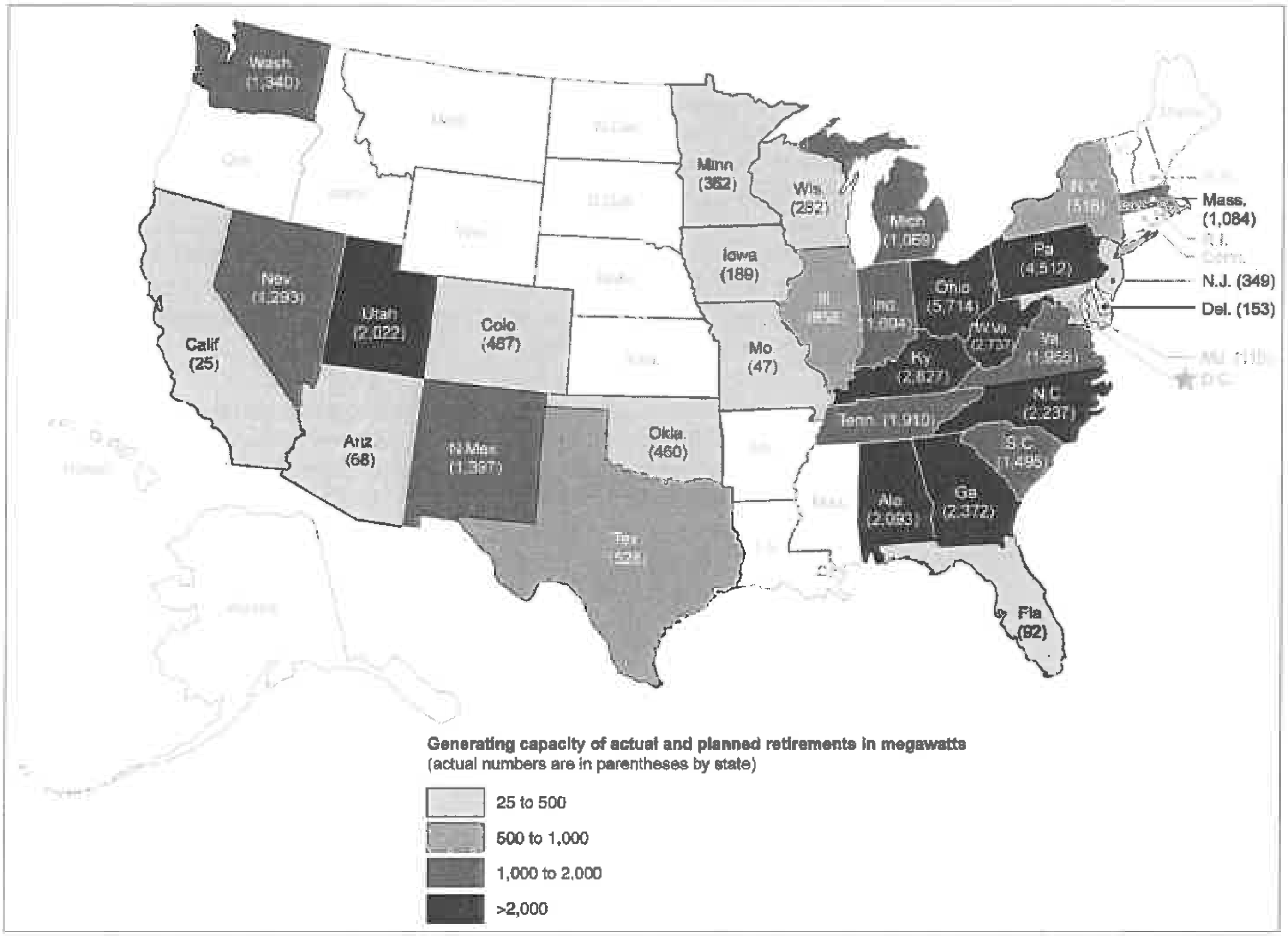
years, but other units were used more often.[34] Specifically, according to our analysis, from 2012 through 2025, power companies retired or plan to retire units that comprise about 70 percent of the net summer generating capacity (30,000 MW from 186 of the 238 units) that operated the equivalent of less than half of the hours they were available over the past few years.[35] However, data also indicate that about 13 of the 238 units that companies retired or plan to retire—which represent about 4,200 MW of net summer generating capacity—operated the equivalent of 70 percent or more of the hours they were available over the past few years.

- **Geographically concentrated.** Generating units that power companies have retired or plan to retire are concentrated in certain states (see fig. 2). Specifically, about 38 percent of the net summer generating capacity that power companies retired or plan to retire from 2012 through 2025 is located in four states—Ohio (14 percent), Pennsylvania (11 percent), Kentucky (7 percent), and West Virginia (6 percent). In particular, figure 2 shows how completed or planned retirements from 2012 through 2025 are distributed nationwide and how these are concentrated in certain areas.

[34]As noted elsewhere, this analysis only evaluated the generating output and did not evaluate other services that these units may have provided.

[35]These data reflect analysis of generating unit data on total generation (reported as "capacity factor") from 2011 through 2013. Capacity factor is a measure of how often an electric generator runs for a specific period of time. It indicates how much electricity a generator actually produces relative to the maximum it could produce at continuous full power operation during the same period. Out of the 238 units that power companies retired or plan to retire from 2012 through 2025, we did not have generation data for all 3 years for 7 units, and these units were excluded from this analysis.

Figure 2: Net Summer Generating Capacity of Actual and Planned Retirements of Coal-Fueled Electricity Generating Units by State, 2012-2025



Sources: GAO analysis of SNL Financial data; Map Resources (map). | GAO-14-672

Note: Data on generating unit capacity refers to units with over 25 megawatts of net summer generating capacity—a generating unit's capacity to produce electricity during the summer when electricity demand for many electricity systems and losses in efficiency are generally the highest.

Power Companies Plan to Retrofit Less Coal-fueled Generating Capacity Than Estimated in 2012

According to our analysis of SNL data, completed or planned retrofits of coal-fueled generating units include less capacity than estimates we reported in July 2012.[36] These retrofits include the use of a wide range of the technologies we reported at that time. As noted in our July 2012 report, operators of generating units were expected to rely on the combined installation of several technologies to comply with the regulations. These technologies include: (1) fabric filters or electrostatic precipitators to control particulate matter; (2) flue gas desulfurization units—also known as scrubbers—or dry sorbent injection units to control SO_2 and acid gas emissions; (3) selective catalytic reduction or selective noncatalytic reduction units to control NO_x; and (4) activated carbon injection units to reduce mercury emissions. Appendix I includes a description of these controls, how they operate, and their potential capacity to remove pollutants.

Our analysis of SNL data indicates that companies have identified specific units to retrofit, but the total net summer generating capacity with planned or completed retrofits from 2012 through 2025 is lower than the estimates we reported on in July 2012.[37] Most of the retrofits—about 91 percent—have occurred since 2012 or are planned for completion by the end of 2017. Specifically, according to our analysis of SNL data, power companies have planned or completed some type of retrofit on about 70,000 MW (from 153 generating units) of net summer generating capacity from 2012 through 2025.[38] More specifically, about 37,500 MW of these planned or completed retrofits involve technologies typically used to reduce emissions of NO_x, and about 41,000 MW involve technologies typically used to reduce emissions of SO_2. Data we reviewed also indicate

[36]As noted elsewhere in this report, the data we examined may change as companies make decisions about specific generating units.

[37]As noted previously, MATS has a specific and near-term deadline for compliance, but the other regulations have been either in active litigation or have undetermined regulatory compliance periods. As such, our analysis has focused on identifying steps that operators have taken to address air emissions. The data available to us provided details on installations, and planned installations, of equipment to reduce SO_2, NO_x, and particulate matter. The data did not provide details on planned installations of equipment installed specifically to reduce mercury. As noted in our 2012 reports, generating unit operators identified the use of SO_2 reduction equipment, namely scrubbers, used in conjunction with particulate controls, such as fabric filters, as a broad approach to reduce mercury.

[38]Some generating units are expecting to install more than one of these controls. As a result, total net summer generating capacity installing an environmental retrofit does not equal the sum of net summer generating capacity installing each type of retrofit.

that power companies have either installed or expect to install a scrubber—generally intended to reduce SO_2—on about 34,000 MW of net summer generating capacity from 2012 through 2025, an effort that we reported in July 2012 has typically been costly and can take some time to complete. In addition, about 20,000 MW have completed or planned to complete a retrofit to reduce particulates, including about 17,000 MW with completed or planned installations of fabric filters known as "baghouses."

By comparison, in July 2012, we reported that several studies forecasted the steps generating unit owners would take to retrofit units.[39] In particular, EPA estimated that, in response to MATS, companies would retrofit 102,000 MW of generating capacity with fabric filters and 83,000 MW with new scrubbers or scrubber upgrades.[40] In addition, a study by NERC, which collectively examined early versions of all four regulations in 2011, estimated that 576 units that account for about 234,371 MW of capacity would be retrofitted by the end of 2015.[41]

We identified two key characteristics of the units that power companies have retrofitted or plan to retrofit as follows:

- **Larger.** Most of the net summer generating capacity that have completed or plan to complete a retrofit—about 68 percent—is at larger units with capacity greater than 500 MW.
- **Geographically concentrated.** A large share of the net summer generating capacity that has completed or plan to complete a retrofit—about 36 percent—is composed of generating units located in four states: Illinois, Indiana, Kansas, and Texas. In addition, some states have completed or plan to complete more retrofits than others. In particular, seven states (Kansas, Louisiana, New Hampshire, New Mexico, Oregon, South Dakota, and Washington) have completed or plan to retrofit more than half of the net summer generating capacity located in that state.

[39]GAO-12-635.

[40]EPA projected that MATS would lead to the installation of fabric filters on 102,000 MW of capacity; upgraded electrostatic precipitators on 34,000 MW; new dry sorbent injection units on 44,000 MW; new scrubbers on 20,000 MW (and scrubber upgrades on 63,000 MW); and activated carbon injection units on 99,000 MW by 2015. EPA also projected that CSAPR will lead to retrofitted dry sorbent injection units on 3,000 MW and scrubbers on 5,900 MW by 2014.

[41]NERC, *2011 Long-Term Reliability Assessment* (November 2011).

Additional Generating Units May Take Steps to Retire or Retrofit Units According to Information Provided by RTOs

Based on information provided by RTOs, power companies may be considering retiring or retrofitting some additional generating units. In particular, RTO officials provided information on additional generating capacity that power companies have either announced plans to retire or retrofit, or are in the process of considering for a retirement or retrofit.[42] In particular, RTOs identified about 46 coal-fueled generating units that account for about 7,000 MW of additional generating capacity that may be retired from 2012 through 2025, beyond what we identified in our analysis of SNL data. In addition, RTOs identified a total of 260 units that account for about 108,000 MW of generating capacity that have completed or may undertake a retrofit from 2012 through 2025, which may include the capacity identified in our analysis.

Concluding Observations

The electricity sector is in the midst of a significant transition as power companies face decisions on the future of coal-fueled electricity generating units in light of new regulations and changes in the market, such as recent low prices for natural gas, and even though compliance deadlines for three of the regulations remain uncertain, power companies have already identified retirements beyond the range of estimates we reported in 2012. Reliable electricity remains critically important to U.S. homes and businesses and is itself reliant upon the availability of sufficient generating capacity. DOE, EPA, and FERC have taken initial steps to implement our recommendation to establish a joint process to monitor industry's progress in responding to the four EPA regulations and other factors. However, stakeholders, including a FERC Commissioner, continue to express concerns about reliability and electricity prices. Furthermore, proposed regulations focused on reducing emissions of carbon dioxide from the electricity sector, when finalized, may pose additional challenges for coal-fueled generating units. The initial coordination efforts now under way across the three agencies are an

[42]Nonpublic information on individual generating units was not provided by the RTOs; any nonpublic information related to retirements and retrofits was provided by the RTOs in aggregate. Because the data provided by the RTOs was more limited than what was available from SNL, we did not include it in our analysis above, and these retirements are in addition to the 42,192 MW of retirements reported above. However, because RTOs reported aggregated data on retrofits, and not generating unit-level data, the amounts of capacity planned for retrofits may overlap with the generating units in our analysis of SNL data. In addition, the RTOs reported the capacity figures to us in a variety of ways, some using net summer generating capacity, and others providing another measure such as nameplate capacity or did not specify. In this summary, we have aggregated the capacity figures RTOs reported to us.

important tool for understanding and monitoring the potential effects of EPA regulations and other factors on the electricity sector. However, consistent with our recommendation in 2012, careful monitoring and coordination by the federal agencies incorporating the views of other stakeholders such as RTOs will be even more important over the next several years as key regulations are finalized and implemented.

Agency Comments and Our Evaluation

We are not making new recommendations in this report. We provided a draft of this report to DOE, EPA, and FERC, for review and comment. In written comments from DOE, EPA, and FERC, reproduced in appendixes II, III, and IV respectively, the three agencies generally concurred with our analysis. The agencies stated that they will continue to monitor the progress of industry implementation of the regulations and coordinate with one another to address potential reliability challenges. Specifically, DOE stated that these coordination efforts have primarily focused on MATS and may be revisited as they work with industry to monitor compliance with other EPA regulations. EPA stated that it will monitor compliance with all of the rules, as appropriate, to ensure that reliability is not put at risk. FERC stated that it is working with industry to explore reliability issues stemming from new and pending environmental rules for the power sector, and that it will continue to monitor industry's progress implementing these rules and will coordinate with DOE, EPA, and industry. We continue to believe it is important that these agencies jointly monitor industry's progress in responding to the EPA regulations and fully document these steps as we recommended in 2012.

As agreed with your office, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies to the appropriate congressional committees, the Secretary of Energy, the Administrator of the EPA, the Chairman of FERC, and other interested parties. In addition, the report will be available at no charge on the GAO website at http://www.gao.gov.

If you or your staff members have any questions about this report, please contact me at (202) 512-3841 or ruscof@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. GAO staff members who made major contributions to this report are listed in appendix V.

Sincerely yours,

Frank Rusco

Frank Rusco
Director, Natural Resources and Environment

Appendix I: Air Pollution Control Equipment Used at Coal-Fueled Electricity Generating Units

Summary of Air Pollution Control Equipment Used at Coal-Fueled Electricity Generating Units (as reported in GAO-12-635)

Primary pollutant targeted	Equipment name	How it works	Removal efficiency
Particulate matter[a]	Electrostatic precipitator	An induced electrical charge removes particles from flue gas.	99.5%
	Fabric filter (commonly referred to as a "baghouse")	Flue gas passes through tightly woven fabric filter "bags" that filter out the particulates.	99.9%
Sulfur dioxide (SO_2)and other acid gases[b]	Flue gas desulfurization unit (commonly referred to as a "scrubber")	Wet flue gas desulfurization units inject a liquid sorbent slurry, such as a limestone slurry, into the flue gas to form a wet solid that can be disposed of or sold. Dry flue gas desulfurization units inject a dry sorbent, such as lime, into the flue gas to form a solid byproduct that is collected.	Wet scrubbers – 99% removal of SO_2 Dry scrubbers – 95% removal of SO_2
	Dry sorbent injection unit	An alkaline powdered material is injected into the flue gas (postcombustion) to react with the SO_2 and other acid gases. The resulting product is then collected through a particulate matter control device.	50% with an electrostatic precipitator, 75% with a fabric filter[c]
Nitrogen oxides (NO_x)	Combustion control technologies, such as low-NO_x burners[d]	Coal combustion conditions are adjusted so less NO_x is formed.	45% reduction in the formation of NO_x
	Postcombustion controls, such as Selective Catalytic Reduction (SCR) and Selective Noncatalytic Reduction (SNCR) units	For SCR, ammonia is injected into flue gas to react with NO_x to form nitrogen (N_2) and water and uses a catalyst to enhance the reaction. For SNCR, ammonia or urea is injected into flue gas to react with NO_x as well, but does not use a catalyst.	SCRs – 95% removal of NO_x SNCRs –75% removal of NO_x
Mercury[e]	Activated carbon injection units	Powdered activated carbon sorbent is injected into flue gas, binds with mercury, and is collected in particulate matter control device.	At least 90% with a fabric filter

Sources: GAO summary of reports by EPA, Energy Information Administration, National Academies, Electric Power Research Institute, and industry documents.

Note: Removal efficiency figures refer to the highest capacity to remove listed pollutants. Units may not always achieve these removal rates.

[a]The MATS regulation specifically places limits on "filterable" particulate matter.

[b]Another approach to reducing SO_2, mercury, and acid gas emissions from generating units is to switch from using coals with high content of these substances to coals with lower contents, or to blend coals.

[c]The removal efficiency rates presented are for SO_2. Removal efficiency rates may be higher for other acid gases.

[d]Low-NO_x burners may also be used in conjunction with postcombustion controls for NO_x.

[e]Mercury can be removed through various controls. For example, wet scrubbers also remove mercury if it is in a soluble form, and particulate matter control equipment can remove mercury that is bound to the ash.

Appendix II: Comments from the Department of Energy

Department of Energy
Washington, DC 20585

July 30, 2014

Mr. Frank Rusco
Director
Natural Resources and Environment
U.S. Government Accountability Office
Washington, D.C. 20548

Dear Director Rusco:

The Department of Energy (DOE) appreciates the opportunity to respond to the Government Accountability Office's (GAO) Draft Report, "EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements."

As noted in the report, DOE has been working with both the Environmental Protection Agency (EPA) and the Federal Energy Regulatory Commission (FERC) to monitor industry's progress in responding to the recent EPA regulations. Our three agencies have developed the coordination process referenced in the report. To date, this process has been primarily applied to industry's compliance with the Mercury and Air Toxics Standard (MATS); the process may be revisited as we work with industry to monitor compliance with other EPA regulations. We have also been meeting regularly with several independent system operators (ISOs) to monitor generator retirement and retrofit status information as well as reliability analysis updates, as described in the report. Additionally, DOE, EPA, and FERC have been meeting periodically, as needed, to coordinate efforts regarding the EPA regulations. DOE agrees that coordination between our three agencies is, and will continue to be, an important part of successfully addressing any potential reliability challenges within the electricity sector as a result of EPA's recent suite of regulations.

Additionally, DOE will continue to offer technical assistance to states and other stakeholders to help inform, rather than direct, decisions regarding implications from EPA's regulations. Technical assistance is offered through several of the DOE Offices. The report recognizes a sampling of technical assistance areas.

Finally, with respect to DOE's authority "to compel a generating unit to produce electricity in certain emergency situations" (see draft report, pg. [illegible]), DOE would like to emphasize that this emergency authority under section 202(c) of the Federal Power Act is viewed as a tool of last resort to address reliability emergencies. Should a verifiable reliability emergency arise in the future that may involve DOE's emergency authority,

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DOE will continue to coordinate with other agencies, as appropriate, to help ensure that the emergency can be resolved in accordance with other applicable statutes and regulations.

Thank you again for the opportunity to provide comment on the draft report. We look forward to receiving your final report.

Sincerely,

Patricia A. Hoffman
Assistant Secretary
Office of Electricity Delivery and Energy Reliability
U.S. Department of Energy

Appendix III: Comments from the Environmental Protection Agency

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUL 2 4 2014

OFFICE OF
AIR AND RADIATION

Mr. Frank Rusco
Director
Natural Resources and Environment
U.S. Government Accountability Office
Washington, DC 20548

Dear Mr. Rusco:

On behalf of the U.S. Environmental Protection Agency, I thank you for the continued attention of the U.S. General Accountability Office to the implementation of the EPA's power plant rules and their effect on the electricity market and the power system. These rules will have substantial public health and environmental benefits. They are achievable using technologies and practices that are widely available and that will have very little impact on electricity prices.

In 2012, GAO recommended that the EPA together with the U.S. Department of Energy and the Federal Energy Regulatory Commission further coordinate, formalize and document our activities to monitor industry's progress in implementing EPA's power plant regulations.

The past few years have been a period of significant transition for the electric power sector. The changes taking place in the electricity market, independent of EPA's rules, include a striking decline in natural gas prices, reduced demand for electricity and increased use of renewable generation in response to state standards. In addition, a majority of coal plants in the fleet have been in service for 40 years or longer. Many of these older plants are significantly less efficient than newer generation, resulting in very low utilization rates. As a result, the owners of some fossil fuel-fired power plants appear to be finding that these plants' revenues no longer cover their operating costs leading, in turn, to business decisions to retire these plants.

Of the four rules that were the subject of GAO's 2012 report, only the Mercury and Air Toxics Standards (MATS) has been in effect. Following GAO's 2012 report, the EPA, together with the U.S. Department of Energy and the Federal Energy Regulatory Commission, took steps to formalize the process that was in place to monitor the progress being made by the electric power industry to come into compliance with MATS.

We find that generators are making substantial progress in complying with MATS. MATS has put in motion planning and investment that is leading to the installation of pollution control technologies and adoption of emissions reduction measures across the existing fleet of power plants. Our communications with utilities, state regulators, regional transmission organizations and other key stakeholders indicates that these entities are proactively managing potential issues to ensure reliability is maintained and are adopting cost-effective solutions to MATS compliance requirements. Should problems arise, our ongoing communications with these parties allow us an early warning so that we can put into effect the mechanisms that are provided by the Clean Air Act to avoid a threat to reliability.

When the EPA promulgated MATS, the agency made clear several flexibilities beyond those in the rule itself that would help to assure that MATS Implementation would proceed without compromising the stability or reliability of the electric power grid. These include offering alternative forms for many of the emissions standards and allowing averaging among units at a plant rather than requiring that each unit meet the standards. The Clean Air Act allows permitting authorities (usually state environmental agencies) to grant an additional year for compliance when it is needed. The EPA reached out to state permitting authorities to assure that an additional year would be broadly available. To date, managers at over 100 generating units have asked for the additional year. In almost all cases those requests have been granted.

In addition, the EPA provided a clear pathway for units that are shown to be critical for electric reliability to obtain a schedule to achieve compliance within up to an additional year beyond the four years mentioned above. This pathway is set forth in a policy memorandum from EPA's Office of Enforcement and Compliance Assurance.[1] So far there have been no formal requests for this flexibility, but we are monitoring the potential need.

The other power sector rules that GAO considered in the 2012 report do not require as extensive an investment in as limited a timeframe as MATS required. The EPA has recently finalized the regulation on cooling water under section 316(b) of the Clean Water Act. The Cross State Air Pollution Rule is still in litigation and the Coal Combustion Residuals Rule is scheduled to become final in December. In addition the EPA has proposed a rule to limit carbon pollution from existing power plants. This rule has much flexibility in both the timing and the measures that can be used for compliance. Indeed, each state can tailor the requirements it imposes on electric generating units to suit the operational needs of its power sector. Therefore it is unlikely that there will be the same level of concern about reliability as there initially was for MATS. However, I assure you that the EPA will monitor compliance with all of these rules, as appropriate, to assure that reliability is not put at risk.

Thank you once again for your attention to this matter.

Sincerely,

Janet G. McCabe
Acting Assistant Administrator

[1] EPA Memorandum December 16, 2011. "The Environmental Protection Agency's Enforcement Response Policy For Use of Clean Air Act Section 113(a) Administrative Orders in Relation To Electric Reliability and the Mercury and Air Toxics Standard" http://www.epa.gov/compliance/resources/policies/civil/erp/mats-erp.pdf

Appendix IV: Comments from the Federal Energy Regulatory Commission

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF THE CHAIRMAN

July 16, 2014

Mr. Frank Rusco
Director
Natural Resources and Environment
United States Government Accountability Office
441 G Street, NW
Washington, D.C. 20548

Dear Mr. Rusco:

Thank you for your July 2, 2014, electronic transmission of the draft report, *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements*. I appreciate the opportunity to comment on this draft report. I agree with the draft report's observation that "reliable electricity remains critically important to U.S. homes and businesses and is itself reliant upon the availability of sufficient generating capacity."

The draft report concludes that the Federal Energy Regulatory Commission (Commission), the Department of Energy (DOE) and the Environmental Protection Agency (EPA) have taken steps to implement your recommendations to establish a joint process to monitor industry's progress in responding to four proposed or finalized EPA regulations affecting coal-fueled generating units. The draft report specifically highlights that the three agencies hold regular monthly meetings with key stakeholders that play a role in the maintenance of the reliability of the electric power system and the implementation of relevant EPA regulations, and that the Commission monitors information from several sources and has held a technical conference to obtain information on this topic. I would also like to note that the Commission and the National Association of Regulatory Utility Commissioners (NARUC) are working together to explore reliability issues stemming from new and pending environmental rules for the power sector. The FERC/ NARUC Forum on Reliability and the Environment held six meetings in plenary session at NARUC conferences. FERC and state commissioners, senior EPA officials, and industry members participated in each meeting to discuss efforts to comply with new EPA regulations (MATS, cooling water, combustion waste disposal, and 111(d)) while sustaining reliability. This effort is ongoing under the auspices of the NARUC Electricity Committee.

-2-

The draft report also concludes that continued careful monitoring and coordination by the federal agencies, incorporating the view of other stakeholders such as the RTOs, will be even more important over the next several years as the EPA regulations are implemented. I look forward to continuing to monitor the progress of industry in implementing these rules and discussing these issues with the EPA, DOE, the North American Electric Reliability Corporation, utilities, NARUC, Independent System Operators and Regional Transmission Organizations, industry, and other stakeholders.

Thank you again for the opportunity to comment on your draft report.

Sincerely,

Cheryl A. LaFleur
Acting Chairman

Appendix V: GAO Contact and Staff Acknowledgments

GAO Contact

Frank Rusco, (202) 512-3841 or ruscof@gao.gov

Staff Acknowledgments

In addition to the individual named above, Jon Ludwigson (Assistant Director), Janice Ceperich, Margaret Childs, Philip Farah, Quindi Franco, Cindy Gilbert, Richard Johnson, Armetha Liles, and Alison O'Neill made key contributions to this report.

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Washington, DC 20548

Appendix H:

EIA: Ohio Natural Gas Consumption by End User

	Data 1: Ohio Natural Gas Consumption by End Use							
	NA1490_SOH_2	NA1470_SOH_2	NA1840_SOH_2	NA1850_SOH_2	NA1480_SOH_2	N3060OH2	N3010OH2	N3020OH2
Date	Ohio Natural Gas Total Consumption (MMcf)	Ohio Natural Gas Lease and Plant Fuel Consumption (MMcf)	Ohio Natural Gas Lease Fuel Consumption (MMcf)	Ohio Natural Gas Plant Fuel Consumption (MMcf)	Ohio Natural Gas Pipeline and Distribution Use (MMcf)	Natural Gas Delivered to Consumers in Ohio (Including Vehicle Fuel) (MMcf)	Ohio Natural Gas Residential Consumption (MMcf)	Natural Gas Deliveries to Commercial Consumers (Including Vehicle Fuel through 1996) in Ohio (MMcf)
1967		2656					442360	153376
1968		3505					444964	165414
1969		2879					456414	175372
1970		3140					459972	183412
1971		4302					460820	189791
1972		3397					478331	208068
1973		3548					439212	196663
1974		2957					435800	192497
1975		2925					427817	169357
1976		2742					440190	179392
1977		2814					401928	149011
1978		3477					416721	172429
1979		22094					373631	158117
1980		1941					393759	166210
1981		1776					377134	161110
1982		3671					369437	157664
1983		4377	4327	50			329647	143568
1984		5741	5678	63			350296	155350
1985		5442	5371	71			327591	143311
1986		5243	5174	69			327300	139119
1987		5802	5706	96			326480	146983
1988		4869	4781	88			350612	158790
1989		3876	3789	87			359148	161516
1990		5129	5115	14			308321	143503
1991		1476	1462	14			321724	150339
1992		1450	1434	16			340628	160645
1993		1366	1346	20			354110	164044
1994		1332	1296	36			343331	166798
1995		1283	1251	32			357754	175160
1996		1230	1193	37			374824	189966
1997	897693	1201	1162	39	19453	877039	354543	183838
1998	811384	1125	1085	40	17641	792617	296576	156630
1999	841966		1035	42	17441	823448	318214	167573
2000	890962		986	43	18490	871444	343920	177917
2001	804243		983	40	15502	787719	308534	172555
2002	830955		972	37	16215	813735	321317	163274
2003	848388		936	17	14872	832563	343037	179611
2004	825753		894	18	12757	812084	320823	170240
2005	825961		833	12	13356	811759	322697	166693
2006	742359		855	8	12233	729264	272261	146930
2007	806350		872	5	13740	791733	299577	160580
2008	792247		840	0	11219	780187	306529	167070
2009	740925		879	0	16575	723471	292429	160612
2010	784293		773	0	15816	767704	283703	156407
2011	823548		781	0	14258	808509	286132	161408
2012	842959		836	127	9559	832437	250871	145482
2013							291198	168177

	N3035OH2	NA1570_SOH_2	N3045OH2
Date	Ohio Natural Gas Industrial Consumption (MMcf)	Ohio Natural Gas Vehicle Fuel Consumption (MMcf)	Ohio Natural Gas Deliveries to Electric Power Consumers (MMcf)
1967			
1968			
1969			
1970			
1971			
1972			
1973			
1974			
1975			
1976			
1977			
1978			
1979			
1980			
1981			
1982			
1983			
1984			
1985			
1986			
1987			
1988		0	
1989		0	
1990		73	
1991		67	
1992		59	
1993		44	
1994		48	
1995		187	
1996		229	
1997	334874	294	3491
1998	331122	309	7981
1999	325887	386	11388
2000	339060	424	10123
2001	295556	529	10545
2002	305883	539	22722
2003	290483	659	18774
2004	302023	740	18258
2005	293985	444	27941
2006	286487	403	23184
2007	293976	308	37292
2008	282834	261	23493
2009	232632	130	37668
2010	269287	146	58161
2011	268034	88	92845
2012	264405	89	171590
2013		138	160241

Appendix I:

2012 EIA-860 Data Form - Generator Data, Ohio NGCC

2012 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)																
Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Prime Mover	Status	Nameplate Capacity (MW)	Summer Capacity (MW)	Winter Capacity (MW)	Unit Code	Operating Month	Operating Year	Energy Source 1	Energy Source 2
733	Appalachian Power Co	55350	Dresden Energy Facility	OH	Muskingum	1	CT	OP	198.9	158.3	183.3		2	2012	NG	DFO
733	Appalachian Power Co	55350	Dresden Energy Facility	OH	Muskingum	2	CT	OP	198.9	158.3	183.3		2	2012	NG	DFO
733	Appalachian Power Co	55350	Dresden Energy Facility	OH	Muskingum	3	CA	OP	280.5	223.4	258.4		2	2012	NG	DFO
14006	Ohio Power Co	55503	AEP Waterford Facility	OH	Washington	CTG1	CT	OP	174.2	155.0	161.0		8	2003	NG	
14006	Ohio Power Co	55503	AEP Waterford Facility	OH	Washington	CTG2	CT	OP	174.2	155.0	161.0		8	2003	NG	
14006	Ohio Power Co	55503	AEP Waterford Facility	OH	Washington	CTG3	CT	OP	174.2	155.0	161.0		8	2003	NG	
14006	Ohio Power Co	55503	AEP Waterford Facility	OH	Washington	ST1	CA	OP	399.0	345.0	367.0		8	2003	NG	
40577	American Mun Power-Ohio, Inc	55701	Fremont Energy Center	OH	SANDUSKY	CA01	CA	OP	358.7	330.5	341.7		1	2012	NG	
40577	American Mun Power-Ohio, Inc	55701	Fremont Energy Center	OH	SANDUSKY	CT01	CT	OP	190.4	168.4	187.3		1	2012	NG	
40577	American Mun Power-Ohio, Inc	55701	Fremont Energy Center	OH	SANDUSKY	CT02	CT	OP	190.4	168.4	187.3		1	2012	NG	
57393	Duke Energy Commercial Asset Management	55397	Washington Energy Facility	OH	Washington	CT1	CT	OP	198.9	169.0	175.0		6	2002	NG	
57393	Duke Energy Commercial Asset Management	55397	Washington Energy Facility	OH	Washington	CT2	CT	OP	198.9	169.0	175.0		6	2002	NG	
57393	Duke Energy Commercial Asset Management	55397	Washington Energy Facility	OH	Washington	ST1	CA	OP	317.1	288.0	298.0		6	2002	NG	
57393	Duke Energy Commercial Asset Management	55736	Hanging Rock Energy Facility	OH	Lawrence	1GT1	CT	OP	163.5	169.0	175.0		6	2003	NG	
57393	Duke Energy Commercial Asset Management	55736	Hanging Rock Energy Facility	OH	Lawrence	1GT2	CT	OP	163.5	169.0	175.0		6	2003	NG	
57393	Duke Energy Commercial.Asset Management	55736	Hanging Rock Energy Facility	OH	Lawrence	1ST	CA	OP	317.1	288.0	298.0		6	2003	NG	
57393	Duke Energy Commercial Asset Management	55736	Hanging Rock Energy Facility	OH	Lawrence	2GT1	CT	OP	163.5	169.0	175.0		7	2003	NG	
57393	Duke Energy Commercial Asset Management	55736	Hanging Rock Energy Facility	OH	Lawrence	2GT2	CT	OP	163.5	169.0	175.0		7	2003	NG	
57393	Duke Energy Commercial Asset Management	55736	Hanging Rock Energy Facility	OH	Lawrence	2ST	CA	OP	317.1	288.0	298.0		7	2003	NG	
								TOTAL	4,342.5	3,895.3						

Appendix J:

AEP's EIA Correspondence, Dresden NGCC

Frank E Blake

From: Brian T Lysiak
Sent: Thursday, October 16, 2014 10:05 AM
To: Barrows, Matthew (CONTR)
Cc: Frank E Blake
Subject: RE: Dresden - 2012 Missing Net Generation Data (Feb through Oct)

Thanks for the update Matthew, please keep us posted.

Regards,
Brian Lysiak
Supervisor - Fuel & Contract Accounting
American Electric Power
Internal Phone: 8-220-6460
Outside Phone: 614-583-6460

From: Barrows, Matthew (CONTR) [mailto:Matthew.Barrows@eia.gov]
Sent: Thursday, October 16, 2014 9:43 AM
To: Brian T Lysiak
Subject: RE: Dresden - 2012 Missing Net Generation Data (Feb through Oct)

This is an EXTERNAL email. STOP. THINK before you CLICK links or OPEN attachments.

Good Morning, Brian –

We still haven't been able to proceed with the upload yet but I will follow up on our end and see if we can push it through. I apologize for the delay but we are focusing heavily on the 2013 Annual and Supplemental forms so hopefully we can finish the upload in the next week or so.

Thanks,
Matt

Matthew Barrows
EIA-923 Contractor
US Department of Energy
Energy Information Administration
1000 Independence Avenue, SW
Washington, DC 20585
202-586-1974

From: Brian T Lysiak [mailto:btlysiak@aep.com]
Sent: Thursday, October 16, 2014 8:12 AM
To: Barrows, Matthew (CONTR)
Cc: Frank E Blake
Subject: FW: Dresden - 2012 Missing Net Generation Data (Feb through Oct)

Hi Matthew -
We still don't see the revised 2012 data out there for Dresden. Has it been uploaded?

Regards,
Brian Lysiak
Supervisor - Fuel & Contract Accounting
American Electric Power
Internal Phone: 8-220-6460
Outside Phone: 614-583-6460

From: Barrows, Matthew (CONTR) [mailto:Matthew.Barrows@eia.gov]
Sent: Wednesday, September 03, 2014 9:39 AM
To: Brian T Lysiak
Subject: RE: Dresden - 2012 Missing Net Generation Data (Feb through Oct)

This is an EXTERNAL email. STOP. THINK before you CLICK links or OPEN attachments.

Good Morning, Brian –

We haven't been able to upload the data yet as we just received the go ahead yesterday. At the earliest, we're looking at next week for the upload since we're currently in the process of delivering 2014 July data.

Thanks,

Matthew Barrows
EIA-923 Contractor
US Department of Energy
Energy Information Administration
1000 Independence Avenue, SW
Washington, DC 20585
202-586-1974

From: Brian T Lysiak [mailto:btlysiak@aep.com]
Sent: Wednesday, September 03, 2014 7:46 AM
To: Barrows, Matthew (CONTR)
Cc: Frank E Blake
Subject: RE: Dresden - 2012 Missing Net Generation Data (Feb through Oct)

Hi Matt
Do you have a progress status to get Dresden 2012 data updated on the EIA 923?

Regards,
Brian Lysiak
Supervisor - Fuel & Contract Accounting
American Electric Power
Internal Phone: 8-220-6460
Outside Phone: 614-583-6460

From: Brian T Lysiak
Sent: Wednesday, August 27, 2014 4:41 PM
To: Matthew.Barrows@eia.gov
Subject: FW: Dresden - 2012 Missing Net Generation Data (Feb through Oct)

Regards,
Brian Lysiak
Supervisor - Fuel & Contract Accounting
American Electric Power
Internal Phone: 8-220-6460
Outside Phone: 614-583-6460

From: Brian T Lysiak
Sent: Wednesday, August 27, 2014 2:48 PM
To: 'Barrows, Matthew (CONTR)'
Cc: Frank E Blake; Murny Chung
Subject: RE: Dresden - 2012 Missing Net Generation Data (Feb through Oct)

Hi Matt
Here is the Feb 2012 file with Dresden Only on the import tabs.
We are on a tight schedule for needing to get this information updated, as the incorrect EIA data is being referenced for various environmental related determinations that impact AEP.

I will proceed with sending remaining months by the end of today.
Please advise of any delays/issues as soon as encountered so we can keep on track for the fastest turn around.
Thanks.

Regards,
Brian Lysiak
Supervisor - Fuel & Contract Accounting
American Electric Power
Internal Phone: 8-220-6460
Outside Phone: 614-583-6460

From: Barrows, Matthew (CONTR) [mailto:Matthew.Barrows@eia.gov]
Sent: Wednesday, August 27, 2014 10:39 AM
To: Brian T Lysiak
Cc: Frank E Blake; Murny Chung
Subject: RE: Dresden - 2012 Missing Net Generation Data (Feb through Oct)

This is an EXTERNAL email. STOP. THINK before you CLICK links or OPEN attachments.

Good Morning, Brian –

My apologies for the delay, but it looks like we didn't start receiving data from AEP for Dresden until November 2012. Can you confirm the commercial operation date for February 2012? If there is data starting at that time we would open those surveys, Monthly and Supplemental, for you to submit/revise.

Thanks,
Matt

Matthew Barrows
EIA-923 Contractor
US Department of Energy
Energy Information Administration
1000 Independence Avenue, SW
Washington, DC 20585

202-586-1974

From: Brian T Lysiak
Sent: Monday, August 25, 2014 7:04 AM
To: 'Barrows, Matthew (CONTR)'
Cc: Frank E Blake; Murny Chung
Subject: RE: Dresden - 2012 Missing Net Generation Data (Feb through Oct)

Hi Matt-
Please let us know of any findings you determine on the missing Dresden data, as soon as you can. Thanks.

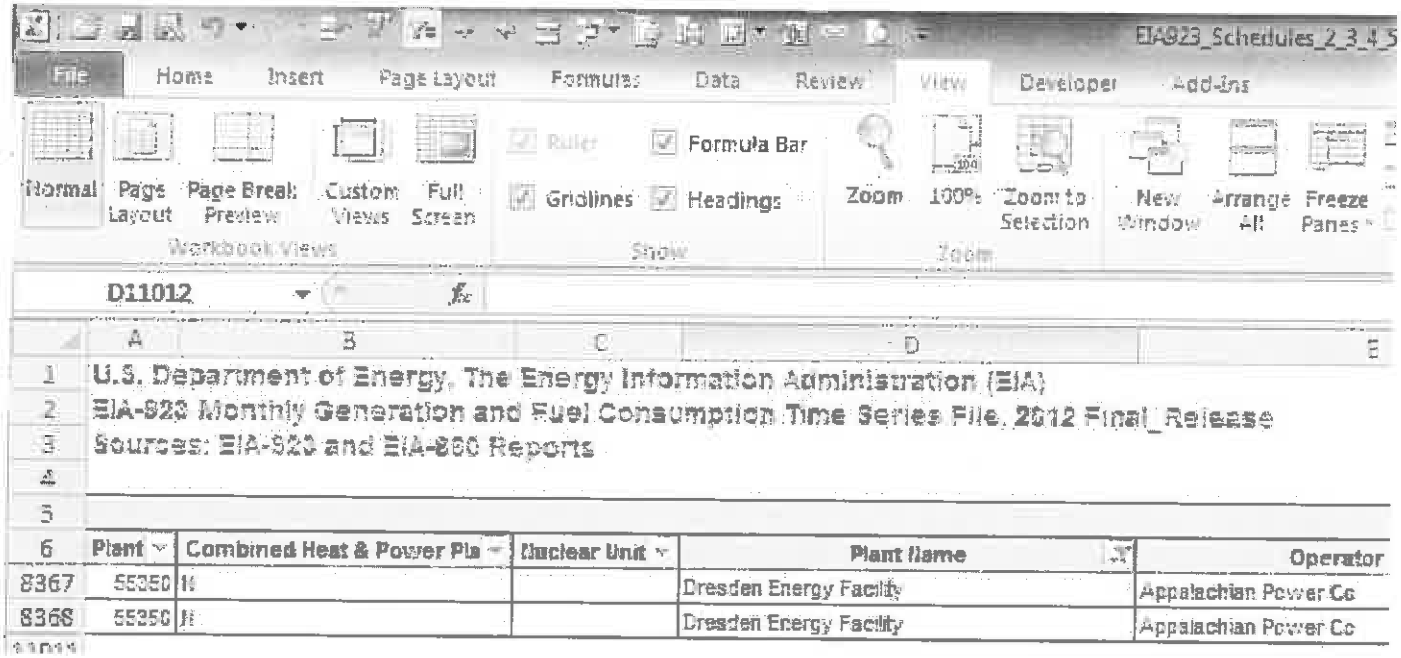
Regards,
Brian Lysiak
Supervisor - Fuel & Contract Accounting
American Electric Power
Internal Phone: 8-220-6460
Outside Phone: 614-583-6460

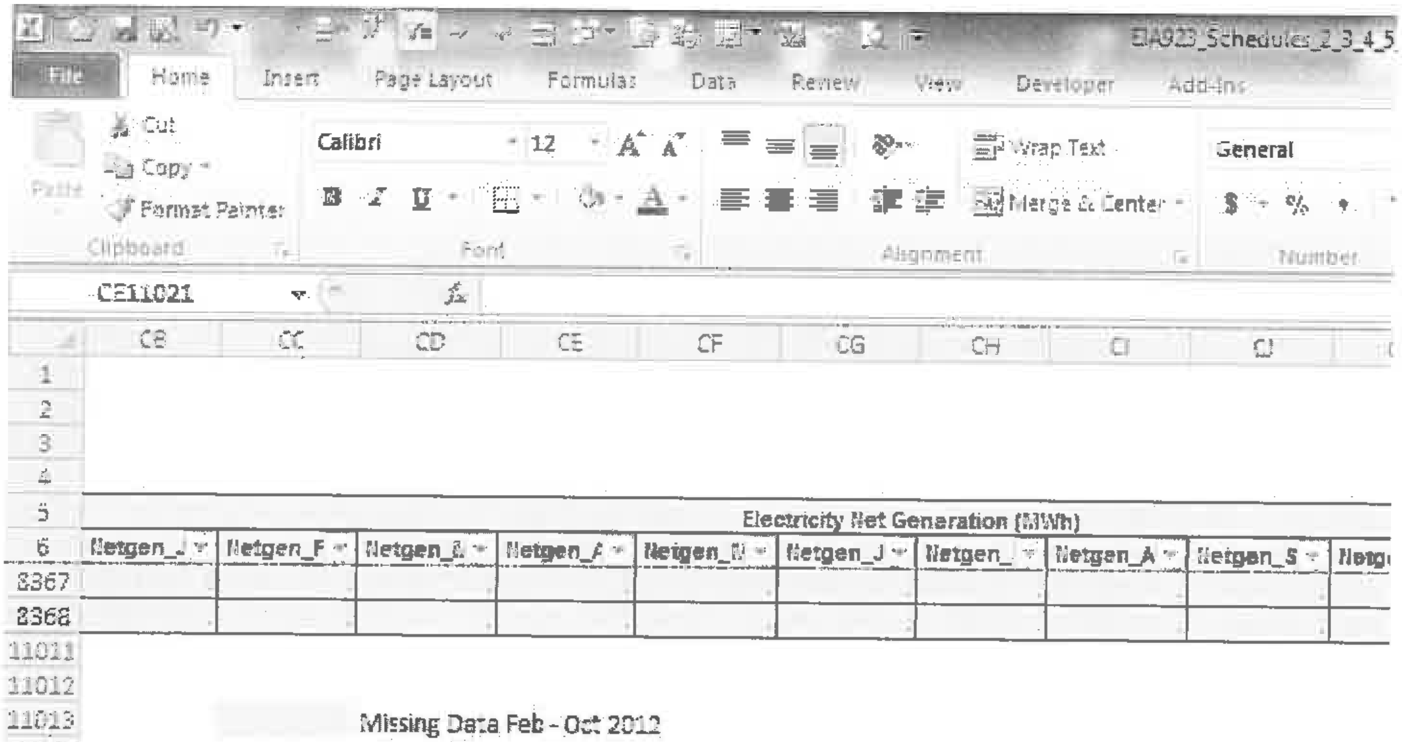
From: Brian T Lysiak
Sent: Thursday, August 21, 2014 8:28 AM
To: 'Barrows, Matthew (CONTR)'
Cc: Frank E Blake; Murny Chung
Subject: Dresden - 2012 Missing Net Generation Data (Feb through Oct)

Hi Matt-
When we pull down the EIA923_Schedules_2_3_4_5_2012_Final_Release_12.04.2013.xlsx and filter on (Page 1 Generation and Fuel Data) the entire year only has data for Nov & Dec.

Dresden should have amounts starting in Feb 2012.
I pulled our sources files that would have been sent for import and they has values for Feb-Oct. Is there a reason these are not being populated within the summary?

Thanks.





Regards,
Brian Lysiak
Supervisor - Fuel & Contract Accounting
American Electric Power
Internal Phone: 8-220-6460
Outside Phone: 614-583-6460

Appendix K:

EIA Annual Net Generation: 1990-2012

Net Generation by State, Type of Producer and Energy Source

State Historical Tables for 2012 Released: December 2013 Next Update: November 2014				
YEAR	**STATE**	**TYPE OF PRODUCER**	**ENERGY SOURCE**	**GENERATION (Megawatthours)**
1990	OH	Total Electric Power Industry	Total	127,980,527
1990	OH	Total Electric Power Industry	Coal	115,832,650
1990	OH	Total Electric Power Industry	Hydroelectric Conventional	181,395
1990	OH	Total Electric Power Industry	Natural Gas	241,585
1990	OH	Total Electric Power Industry	Nuclear	10,663,897
1990	OH	Total Electric Power Industry	Other Biomass	304,285
1990	OH	Total Electric Power Industry	Other Gases	64,159
1990	OH	Total Electric Power Industry	Petroleum	374,481
1990	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	318,075
1990	OH	Electric Generators, Independent Power Producers	Total	8,813
1990	OH	Electric Generators, Independent Power Producers	Hydroelectric Conventional	8,813
1990	OH	Electric Generators, Electric Utilities	Total	126,509,829
1990	OH	Electric Generators, Electric Utilities	Coal	115,014,081
1990	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	172,582
1990	OH	Electric Generators, Electric Utilities	Natural Gas	91,191
1990	OH	Electric Generators, Electric Utilities	Nuclear	10,663,897
1990	OH	Electric Generators, Electric Utilities	Other Biomass	266,834
1990	OH	Electric Generators, Electric Utilities	Petroleum	301,244
1990	OH	Combined Heat and Power, Industrial Power	Total	1,342,799
1990	OH	Combined Heat and Power, Industrial Power	Coal	816,349
1990	OH	Combined Heat and Power, Industrial Power	Natural Gas	80,413
1990	OH	Combined Heat and Power, Industrial Power	Other Gases	64,159
1990	OH	Combined Heat and Power, Industrial Power	Petroleum	63,803
1990	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	318,075
1990	OH	Combined Heat and Power, Electric Power	Total	32,016
1990	OH	Combined Heat and Power, Electric Power	Other Biomass	32,016
1990	OH	Combined Heat and Power, Commercial Power	Total	87,070
1990	OH	Combined Heat and Power, Commercial Power	Coal	2,220
1990	OH	Combined Heat and Power, Commercial Power	Natural Gas	69,981
1990	OH	Combined Heat and Power, Commercial Power	Other Biomass	5,435
1990	OH	Combined Heat and Power, Commercial Power	Petroleum	9,434
1990	OH	Combined Heat and Power, Commercial Power	Wood and Wood Derived Fuels	0
1991	OH	Total Electric Power Industry	Total	134,036,497
1991	OH	Total Electric Power Industry	Coal	117,502,355
1991	OH	Total Electric Power Industry	Hydroelectric Conventional	154,224
1991	OH	Total Electric Power Industry	Natural Gas	364,566
1991	OH	Total Electric Power Industry	Nuclear	14,832,789
1991	OH	Total Electric Power Industry	Other Biomass	324,478
1991	OH	Total Electric Power Industry	Other Gases	57,312
1991	OH	Total Electric Power Industry	Petroleum	427,742
1991	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	373,031
1991	OH	Electric Generators, Independent Power Producers	Total	8,813
1991	OH	Electric Generators, Independent Power Producers	Hydroelectric Conventional	8,813
1991	OH	Electric Generators, Electric Utilities	Total	132,693,706
1991	OH	Electric Generators, Electric Utilities	Coal	116,813,173
1991	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	145,411
1991	OH	Electric Generators, Electric Utilities	Natural Gas	234,956
1991	OH	Electric Generators, Electric Utilities	Nuclear	14,832,789
1991	OH	Electric Generators, Electric Utilities	Other Biomass	298,016
1991	OH	Electric Generators, Electric Utilities	Petroleum	369,361
1991	OH	Combined Heat and Power, Industrial Power	Total	1,238,522
1991	OH	Combined Heat and Power, Industrial Power	Coal	687,452
1991	OH	Combined Heat and Power, Industrial Power	Natural Gas	68,046
1991	OH	Combined Heat and Power, Industrial Power	Other Gases	57,312
1991	OH	Combined Heat and Power, Industrial Power	Petroleum	52,681
1991	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	373,031
1991	OH	Combined Heat and Power, Electric Power	Total	26,462
1991	OH	Combined Heat and Power, Electric Power	Other Biomass	26,462
1991	OH	Combined Heat and Power, Commercial Power	Total	68,994
1991	OH	Combined Heat and Power, Commercial Power	Coal	1,730

Net Generation by State, Type of Producer and Energy Source

YEAR	STATE	TYPE OF PRODUCER	ENERGY SOURCE	GENERATION (Megawatthours)
1991	OH	Combined Heat and Power, Commercial Power	Natural Gas	61,564
1991	OH	Combined Heat and Power, Commercial Power	Petroleum	5,700
1992	OH	Total Electric Power Industry	Total	137,661,728
1992	OH	Total Electric Power Industry	Coal	121,249,946
1992	OH	Total Electric Power Industry	Hydroelectric Conventional	253,165
1992	OH	Total Electric Power Industry	Natural Gas	340,236
1992	OH	Total Electric Power Industry	Nuclear	14,805,499
1992	OH	Total Electric Power Industry	Other Biomass	349,113
1992	OH	Total Electric Power Industry	Other Gases	73,545
1992	OH	Total Electric Power Industry	Petroleum	258,124
1992	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	332,100
1992	OH	Electric Generators, Independent Power Producers	Total	8,813
1992	OH	Electric Generators, Independent Power Producers	Hydroelectric Conventional	8,813
1992	OH	Electric Generators, Electric Utilities	Total	136,296,552
1992	OH	Electric Generators, Electric Utilities	Coal	120,529,191
1992	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	244,352
1992	OH	Electric Generators, Electric Utilities	Natural Gas	212,669
1992	OH	Electric Generators, Electric Utilities	Nuclear	14,805,499
1992	OH	Electric Generators, Electric Utilities	Other Biomass	309,613
1992	OH	Electric Generators, Electric Utilities	Petroleum	195,228
1992	OH	Combined Heat and Power, Industrial Power	Total	1,248,825
1992	OH	Combined Heat and Power, Industrial Power	Coal	720,135
1992	OH	Combined Heat and Power, Industrial Power	Natural Gas	66,797
1992	OH	Combined Heat and Power, Industrial Power	Other Gases	73,545
1992	OH	Combined Heat and Power, Industrial Power	Petroleum	56,248
1992	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	332,100
1992	OH	Combined Heat and Power, Electric Power	Total	32,738
1992	OH	Combined Heat and Power, Electric Power	Other Biomass	32,738
1992	OH	Combined Heat and Power, Commercial Power	Total	74,800
1992	OH	Combined Heat and Power, Commercial Power	Coal	620
1992	OH	Combined Heat and Power, Commercial Power	Natural Gas	60,770
1992	OH	Combined Heat and Power, Commercial Power	Other Biomass	6,762
1992	OH	Combined Heat and Power, Commercial Power	Petroleum	6,648
1993	OH	Total Electric Power Industry	Total	135,237,292
1993	OH	Total Electric Power Industry	Coal	123,795,912
1993	OH	Total Electric Power Industry	Hydroelectric Conventional	189,613
1993	OH	Total Electric Power Industry	Natural Gas	371,452
1993	OH	Total Electric Power Industry	Nuclear	10,010,661
1993	OH	Total Electric Power Industry	Other Biomass	99,045
1993	OH	Total Electric Power Industry	Other Gases	128,520
1993	OH	Total Electric Power Industry	Petroleum	346,002
1993	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	296,087
1993	OH	Electric Generators, Independent Power Producers	Total	6,544
1993	OH	Electric Generators, Independent Power Producers	Hydroelectric Conventional	6,544
1993	OH	Electric Generators, Electric Utilities	Total	133,735,428
1993	OH	Electric Generators, Electric Utilities	Coal	123,024,655
1993	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	183,069
1993	OH	Electric Generators, Electric Utilities	Natural Gas	176,872
1993	OH	Electric Generators, Electric Utilities	Nuclear	10,010,661
1993	OH	Electric Generators, Electric Utilities	Other Biomass	64,134
1993	OH	Electric Generators, Electric Utilities	Petroleum	276,037
1993	OH	Combined Heat and Power, Industrial Power	Total	1,405,005
1993	OH	Combined Heat and Power, Industrial Power	Coal	771,257
1993	OH	Combined Heat and Power, Industrial Power	Natural Gas	145,446
1993	OH	Combined Heat and Power, Industrial Power	Other Gases	128,520
1993	OH	Combined Heat and Power, Industrial Power	Petroleum	63,695
1993	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	296,087
1993	OH	Combined Heat and Power, Electric Power	Total	26,093
1993	OH	Combined Heat and Power, Electric Power	Other Biomass	26,093
1993	OH	Combined Heat and Power, Commercial Power	Total	64,222
1993	OH	Combined Heat and Power, Commercial Power	Coal	0
1993	OH	Combined Heat and Power, Commercial Power	Natural Gas	49,134
1993	OH	Combined Heat and Power, Commercial Power	Other Biomass	8,818
1993	OH	Combined Heat and Power, Commercial Power	Petroleum	6,270

Net Generation by State, Type of Producer and Energy Source

YEAR	STATE	TYPE OF PRODUCER	ENERGY SOURCE	GENERATION (Megawatthours)
1994	OH	Total Electric Power Industry	Total	131,763,610
1994	OH	Total Electric Power Industry	Coal	119,169,558
1994	OH	Total Electric Power Industry	Hydroelectric Conventional	191,771
1994	OH	Total Electric Power Industry	Natural Gas	371,591
1994	OH	Total Electric Power Industry	Nuclear	10,952,247
1994	OH	Total Electric Power Industry	Other Biomass	28,830
1994	OH	Total Electric Power Industry	Other Gases	144,300
1994	OH	Total Electric Power Industry	Petroleum	424,488
1994	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	480,825
1994	OH	Electric Generators, Independent Power Producers	Total	2,950
1994	OH	Electric Generators, Independent Power Producers	Hydroelectric Conventional	2,950
1994	OH	Electric Generators, Electric Utilities	Total	129,020,582
1994	OH	Electric Generators, Electric Utilities	Coal	117,354,244
1994	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	188,821
1994	OH	Electric Generators, Electric Utilities	Natural Gas	152,957
1994	OH	Electric Generators, Electric Utilities	Nuclear	10,952,247
1994	OH	Electric Generators, Electric Utilities	Other Biomass	0
1994	OH	Electric Generators, Electric Utilities	Petroleum	372,313
1994	OH	Combined Heat and Power, Industrial Power	Total	1,379,118
1994	OH	Combined Heat and Power, Industrial Power	Coal	551,404
1994	OH	Combined Heat and Power, Industrial Power	Natural Gas	155,208
1994	OH	Combined Heat and Power, Industrial Power	Other Gases	144,300
1994	OH	Combined Heat and Power, Industrial Power	Petroleum	47,381
1994	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	480,825
1994	OH	Combined Heat and Power, Electric Power	Total	1,304,995
1994	OH	Combined Heat and Power, Electric Power	Coal	1,263,743
1994	OH	Combined Heat and Power, Electric Power	Natural Gas	20,882
1994	OH	Combined Heat and Power, Electric Power	Other Biomass	20,370
1994	OH	Combined Heat and Power, Commercial Power	Total	55,965
1994	OH	Combined Heat and Power, Commercial Power	Coal	167
1994	OH	Combined Heat and Power, Commercial Power	Natural Gas	42,544
1994	OH	Combined Heat and Power, Commercial Power	Other Biomass	8,460
1994	OH	Combined Heat and Power, Commercial Power	Petroleum	4,794
1995	OH	Total Electric Power Industry	Total	139,343,902
1995	OH	Total Electric Power Industry	Coal	120,629,428
1995	OH	Total Electric Power Industry	Hydroelectric Conventional	232,221
1995	OH	Total Electric Power Industry	Natural Gas	724,821
1995	OH	Total Electric Power Industry	Nuclear	16,768,050
1995	OH	Total Electric Power Industry	Other Biomass	21,860
1995	OH	Total Electric Power Industry	Other Gases	139,069
1995	OH	Total Electric Power Industry	Petroleum	330,064
1995	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	498,389
1995	OH	Electric Generators, Independent Power Producers	Total	4,762
1995	OH	Electric Generators, Independent Power Producers	Hydroelectric Conventional	4,762
1995	OH	Electric Generators, Electric Utilities	Total	137,860,132
1995	OH	Electric Generators, Electric Utilities	Coal	120,043,024
1995	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	227,459
1995	OH	Electric Generators, Electric Utilities	Natural Gas	523,480
1995	OH	Electric Generators, Electric Utilities	Nuclear	16,768,050
1995	OH	Electric Generators, Electric Utilities	Other Biomass	0
1995	OH	Electric Generators, Electric Utilities	Petroleum	298,119
1995	OH	Combined Heat and Power, Industrial Power	Total	1,425,403
1995	OH	Combined Heat and Power, Industrial Power	Coal	585,014
1995	OH	Combined Heat and Power, Industrial Power	Natural Gas	173,912
1995	OH	Combined Heat and Power, Industrial Power	Other Gases	139,069
1995	OH	Combined Heat and Power, Industrial Power	Petroleum	29,019
1995	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	498,389
1995	OH	Combined Heat and Power, Electric Power	Total	19,979
1995	OH	Combined Heat and Power, Electric Power	Other Biomass	19,979
1995	OH	Combined Heat and Power, Commercial Power	Total	33,626
1995	OH	Combined Heat and Power, Commercial Power	Coal	1,390
1995	OH	Combined Heat and Power, Commercial Power	Natural Gas	27,429
1995	OH	Combined Heat and Power, Commercial Power	Other Biomass	1,881
1995	OH	Combined Heat and Power, Commercial Power	Petroleum	2,926

Net Generation by State, Type of Producer and Energy Source

YEAR	STATE	TYPE OF PRODUCER	ENERGY SOURCE	GENERATION (Megawatthours)
1996	OH	Total Electric Power Industry	Total	144,437,214
1996	OH	Total Electric Power Industry	Coal	128,640,943
1996	OH	Total Electric Power Industry	Hydroelectric Conventional	397,354
1996	OH	Total Electric Power Industry	Natural Gas	410,269
1996	OH	Total Electric Power Industry	Nuclear	13,919,390
1996	OH	Total Electric Power Industry	Other Biomass	5,829
1996	OH	Total Electric Power Industry	Other Gases	176,515
1996	OH	Total Electric Power Industry	Petroleum	303,872
1996	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	583,042
1996	OH	Electric Generators, Independent Power Producers	Total	4,880
1996	OH	Electric Generators, Independent Power Producers	Hydroelectric Conventional	4,880
1996	OH	Electric Generators, Electric Utilities	Total	142,900,353
1996	OH	Electric Generators, Electric Utilities	Coal	128,125,332
1996	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	392,474
1996	OH	Electric Generators, Electric Utilities	Natural Gas	195,917
1996	OH	Electric Generators, Electric Utilities	Nuclear	13,919,390
1996	OH	Electric Generators, Electric Utilities	Other Biomass	0
1996	OH	Electric Generators, Electric Utilities	Petroleum	267,240
1996	OH	Combined Heat and Power, Industrial Power	Total	1,437,370
1996	OH	Combined Heat and Power, Industrial Power	Coal	512,923
1996	OH	Combined Heat and Power, Industrial Power	Natural Gas	175,505
1996	OH	Combined Heat and Power, Industrial Power	Other Gases	176,515
1996	OH	Combined Heat and Power, Industrial Power	Petroleum	32,364
1996	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	540,063
1996	OH	Combined Heat and Power, Electric Power	Total	48,770
1996	OH	Combined Heat and Power, Electric Power	Natural Gas	335
1996	OH	Combined Heat and Power, Electric Power	Other Biomass	5,829
1996	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	42,606
1996	OH	Combined Heat and Power, Commercial Power	Total	45,841
1996	OH	Combined Heat and Power, Commercial Power	Coal	2,688
1996	OH	Combined Heat and Power, Commercial Power	Natural Gas	38,512
1996	OH	Combined Heat and Power, Commercial Power	Petroleum	4,268
1996	OH	Combined Heat and Power, Commercial Power	Wood and Wood Derived Fuels	373
1997	OH	Total Electric Power Industry	Total	142,811,248
1997	OH	Total Electric Power Industry	Coal	125,435,419
1997	OH	Total Electric Power Industry	Hydroelectric Conventional	507,368
1997	OH	Total Electric Power Industry	Natural Gas	468,934
1997	OH	Total Electric Power Industry	Nuclear	15,330,830
1997	OH	Total Electric Power Industry	Other Biomass	94
1997	OH	Total Electric Power Industry	Other Gases	189,767
1997	OH	Total Electric Power Industry	Petroleum	293,908
1997	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	584,928
1997	OH	Electric Generators, Electric Utilities	Total	141,248,874
1997	OH	Electric Generators, Electric Utilities	Coal	124,909,642
1997	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	507,368
1997	OH	Electric Generators, Electric Utilities	Natural Gas	228,254
1997	OH	Electric Generators, Electric Utilities	Nuclear	15,330,830
1997	OH	Electric Generators, Electric Utilities	Other Biomass	0
1997	OH	Electric Generators, Electric Utilities	Petroleum	272,780
1997	OH	Combined Heat and Power, Industrial Power	Total	1,464,989
1997	OH	Combined Heat and Power, Industrial Power	Coal	522,498
1997	OH	Combined Heat and Power, Industrial Power	Natural Gas	197,093
1997	OH	Combined Heat and Power, Industrial Power	Other Biomass	94
1997	OH	Combined Heat and Power, Industrial Power	Other Gases	189,767
1997	OH	Combined Heat and Power, Industrial Power	Petroleum	16,624
1997	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	538,913
1997	OH	Combined Heat and Power, Electric Power	Total	44,111
1997	OH	Combined Heat and Power, Electric Power	Natural Gas	301
1997	OH	Combined Heat and Power, Electric Power	Other Biomass	0
1997	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	43,810
1997	OH	Combined Heat and Power, Commercial Power	Total	53,274
1997	OH	Combined Heat and Power, Commercial Power	Coal	3,279
1997	OH	Combined Heat and Power, Commercial Power	Natural Gas	43,286
1997	OH	Combined Heat and Power, Commercial Power	Petroleum	4,504

Net Generation by State, Type of Producer and Energy Source

YEAR	STATE	TYPE OF PRODUCER	ENERGY SOURCE	GENERATION (Megawatthours)
1997	OH	Combined Heat and Power, Commercial Power	Wood and Wood Derived Fuels	2,205
1998	OH	Total Electric Power Industry	Total	147,940,057
1998	OH	Total Electric Power Industry	Coal	129,223,181
1998	OH	Total Electric Power Industry	Hydroelectric Conventional	406,427
1998	OH	Total Electric Power Industry	Natural Gas	677,578
1998	OH	Total Electric Power Industry	Nuclear	16,475,732
1998	OH	Total Electric Power Industry	Other Biomass	241
1998	OH	Total Electric Power Industry	Other Gases	185,762
1998	OH	Total Electric Power Industry	Petroleum	370,838
1998	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	600,298
1998	OH	Electric Generators, Electric Utilities	Total	146,448,159
1998	OH	Electric Generators, Electric Utilities	Coal	128,696,073
1998	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	406,427
1998	OH	Electric Generators, Electric Utilities	Natural Gas	518,519
1998	OH	Electric Generators, Electric Utilities	Nuclear	16,475,732
1998	OH	Electric Generators, Electric Utilities	Other Biomass	0
1998	OH	Electric Generators, Electric Utilities	Petroleum	351,408
1998	OH	Combined Heat and Power, Industrial Power	Total	1,285,770
1998	OH	Combined Heat and Power, Industrial Power	Coal	422,251
1998	OH	Combined Heat and Power, Industrial Power	Natural Gas	107,256
1998	OH	Combined Heat and Power, Industrial Power	Other Biomass	241
1998	OH	Combined Heat and Power, Industrial Power	Other Gases	185,762
1998	OH	Combined Heat and Power, Industrial Power	Petroleum	13,599
1998	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	556,661
1998	OH	Combined Heat and Power, Electric Power	Total	155,195
1998	OH	Combined Heat and Power, Electric Power	Coal	102,682
1998	OH	Combined Heat and Power, Electric Power	Natural Gas	8,683
1998	OH	Combined Heat and Power, Electric Power	Other Biomass	0
1998	OH	Combined Heat and Power, Electric Power	Petroleum	1,920
1998	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	41,910
1998	OH	Combined Heat and Power, Commercial Power	Total	50,933
1998	OH	Combined Heat and Power, Commercial Power	Coal	2,175
1998	OH	Combined Heat and Power, Commercial Power	Natural Gas	43,120
1998	OH	Combined Heat and Power, Commercial Power	Petroleum	3,911
1998	OH	Combined Heat and Power, Commercial Power	Wood and Wood Derived Fuels	1,727
1999	OH	Total Electric Power Industry	Total	142,330,431
1999	OH	Total Electric Power Industry	Coal	123,320,141
1999	OH	Total Electric Power Industry	Hydroelectric Conventional	423,031
1999	OH	Total Electric Power Industry	Natural Gas	886,446
1999	OH	Total Electric Power Industry	Nuclear	16,422,010
1999	OH	Total Electric Power Industry	Other Biomass	0
1999	OH	Total Electric Power Industry	Other Gases	156,424
1999	OH	Total Electric Power Industry	Petroleum	483,998
1999	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	638,381
1999	OH	Electric Generators, Electric Utilities	Total	140,912,140
1999	OH	Electric Generators, Electric Utilities	Coal	122,845,628
1999	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	423,031
1999	OH	Electric Generators, Electric Utilities	Natural Gas	747,385
1999	OH	Electric Generators, Electric Utilities	Nuclear	16,422,010
1999	OH	Electric Generators, Electric Utilities	Other Biomass	0
1999	OH	Electric Generators, Electric Utilities	Petroleum	474,086
1999	OH	Combined Heat and Power, Industrial Power	Total	1,297,749
1999	OH	Combined Heat and Power, Industrial Power	Coal	413,555
1999	OH	Combined Heat and Power, Industrial Power	Natural Gas	129,440
1999	OH	Combined Heat and Power, Industrial Power	Other Gases	156,424
1999	OH	Combined Heat and Power, Industrial Power	Petroleum	6,806
1999	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	591,524
1999	OH	Combined Heat and Power, Electric Power	Total	117,106
1999	OH	Combined Heat and Power, Electric Power	Coal	60,674
1999	OH	Combined Heat and Power, Electric Power	Natural Gas	6,907
1999	OH	Combined Heat and Power, Electric Power	Petroleum	3,097
1999	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	46,428
1999	OH	Combined Heat and Power, Commercial Power	Total	3,436
1999	OH	Combined Heat and Power, Commercial Power	Coal	284

Net Generation by State, Type of Producer and Energy Source

YEAR	STATE	TYPE OF PRODUCER	ENERGY SOURCE	GENERATION (Megawatthours)
1999	OH	Combined Heat and Power, Commercial Power	Natural Gas	2,714
1999	OH	Combined Heat and Power, Commercial Power	Petroleum	9
1999	OH	Combined Heat and Power, Commercial Power	Wood and Wood Derived Fuels	429
2000	OH	Total Electric Power Industry	Total	149,060,280
2000	OH	Total Electric Power Industry	Coal	129,578,544
2000	OH	Total Electric Power Industry	Hydroelectric Conventional	583,048
2000	OH	Total Electric Power Industry	Natural Gas	825,154
2000	OH	Total Electric Power Industry	Nuclear	16,781,378
2000	OH	Total Electric Power Industry	Other Biomass	26,849
2000	OH	Total Electric Power Industry	Other Gases	290,353
2000	OH	Total Electric Power Industry	Petroleum	354,412
2000	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	620,542
2000	OH	Electric Generators, Independent Power Producers	Total	3,156,853
2000	OH	Electric Generators, Independent Power Producers	Coal	2,948,583
2000	OH	Electric Generators, Independent Power Producers	Natural Gas	172,943
2000	OH	Electric Generators, Independent Power Producers	Other Biomass	26,849
2000	OH	Electric Generators, Independent Power Producers	Petroleum	8,478
2000	OH	Electric Generators, Electric Utilities	Total	144,358,306
2000	OH	Electric Generators, Electric Utilities	Coal	126,225,740
2000	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	583,048
2000	OH	Electric Generators, Electric Utilities	Natural Gas	425,821
2000	OH	Electric Generators, Electric Utilities	Nuclear	16,781,378
2000	OH	Electric Generators, Electric Utilities	Other Biomass	0
2000	OH	Electric Generators, Electric Utilities	Petroleum	342,319
2000	OH	Combined Heat and Power, Industrial Power	Total	1,265,893
2000	OH	Combined Heat and Power, Industrial Power	Coal	363,016
2000	OH	Combined Heat and Power, Industrial Power	Natural Gas	171,660
2000	OH	Combined Heat and Power, Industrial Power	Other Gases	153,063
2000	OH	Combined Heat and Power, Industrial Power	Petroleum	2,039
2000	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	576,115
2000	OH	Combined Heat and Power, Electric Power	Total	274,511
2000	OH	Combined Heat and Power, Electric Power	Coal	41,066
2000	OH	Combined Heat and Power, Electric Power	Natural Gas	50,764
2000	OH	Combined Heat and Power, Electric Power	Other Gases	137,290
2000	OH	Combined Heat and Power, Electric Power	Petroleum	1,368
2000	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	44,023
2000	OH	Combined Heat and Power, Commercial Power	Total	4,717
2000	OH	Combined Heat and Power, Commercial Power	Coal	139
2000	OH	Combined Heat and Power, Commercial Power	Natural Gas	3,966
2000	OH	Combined Heat and Power, Commercial Power	Petroleum	208
2000	OH	Combined Heat and Power, Commercial Power	Wood and Wood Derived Fuels	404
2001	OH	Total Electric Power Industry	Total	142,261,807
2001	OH	Total Electric Power Industry	Coal	124,213,236
2001	OH	Total Electric Power Industry	Hydroelectric Conventional	510,785
2001	OH	Total Electric Power Industry	Natural Gas	924,416
2001	OH	Total Electric Power Industry	Nuclear	15,463,762
2001	OH	Total Electric Power Industry	Other Biomass	27,888
2001	OH	Total Electric Power Industry	Other Gases	301,949
2001	OH	Total Electric Power Industry	Petroleum	416,698
2001	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	403,073
2001	OH	Electric Generators, Independent Power Producers	Total	5,242,389
2001	OH	Electric Generators, Independent Power Producers	Coal	4,877,672
2001	OH	Electric Generators, Independent Power Producers	Natural Gas	334,041
2001	OH	Electric Generators, Independent Power Producers	Other Biomass	27,888
2001	OH	Electric Generators, Independent Power Producers	Petroleum	2,788
2001	OH	Electric Generators, Electric Utilities	Total	135,484,174
2001	OH	Electric Generators, Electric Utilities	Coal	118,766,821
2001	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	510,785
2001	OH	Electric Generators, Electric Utilities	Natural Gas	336,372
2001	OH	Electric Generators, Electric Utilities	Nuclear	15,463,762
2001	OH	Electric Generators, Electric Utilities	Petroleum	406,434
2001	OH	Combined Heat and Power, Industrial Power	Total	1,247,498
2001	OH	Combined Heat and Power, Industrial Power	Coal	520,694
2001	OH	Combined Heat and Power, Industrial Power	Natural Gas	175,087

Net Generation by State, Type of Producer and Energy Source

YEAR	STATE	TYPE OF PRODUCER	ENERGY SOURCE	GENERATION (Megawatthours)
2001	OH	Combined Heat and Power, Industrial Power	Other Gases	183,305
2001	OH	Combined Heat and Power, Industrial Power	Petroleum	4,526
2001	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	363,886
2001	OH	Combined Heat and Power, Electric Power	Total	267,986
2001	OH	Combined Heat and Power, Electric Power	Coal	42,701
2001	OH	Combined Heat and Power, Electric Power	Natural Gas	66,246
2001	OH	Combined Heat and Power, Electric Power	Other Gases	118,644
2001	OH	Combined Heat and Power, Electric Power	Petroleum	1,423
2001	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	38,972
2001	OH	Combined Heat and Power, Commercial Power	Total	19,760
2001	OH	Combined Heat and Power, Commercial Power	Coal	5,348
2001	OH	Combined Heat and Power, Commercial Power	Natural Gas	12,670
2001	OH	Combined Heat and Power, Commercial Power	Petroleum	1,527
2001	OH	Combined Heat and Power, Commercial Power	Wood and Wood Derived Fuels	215
2002	OH	Total Electric Power Industry	Total	147,068,850
2002	OH	Total Electric Power Industry	Coal	132,953,066
2002	OH	Total Electric Power Industry	Hydroelectric Conventional	488,329
2002	OH	Total Electric Power Industry	Natural Gas	1,766,654
2002	OH	Total Electric Power Industry	Nuclear	10,864,902
2002	OH	Total Electric Power Industry	Other	248,904
2002	OH	Total Electric Power Industry	Other Biomass	25,244
2002	OH	Total Electric Power Industry	Other Gases	206,565
2002	OH	Total Electric Power Industry	Petroleum	389,119
2002	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	126,067
2002	OH	Electric Generators, Independent Power Producers	Total	6,421,090
2002	OH	Electric Generators, Independent Power Producers	Coal	5,289,185
2002	OH	Electric Generators, Independent Power Producers	Natural Gas	880,482
2002	OH	Electric Generators, Independent Power Producers	Other	221,672
2002	OH	Electric Generators, Independent Power Producers	Other Biomass	23,041
2002	OH	Electric Generators, Independent Power Producers	Petroleum	6,710
2002	OH	Electric Generators, Electric Utilities	Total	139,904,106
2002	OH	Electric Generators, Electric Utilities	Coal	127,373,404
2002	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	488,329
2002	OH	Electric Generators, Electric Utilities	Natural Gas	796,761
2002	OH	Electric Generators, Electric Utilities	Nuclear	10,864,902
2002	OH	Electric Generators, Electric Utilities	Petroleum	380,710
2002	OH	Combined Heat and Power, Industrial Power	Total	434,145
2002	OH	Combined Heat and Power, Industrial Power	Coal	246,625
2002	OH	Combined Heat and Power, Industrial Power	Natural Gas	24,094
2002	OH	Combined Heat and Power, Industrial Power	Other	27,232
2002	OH	Combined Heat and Power, Industrial Power	Other Biomass	2,203
2002	OH	Combined Heat and Power, Industrial Power	Other Gases	51,250
2002	OH	Combined Heat and Power, Industrial Power	Petroleum	529
2002	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	82,212
2002	OH	Combined Heat and Power, Electric Power	Total	302,029
2002	OH	Combined Heat and Power, Electric Power	Coal	43,128
2002	OH	Combined Heat and Power, Electric Power	Natural Gas	60,074
2002	OH	Combined Heat and Power, Electric Power	Other Gases	155,315
2002	OH	Combined Heat and Power, Electric Power	Petroleum	833
2002	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	42,679
2002	OH	Combined Heat and Power, Commercial Power	Total	7,479
2002	OH	Combined Heat and Power, Commercial Power	Coal	723
2002	OH	Combined Heat and Power, Commercial Power	Natural Gas	5,243
2002	OH	Combined Heat and Power, Commercial Power	Petroleum	337
2002	OH	Combined Heat and Power, Commercial Power	Wood and Wood Derived Fuels	1,176
2003	OH	Total Electric Power Industry	Total	146,638,128
2003	OH	Total Electric Power Industry	Coal	134,769,137
2003	OH	Total Electric Power Industry	Hydroelectric Conventional	510,835
2003	OH	Total Electric Power Industry	Natural Gas	1,793,584
2003	OH	Total Electric Power Industry	Nuclear	8,475,016
2003	OH	Total Electric Power Industry	Other	26,163
2003	OH	Total Electric Power Industry	Other Biomass	33,300
2003	OH	Total Electric Power Industry	Other Gases	212,523
2003	OH	Total Electric Power Industry	Petroleum	410,153

Net Generation by State, Type of Producer and Energy Source

YEAR	STATE	TYPE OF PRODUCER	ENERGY SOURCE	GENERATION (Megawatthours)
2003	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	407,417
2003	OH	Electric Generators, Independent Power Producers	Total	6,123,786
2003	OH	Electric Generators, Independent Power Producers	Coal	5,001,335
2003	OH	Electric Generators, Independent Power Producers	Natural Gas	1,080,609
2003	OH	Electric Generators, Independent Power Producers	Other Biomass	27,184
2003	OH	Electric Generators, Independent Power Producers	Petroleum	14,658
2003	OH	Electric Generators, Electric Utilities	Total	139,086,083
2003	OH	Electric Generators, Electric Utilities	Coal	129,255,272
2003	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	510,835
2003	OH	Electric Generators, Electric Utilities	Natural Gas	456,255
2003	OH	Electric Generators, Electric Utilities	Nuclear	8,475,016
2003	OH	Electric Generators, Electric Utilities	Petroleum	387,257
2003	OH	Electric Generators, Electric Utilities	Wood and Wood Derived Fuels	1,448
2003	OH	Combined Heat and Power, Industrial Power	Total	1,040,665
2003	OH	Combined Heat and Power, Industrial Power	Coal	511,726
2003	OH	Combined Heat and Power, Industrial Power	Natural Gas	43,299
2003	OH	Combined Heat and Power, Industrial Power	Other	26,163
2003	OH	Combined Heat and Power, Industrial Power	Other Biomass	6,116
2003	OH	Combined Heat and Power, Industrial Power	Other Gases	88,439
2003	OH	Combined Heat and Power, Industrial Power	Petroleum	8,066
2003	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	356,856
2003	OH	Combined Heat and Power, Electric Power	Total	381,549
2003	OH	Combined Heat and Power, Electric Power	Natural Gas	208,352
2003	OH	Combined Heat and Power, Electric Power	Other Gases	124,084
2003	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	49,113
2003	OH	Combined Heat and Power, Commercial Power	Total	6,045
2003	OH	Combined Heat and Power, Commercial Power	Coal	804
2003	OH	Combined Heat and Power, Commercial Power	Natural Gas	5,068
2003	OH	Combined Heat and Power, Commercial Power	Petroleum	173
2003	OH	Combined Heat and Power, Commercial Power	Wood and Wood Derived Fuels	0
2004	OH	Total Electric Power Industry	Total	148,345,905
2004	OH	Total Electric Power Industry	Coal	128,156,782
2004	OH	Total Electric Power Industry	Hydroelectric Conventional	729,876
2004	OH	Total Electric Power Industry	Natural Gas	1,390,995
2004	OH	Total Electric Power Industry	Nuclear	15,950,121
2004	OH	Total Electric Power Industry	Other	11
2004	OH	Total Electric Power Industry	Other Biomass	30,069
2004	OH	Total Electric Power Industry	Other Gases	302,063
2004	OH	Total Electric Power Industry	Petroleum	1,388,281
2004	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	397,708
2004	OH	Electric Generators, Independent Power Producers	Total	4,699,059
2004	OH	Electric Generators, Independent Power Producers	Coal	3,707,990
2004	OH	Electric Generators, Independent Power Producers	Natural Gas	939,099
2004	OH	Electric Generators, Independent Power Producers	Other Biomass	26,368
2004	OH	Electric Generators, Independent Power Producers	Petroleum	25,602
2004	OH	Electric Generators, Electric Utilities	Total	142,305,499
2004	OH	Electric Generators, Electric Utilities	Coal	124,004,082
2004	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	729,876
2004	OH	Electric Generators, Electric Utilities	Natural Gas	266,954
2004	OH	Electric Generators, Electric Utilities	Nuclear	15,950,121
2004	OH	Electric Generators, Electric Utilities	Petroleum	1,354,023
2004	OH	Electric Generators, Electric Utilities	Wood and Wood Derived Fuels	443
2004	OH	Combined Heat and Power, Industrial Power	Total	1,022,053
2004	OH	Combined Heat and Power, Industrial Power	Coal	444,607
2004	OH	Combined Heat and Power, Industrial Power	Natural Gas	34,360
2004	OH	Combined Heat and Power, Industrial Power	Other Biomass	3,701
2004	OH	Combined Heat and Power, Industrial Power	Other Gases	179,207
2004	OH	Combined Heat and Power, Industrial Power	Petroleum	8,649
2004	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	351,530
2004	OH	Combined Heat and Power, Electric Power	Total	319,134
2004	OH	Combined Heat and Power, Electric Power	Natural Gas	150,579
2004	OH	Combined Heat and Power, Electric Power	Other Gases	122,857
2004	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	45,698
2004	OH	Combined Heat and Power, Commercial Power	Total	160

Net Generation by State, Type of Producer and Energy Source

YEAR	STATE	TYPE OF PRODUCER	ENERGY SOURCE	GENERATION (Megawatthours)
2004	OH	Combined Heat and Power, Commercial Power	Coal	103
2004	OH	Combined Heat and Power, Commercial Power	Natural Gas	3
2004	OH	Combined Heat and Power, Commercial Power	Other	11
2004	OH	Combined Heat and Power, Commercial Power	Petroleum	6
2004	OH	Combined Heat and Power, Commercial Power	Wood and Wood Derived Fuels	37
2005	OH	Total Electric Power Industry	Total	156,976,323
2005	OH	Total Electric Power Industry	Coal	136,825,598
2005	OH	Total Electric Power Industry	Hydroelectric Conventional	515,744
2005	OH	Total Electric Power Industry	Natural Gas	2,695,628
2005	OH	Total Electric Power Industry	Nuclear	14,802,733
2005	OH	Total Electric Power Industry	Other	2,299
2005	OH	Total Electric Power Industry	Other Biomass	26,761
2005	OH	Total Electric Power Industry	Other Gases	298,339
2005	OH	Total Electric Power Industry	Petroleum	1,390,393
2005	OH	Total Electric Power Industry	Wind	13,268
2005	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	405,560
2005	OH	Electric Generators, Independent Power Producers	Total	52,817,248
2005	OH	Electric Generators, Independent Power Producers	Coal	35,032,276
2005	OH	Electric Generators, Independent Power Producers	Natural Gas	1,831,075
2005	OH	Electric Generators, Independent Power Producers	Nuclear	14,802,733
2005	OH	Electric Generators, Independent Power Producers	Other Biomass	22,526
2005	OH	Electric Generators, Independent Power Producers	Petroleum	1,128,638
2005	OH	Electric Generators, Electric Utilities	Total	102,750,838
2005	OH	Electric Generators, Electric Utilities	Coal	101,302,047
2005	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	515,744
2005	OH	Electric Generators, Electric Utilities	Natural Gas	665,873
2005	OH	Electric Generators, Electric Utilities	Petroleum	253,906
2005	OH	Electric Generators, Electric Utilities	Wind	13,268
2005	OH	Electric Generators, Electric Utilities	Wood and Wood Derived Fuels	0
2005	OH	Combined Heat and Power, Industrial Power	Total	1,080,335
2005	OH	Combined Heat and Power, Industrial Power	Coal	491,171
2005	OH	Combined Heat and Power, Industrial Power	Natural Gas	32,624
2005	OH	Combined Heat and Power, Industrial Power	Other	2,293
2005	OH	Combined Heat and Power, Industrial Power	Other Biomass	4,235
2005	OH	Combined Heat and Power, Industrial Power	Other Gases	180,916
2005	OH	Combined Heat and Power, Industrial Power	Petroleum	7,849
2005	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	361,248
2005	OH	Combined Heat and Power, Electric Power	Total	327,753
2005	OH	Combined Heat and Power, Electric Power	Natural Gas	166,056
2005	OH	Combined Heat and Power, Electric Power	Other Gases	117,424
2005	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	44,273
2005	OH	Combined Heat and Power, Commercial Power	Total	149
2005	OH	Combined Heat and Power, Commercial Power	Coal	104
2005	OH	Combined Heat and Power, Commercial Power	Natural Gas	0
2005	OH	Combined Heat and Power, Commercial Power	Other	6
2005	OH	Combined Heat and Power, Commercial Power	Petroleum	0
2005	OH	Combined Heat and Power, Commercial Power	Wood and Wood Derived Fuels	39
2006	OH	Total Electric Power Industry	Total	155,434,075
2006	OH	Total Electric Power Industry	Coal	133,400,156
2006	OH	Total Electric Power Industry	Hydroelectric Conventional	631,936
2006	OH	Total Electric Power Industry	Natural Gas	2,379,062
2006	OH	Total Electric Power Industry	Nuclear	16,846,939
2006	OH	Total Electric Power Industry	Other	2,805
2006	OH	Total Electric Power Industry	Other Biomass	34,121
2006	OH	Total Electric Power Industry	Other Gases	360,007
2006	OH	Total Electric Power Industry	Petroleum	1,354,555
2006	OH	Total Electric Power Industry	Wind	14,401
2006	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	410,093
2006	OH	Electric Generators, Independent Power Producers	Total	55,835,704
2006	OH	Electric Generators, Independent Power Producers	Coal	36,270,579
2006	OH	Electric Generators, Independent Power Producers	Natural Gas	1,606,267
2006	OH	Electric Generators, Independent Power Producers	Nuclear	16,846,939
2006	OH	Electric Generators, Independent Power Producers	Other Biomass	23,653
2006	OH	Electric Generators, Independent Power Producers	Petroleum	1,088,266

Net Generation by State, Type of Producer and Energy Source

YEAR	STATE	TYPE OF PRODUCER	ENERGY SOURCE	GENERATION (Megawatthours)
2006	OH	Electric Generators, Electric Utilities	Total	98,159,139
2006	OH	Electric Generators, Electric Utilities	Coal	96,674,346
2006	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	631,936
2006	OH	Electric Generators, Electric Utilities	Natural Gas	592,505
2006	OH	Electric Generators, Electric Utilities	Petroleum	245,951
2006	OH	Electric Generators, Electric Utilities	Wind	14,401
2006	OH	Electric Generators, Electric Utilities	Wood and Wood Derived Fuels	0
2006	OH	Combined Heat and Power, Industrial Power	Total	1,117,355
2006	OH	Combined Heat and Power, Industrial Power	Coal	455,231
2006	OH	Combined Heat and Power, Industrial Power	Natural Gas	32,824
2006	OH	Combined Heat and Power, Industrial Power	Other	2,805
2006	OH	Combined Heat and Power, Industrial Power	Other Biomass	10,468
2006	OH	Combined Heat and Power, Industrial Power	Other Gases	223,479
2006	OH	Combined Heat and Power, Industrial Power	Petroleum	20,338
2006	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	372,209
2006	OH	Combined Heat and Power, Electric Power	Total	321,877
2006	OH	Combined Heat and Power, Electric Power	Natural Gas	147,465
2006	OH	Combined Heat and Power, Electric Power	Other Gases	136,528
2006	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	37,883
2006	OH	Combined Heat and Power, Commercial Power	Total	0
2006	OH	Combined Heat and Power, Commercial Power	Coal	0
2006	OH	Combined Heat and Power, Commercial Power	Natural Gas	0
2007	OH	Total Electric Power Industry	Total	155,155,545
2007	OH	Total Electric Power Industry	Coal	133,130,679
2007	OH	Total Electric Power Industry	Hydroelectric Conventional	410,436
2007	OH	Total Electric Power Industry	Natural Gas	3,974,897
2007	OH	Total Electric Power Industry	Nuclear	15,764,049
2007	OH	Total Electric Power Industry	Other	3,322
2007	OH	Total Electric Power Industry	Other Biomass	21,017
2007	OH	Total Electric Power Industry	Other Gases	289,273
2007	OH	Total Electric Power Industry	Petroleum	1,147,746
2007	OH	Total Electric Power Industry	Wind	14,748
2007	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	399,378
2007	OH	Electric Generators, Independent Power Producers	Total	53,365,757
2007	OH	Electric Generators, Independent Power Producers	Coal	33,989,248
2007	OH	Electric Generators, Independent Power Producers	Natural Gas	2,702,658
2007	OH	Electric Generators, Independent Power Producers	Nuclear	15,764,049
2007	OH	Electric Generators, Independent Power Producers	Other Biomass	10,972
2007	OH	Electric Generators, Independent Power Producers	Petroleum	898,830
2007	OH	Electric Generators, Electric Utilities	Total	100,536,445
2007	OH	Electric Generators, Electric Utilities	Coal	98,791,919
2007	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	410,436
2007	OH	Electric Generators, Electric Utilities	Natural Gas	1,078,551
2007	OH	Electric Generators, Electric Utilities	Other	0
2007	OH	Electric Generators, Electric Utilities	Petroleum	240,791
2007	OH	Electric Generators, Electric Utilities	Wind	14,748
2007	OH	Electric Generators, Electric Utilities	Wood and Wood Derived Fuels	0
2007	OH	Combined Heat and Power, Industrial Power	Total	903,300
2007	OH	Combined Heat and Power, Industrial Power	Coal	349,512
2007	OH	Combined Heat and Power, Industrial Power	Natural Gas	28,978
2007	OH	Combined Heat and Power, Industrial Power	Other	3,322
2007	OH	Combined Heat and Power, Industrial Power	Other Biomass	10,045
2007	OH	Combined Heat and Power, Industrial Power	Other Gases	135,150
2007	OH	Combined Heat and Power, Industrial Power	Petroleum	8,124
2007	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	368,169
2007	OH	Combined Heat and Power, Electric Power	Total	350,043
2007	OH	Combined Heat and Power, Electric Power	Natural Gas	164,711
2007	OH	Combined Heat and Power, Electric Power	Other Gases	154,123
2007	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	31,210
2007	OH	Combined Heat and Power, Commercial Power	Total	0
2007	OH	Combined Heat and Power, Commercial Power	Coal	0
2007	OH	Combined Heat and Power, Commercial Power	Natural Gas	0
2007	OH	Combined Heat and Power, Commercial Power	Other	0
2007	OH	Combined Heat and Power, Commercial Power	Petroleum	0

Net Generation by State, Type of Producer and Energy Source

YEAR	STATE	TYPE OF PRODUCER	ENERGY SOURCE	GENERATION (Megawatthours)
2007	OH	Combined Heat and Power, Commercial Power	Wood and Wood Derived Fuels	0
2008	OH	Total Electric Power Industry	Total	153,412,251
2008	OH	Total Electric Power Industry	Coal	130,694,310
2008	OH	Total Electric Power Industry	Hydroelectric Conventional	386,435
2008	OH	Total Electric Power Industry	Natural Gas	2,484,391
2008	OH	Total Electric Power Industry	Nuclear	17,513,878
2008	OH	Total Electric Power Industry	Other	11,000
2008	OH	Total Electric Power Industry	Other Biomass	190,175
2008	OH	Total Electric Power Industry	Other Gases	260,924
2008	OH	Total Electric Power Industry	Petroleum	1,437,938
2008	OH	Total Electric Power Industry	Wind	15,084
2008	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	418,117
2008	OH	Electric Generators, Independent Power Producers	Total	53,646,205
2008	OH	Electric Generators, Independent Power Producers	Coal	33,010,237
2008	OH	Electric Generators, Independent Power Producers	Natural Gas	1,854,659
2008	OH	Electric Generators, Independent Power Producers	Nuclear	17,513,878
2008	OH	Electric Generators, Independent Power Producers	Other Biomass	182,666
2008	OH	Electric Generators, Independent Power Producers	Petroleum	1,084,765
2008	OH	Electric Generators, Electric Utilities	Total	98,396,809
2008	OH	Electric Generators, Electric Utilities	Coal	97,315,864
2008	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	386,435
2008	OH	Electric Generators, Electric Utilities	Natural Gas	435,717
2008	OH	Electric Generators, Electric Utilities	Other	0
2008	OH	Electric Generators, Electric Utilities	Other Gases	102
2008	OH	Electric Generators, Electric Utilities	Petroleum	243,608
2008	OH	Electric Generators, Electric Utilities	Wind	15,084
2008	OH	Combined Heat and Power, Industrial Power	Total	1,071,588
2008	OH	Combined Heat and Power, Industrial Power	Coal	368,209
2008	OH	Combined Heat and Power, Industrial Power	Natural Gas	33,450
2008	OH	Combined Heat and Power, Industrial Power	Other	11,000
2008	OH	Combined Heat and Power, Industrial Power	Other Biomass	7,509
2008	OH	Combined Heat and Power, Industrial Power	Other Gases	152,815
2008	OH	Combined Heat and Power, Industrial Power	Petroleum	109,564
2008	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	389,041
2008	OH	Combined Heat and Power, Electric Power	Total	297,649
2008	OH	Combined Heat and Power, Electric Power	Natural Gas	160,566
2008	OH	Combined Heat and Power, Electric Power	Other Gases	108,007
2008	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	29,076
2009	OH	Total Electric Power Industry	Total	136,090,225
2009	OH	Total Electric Power Industry	Coal	113,711,997
2009	OH	Total Electric Power Industry	Hydroelectric Conventional	527,746
2009	OH	Total Electric Power Industry	Natural Gas	4,650,456
2009	OH	Total Electric Power Industry	Nuclear	15,206,084
2009	OH	Total Electric Power Industry	Other	11,312
2009	OH	Total Electric Power Industry	Other Biomass	209,611
2009	OH	Total Electric Power Industry	Other Gases	37,477
2009	OH	Total Electric Power Industry	Petroleum	1,311,743
2009	OH	Total Electric Power Industry	Wind	14,114
2009	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	409,685
2009	OH	Electric Generators, Independent Power Producers	Total	40,775,148
2009	OH	Electric Generators, Independent Power Producers	Coal	20,714,120
2009	OH	Electric Generators, Independent Power Producers	Natural Gas	3,650,818
2009	OH	Electric Generators, Independent Power Producers	Nuclear	15,206,084
2009	OH	Electric Generators, Independent Power Producers	Other Biomass	198,144
2009	OH	Electric Generators, Independent Power Producers	Petroleum	1,005,982
2009	OH	Electric Generators, Electric Utilities	Total	93,939,609
2009	OH	Electric Generators, Electric Utilities	Coal	92,371,924
2009	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	527,746
2009	OH	Electric Generators, Electric Utilities	Natural Gas	820,233
2009	OH	Electric Generators, Electric Utilities	Other Gases	811
2009	OH	Electric Generators, Electric Utilities	Petroleum	204,781
2009	OH	Electric Generators, Electric Utilities	Wind	14,114
2009	OH	Combined Heat and Power, Industrial Power	Total	903,040
2009	OH	Combined Heat and Power, Industrial Power	Coal	328,707

Net Generation by State, Type of Producer and Energy Source

YEAR	STATE	TYPE OF PRODUCER	ENERGY SOURCE	GENERATION (Megawatthours)
2009	OH	Combined Heat and Power, Industrial Power	Natural Gas	30,339
2009	OH	Combined Heat and Power, Industrial Power	Other	11,312
2009	OH	Combined Heat and Power, Industrial Power	Other Biomass	11,467
2009	OH	Combined Heat and Power, Industrial Power	Other Gases	33,590
2009	OH	Combined Heat and Power, Industrial Power	Petroleum	100,980
2009	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	386,645
2009	OH	Combined Heat and Power, Electric Power	Total	472,428
2009	OH	Combined Heat and Power, Electric Power	Coal	297,246
2009	OH	Combined Heat and Power, Electric Power	Natural Gas	149,066
2009	OH	Combined Heat and Power, Electric Power	Other Gases	3,076
2009	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	23,041
2009	OH	Combined Heat and Power, Commercial Power	Total	0
2009	OH	Combined Heat and Power, Commercial Power	Coal	0
2009	OH	Combined Heat and Power, Commercial Power	Natural Gas	0
2010	OH	Total Electric Power Industry	Total	143,598,337
2010	OH	Total Electric Power Industry	Coal	117,828,009
2010	OH	Total Electric Power Industry	Hydroelectric Conventional	429,024
2010	OH	Total Electric Power Industry	Natural Gas	7,127,859
2010	OH	Total Electric Power Industry	Nuclear	15,804,803
2010	OH	Total Electric Power Industry	Other	12,030
2010	OH	Total Electric Power Industry	Other Biomass	275,855
2010	OH	Total Electric Power Industry	Other Gases	254,099
2010	OH	Total Electric Power Industry	Petroleum	1,442,424
2010	OH	Total Electric Power Industry	Solar Thermal and Photovoltaic	12,848
2010	OH	Total Electric Power Industry	Wind	12,576
2010	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	398,810
2010	OH	Electric Generators, Independent Power Producers	Total	49,722,340
2010	OH	Electric Generators, Independent Power Producers	Coal	27,192,085
2010	OH	Electric Generators, Independent Power Producers	Natural Gas	5,339,537
2010	OH	Electric Generators, Independent Power Producers	Nuclear	15,804,803
2010	OH	Electric Generators, Independent Power Producers	Other	0
2010	OH	Electric Generators, Independent Power Producers	Other Biomass	263,696
2010	OH	Electric Generators, Independent Power Producers	Petroleum	1,111,296
2010	OH	Electric Generators, Independent Power Producers	Solar Thermal and Photovoltaic	10,923
2010	OH	Electric Generators, Electric Utilities	Total	92,198,096
2010	OH	Electric Generators, Electric Utilities	Coal	89,927,804
2010	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	429,024
2010	OH	Electric Generators, Electric Utilities	Natural Gas	1,587,363
2010	OH	Electric Generators, Electric Utilities	Other Gases	569
2010	OH	Electric Generators, Electric Utilities	Petroleum	238,836
2010	OH	Electric Generators, Electric Utilities	Solar Thermal and Photovoltaic	1,925
2010	OH	Electric Generators, Electric Utilities	Wind	12,576
2010	OH	Combined Heat and Power, Industrial Power	Total	1,025,918
2010	OH	Combined Heat and Power, Industrial Power	Coal	343,650
2010	OH	Combined Heat and Power, Industrial Power	Natural Gas	44,944
2010	OH	Combined Heat and Power, Industrial Power	Other	12,030
2010	OH	Combined Heat and Power, Industrial Power	Other Biomass	12,159
2010	OH	Combined Heat and Power, Industrial Power	Other Gases	149,570
2010	OH	Combined Heat and Power, Industrial Power	Petroleum	92,293
2010	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	371,273
2010	OH	Combined Heat and Power, Electric Power	Total	651,983
2010	OH	Combined Heat and Power, Electric Power	Coal	364,470
2010	OH	Combined Heat and Power, Electric Power	Natural Gas	156,016
2010	OH	Combined Heat and Power, Electric Power	Other Gases	103,960
2010	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	27,537
2011	OH	Total Electric Power Industry	Total	135,585,804
2011	OH	Total Electric Power Industry	Coal	105,336,957
2011	OH	Total Electric Power Industry	Hydroelectric Conventional	383,655
2011	OH	Total Electric Power Industry	Natural Gas	12,337,577
2011	OH	Total Electric Power Industry	Nuclear	14,889,746
2011	OH	Total Electric Power Industry	Other	10,003
2011	OH	Total Electric Power Industry	Other Biomass	331,756
2011	OH	Total Electric Power Industry	Other Gases	303,743
2011	OH	Total Electric Power Industry	Petroleum	1,388,432

Net Generation by State, Type of Producer and Energy Source

YEAR	STATE	TYPE OF PRODUCER	ENERGY SOURCE	GENERATION (Megawatthours)
2011	OH	Total Electric Power Industry	Solar Thermal and Photovoltaic	15,495
2011	OH	Total Electric Power Industry	Wind	198,443
2011	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	389,998
2011	OH	Electric Generators, Independent Power Producers	Total	48,792,705
2011	OH	Electric Generators, Independent Power Producers	Coal	23,199,555
2011	OH	Electric Generators, Independent Power Producers	Natural Gas	9,069,400
2011	OH	Electric Generators, Independent Power Producers	Nuclear	14,889,746
2011	OH	Electric Generators, Independent Power Producers	Other	0
2011	OH	Electric Generators, Independent Power Producers	Other Biomass	315,229
2011	OH	Electric Generators, Independent Power Producers	Petroleum	1,122,488
2011	OH	Electric Generators, Independent Power Producers	Solar Thermal and Photovoltaic	14,159
2011	OH	Electric Generators, Independent Power Producers	Wind	182,128
2011	OH	Electric Generators, Electric Utilities	Total	85,006,849
2011	OH	Electric Generators, Electric Utilities	Coal	81,470,233
2011	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	383,655
2011	OH	Electric Generators, Electric Utilities	Natural Gas	2,873,461
2011	OH	Electric Generators, Electric Utilities	Petroleum	263,785
2011	OH	Electric Generators, Electric Utilities	Solar Thermal and Photovoltaic	1,336
2011	OH	Electric Generators, Electric Utilities	Wind	14,379
2011	OH	Combined Heat and Power, Industrial Power	Total	961,619
2011	OH	Combined Heat and Power, Industrial Power	Coal	315,118
2011	OH	Combined Heat and Power, Industrial Power	Natural Gas	63,030
2011	OH	Combined Heat and Power, Industrial Power	Other	10,003
2011	OH	Combined Heat and Power, Industrial Power	Other Biomass	16,527
2011	OH	Combined Heat and Power, Industrial Power	Other Gases	187,754
2011	OH	Combined Heat and Power, Industrial Power	Petroleum	1,983
2011	OH	Combined Heat and Power, Industrial Power	Wind	1,936
2011	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	365,269
2011	OH	Combined Heat and Power, Electric Power	Total	652,498
2011	OH	Combined Heat and Power, Electric Power	Coal	351,032
2011	OH	Combined Heat and Power, Electric Power	Natural Gas	160,748
2011	OH	Combined Heat and Power, Electric Power	Other Gases	115,989
2011	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	24,729
2011	OH	Combined Heat and Power, Commercial Power	Total	172,134
2011	OH	Combined Heat and Power, Commercial Power	Coal	1,019
2011	OH	Combined Heat and Power, Commercial Power	Natural Gas	170,938
2011	OH	Combined Heat and Power, Commercial Power	Petroleum	177
2012	OH	Total Electric Power Industry	Total	129,745,731
2012	OH	Total Electric Power Industry	Coal	85,588,636
2012	OH	Total Electric Power Industry	Hydroelectric Conventional	414,161
2012	OH	Total Electric Power Industry	Natural Gas	22,665,385
2012	OH	Total Electric Power Industry	Nuclear	17,086,998
2012	OH	Total Electric Power Industry	Other	11,928
2012	OH	Total Electric Power Industry	Other Biomass	365,613
2012	OH	Total Electric Power Industry	Other Gases	958,869
2012	OH	Total Electric Power Industry	Petroleum	1,281,132
2012	OH	Total Electric Power Industry	Solar Thermal and Photovoltaic	36,637
2012	OH	Total Electric Power Industry	Wind	985,485
2012	OH	Total Electric Power Industry	Wood and Wood Derived Fuels	350,888
2012	OH	Electric Generators, Independent Power Producers	Total	52,432,142
2012	OH	Electric Generators, Independent Power Producers	Coal	16,826,869
2012	OH	Electric Generators, Independent Power Producers	Natural Gas	16,118,416
2012	OH	Electric Generators, Independent Power Producers	Nuclear	17,086,998
2012	OH	Electric Generators, Independent Power Producers	Other Biomass	348,995
2012	OH	Electric Generators, Independent Power Producers	Petroleum	1,061,057
2012	OH	Electric Generators, Independent Power Producers	Solar Thermal and Photovoltaic	30,544
2012	OH	Electric Generators, Independent Power Producers	Wind	959,264
2012	OH	Electric Generators, Electric Utilities	Total	75,183,893
2012	OH	Electric Generators, Electric Utilities	Coal	68,519,305
2012	OH	Electric Generators, Electric Utilities	Hydroelectric Conventional	414,161
2012	OH	Electric Generators, Electric Utilities	Natural Gas	6,015,429
2012	OH	Electric Generators, Electric Utilities	Petroleum	214,920
2012	OH	Electric Generators, Electric Utilities	Solar Thermal and Photovoltaic	5,845
2012	OH	Electric Generators, Electric Utilities	Wind	14,233

Net Generation by State, Type of Producer and Energy Source

YEAR	STATE	TYPE OF PRODUCER	ENERGY SOURCE	GENERATION (Megawatthours)
2012	OH	Combined Heat and Power, Industrial Power	Total	1,317,487
2012	OH	Combined Heat and Power, Industrial Power	Coal	240,068
2012	OH	Combined Heat and Power, Industrial Power	Natural Gas	100,331
2012	OH	Combined Heat and Power, Industrial Power	Other	11,928
2012	OH	Combined Heat and Power, Industrial Power	Other Biomass	12,583
2012	OH	Combined Heat and Power, Industrial Power	Other Gases	608,634
2012	OH	Combined Heat and Power, Industrial Power	Petroleum	4,903
2012	OH	Combined Heat and Power, Industrial Power	Wind	11,988
2012	OH	Combined Heat and Power, Industrial Power	Wood and Wood Derived Fuels	327,053
2012	OH	Combined Heat and Power, Electric Power	Total	529,558
2012	OH	Combined Heat and Power, Electric Power	Coal	0
2012	OH	Combined Heat and Power, Electric Power	Natural Gas	151,452
2012	OH	Combined Heat and Power, Electric Power	Other Biomass	4,035
2012	OH	Combined Heat and Power, Electric Power	Other Gases	350,235
2012	OH	Combined Heat and Power, Electric Power	Wood and Wood Derived Fuels	23,835
2012	OH	Combined Heat and Power, Commercial Power	Total	282,651
2012	OH	Combined Heat and Power, Commercial Power	Coal	2,395
2012	OH	Combined Heat and Power, Commercial Power	Natural Gas	279,757
2012	OH	Combined Heat and Power, Commercial Power	Petroleum	252
2012	OH	Combined Heat and Power, Commercial Power	Solar Thermal and Photovoltaic	248

Appendix L:

EIA Annual Retail Sales of Electricity for Ohio: 1990-2012

Retail Sales of Electricity (Megawatthours) by State by Sector by Provider, 1990-2012								
Year	State	Industry Sector Category	Residential	Commercial	Industrial	Transportation	Other	Total
2012	OH	Total Electric Industry	52,287,769	46,755,882	53,379,284	33,929	NA	152,456,864
2012	OH	Full-Service Providers	33,995,689	16,013,465	22,022,940	1,636	NA	72,033,730
2012	OH	Energy-Only Providers	18,292,080	30,742,417	31,356,344	32,293	NA	80,423,134
2011	OH	Total Electric Industry	53,687,111	47,111,763	53,913,437	33,999	NA	154,746,310
2011	OH	Full-Service Providers	38,924,198	20,789,476	28,683,103	1,133	NA	88,397,910
2011	OH	Energy-Only Providers	14,762,913	26,322,287	25,230,334	32,866	NA	66,348,400
2010	OH	Total Electric Industry	54,474,377	46,525,627	53,109,368	36,046	NA	154,145,418
2010	OH	Full-Service Providers	44,252,697	28,519,152	32,550,166	7,782	NA	105,329,797
2010	OH	Energy-Only Providers	10,221,680	18,006,475	20,559,202	28,264	NA	48,815,621
2009	OH	Total Electric Industry	51,405,162	45,369,743	49,485,875	39,013	NA	146,299,793
2009	OH	Full-Service Providers	48,732,287	41,300,548	43,275,319	39,013	NA	133,347,167
2009	OH	Energy-Only Providers	2,672,875	4,069,195	6,210,556	0	NA	12,952,626
2008	OH	Total Electric Industry	53,410,599	47,310,241	58,620,567	47,400	NA	159,388,807
2008	OH	Full-Service Providers	51,279,701	42,643,463	53,661,383	47,400	NA	147,631,947
2008	OH	Energy-Only Providers	2,130,898	4,666,778	4,959,184	0	NA	11,756,860
2007	OH	Total Electric Industry	54,375,759	48,128,512	59,218,957	47,599	NA	161,770,827
2007	OH	Full-Service Providers	52,028,402	43,055,207	53,796,977	47,599	NA	148,928,185
2007	OH	Energy-Only Providers	2,347,357	5,073,305	5,421,980	0	NA	12,842,642
2006	OH	Total Electric Industry	51,375,232	46,140,704	55,869,283	43,625	NA	153,428,844
2006	OH	Full-Service Providers	48,933,579	41,040,401	50,241,251	43,625	NA	140,258,856
2006	OH	Energy-Only Providers	2,441,653	5,100,303	5,628,032	0	NA	13,169,988
2005	OH	Total Electric Industry	53,904,244	46,869,755	59,354,379	47,925	NA	160,176,303
2005	OH	Full-Service Providers	46,182,883	36,735,429	50,494,414	47,925	NA	133,460,651
2005	OH	Energy-Only Providers	7,721,361	10,134,326	8,859,965	0	NA	26,715,652
2004	OH	Total Electric Industry	50,300,038	45,313,453	58,558,349	49,274	NA	154,221,114
2004	OH	Full-Service Providers	42,952,465	34,657,382	48,680,188	49,274	NA	126,339,309
2004	OH	Energy-Only Providers	7,347,573	10,656,071	9,878,161	0	NA	27,881,805
2003	OH	Total Electric Industry	49,620,578	44,736,571	57,827,582	4,507	NA	152,189,238
2003	OH	Full-Service Providers	42,959,181	35,147,697	49,137,696	4,507	NA	127,249,081
2003	OH	Energy-Only Providers	6,661,397	9,588,874	8,689,886	0	NA	24,940,157
2002	OH	Total Electric Industry	50,863,643	39,924,173	58,471,510	NA	4,147,772	153,407,098
2002	OH	Full-Service Providers	45,618,743	33,653,994	49,554,936	NA	4,142,972	132,970,645
2002	OH	Energy-Only Providers	5,244,900	6,270,179	8,916,574	NA	4,800	20,436,453
2001	OH	Total Electric Industry	47,346,163	39,372,078	65,098,733	NA	3,980,740	155,797,714
2001	OH	Full-Service Providers	45,784,318	37,002,089	57,833,918	NA	3,817,716	144,438,041
2001	OH	Energy-Only Providers	1,561,845	2,369,989	7,264,815	NA	163,024	11,359,673
2000	OH	Total Electric Industry	46,488,137	40,757,137	74,019,337	NA	3,930,246	165,194,857
2000	OH	Full-Service Providers	46,488,137	40,757,137	69,917,940	NA	3,930,246	161,093,460
2000	OH	Energy-Only Providers	0	0	4,101,397	NA	0	4,101,397
1999	OH	Total Electric Industry	46,628,504	39,461,042	74,292,951	NA	3,888,333	164,270,830
1999	OH	Full-Service Providers	46,628,504	39,461,042	74,292,951	NA	3,888,165	164,270,662
1999	OH	Energy-Only Providers	0	0	0	NA	168	168
1998	OH	Total Electric Industry	44,516,171	38,471,813	72,998,337	NA	3,806,855	159,793,176
1998	OH	Full-Service Providers	44,516,171	38,471,813	72,998,337	NA	3,806,855	159,793,176
1997	OH	Total Electric Industry	43,634,915	36,373,148	73,888,462	NA	4,611,569	158,508,094
1997	OH	Full-Service Providers	43,634,915	36,373,148	73,888,462	NA	4,611,569	158,508,094
1996	OH	Total Electric Industry	44,573,250	36,034,487	73,394,154	NA	4,585,446	158,587,337
1996	OH	Full-Service Providers	44,573,250	36,034,487	73,394,154	NA	4,585,446	158,587,337
1995	OH	Total Electric Industry	44,010,400	35,549,248	74,473,401	NA	4,592,497	158,625,546
1995	OH	Full-Service Providers	44,010,400	35,549,248	74,473,401	NA	4,592,497	158,625,546
1994	OH	Total Electric Industry	41,791,275	34,053,066	74,010,054	NA	4,522,314	154,376,709
1994	OH	Full-Service Providers	41,791,275	34,053,066	74,010,054	NA	4,522,314	154,376,709
1993	OH	Total Electric Industry	41,950,456	33,298,608	68,831,023	NA	4,490,578	148,570,665
1993	OH	Full-Service Providers	41,950,456	33,298,608	68,831,023	NA	4,490,578	148,570,665
1992	OH	Total Electric Industry	39,140,657	31,818,312	69,674,159	NA	4,383,336	145,016,464
1992	OH	Full-Service Providers	39,140,657	31,818,312	69,674,159	NA	4,383,336	145,016,464
1991	OH	Total Electric Industry	40,942,449	32,325,493	67,856,138	NA	4,534,240	145,658,320
1991	OH	Full-Service Providers	40,942,449	32,325,493	67,856,138	NA	4,534,240	145,658,320
1990	OH	Total Electric Industry	37,889,450	30,540,857	69,681,659	NA	4,353,506	142,465,472
1990	OH	Full-Service Providers	37,889,450	30,540,857	69,681,659	NA	4,353,506	142,465,472

Appendix M:

OAC Chapter 4901:1-40 Alternative Energy Portfolio Standard

Chapter 4901:1-40 [Alternative Energy Portfolio Standard]

4901:1-40-01 Definitions.

(A) "Advanced energy fund" has the meaning set forth in section 4928.61 of the Revised Code.

(B) "Advanced energy resource" has the meaning set forth in division (A)(34) of section 4928.01 of the Revised Code.

(C) "Alternative energy resource" has the meaning set forth in division (A)(1) of section 4928.64 of the Revised Code.

(D) "Biologically derived methane gas" means landfill methane gas; or gas from the anaerobic digestion of organic materials, including animal waste, municipal wastewater, institutional and industrial organic waste, food waste, yard waste, and agricultural crops and residues.

(E) "Biomass energy" means energy produced from organic material derived from plants or animals and available on a renewable basis, including but not limited to: agricultural crops, tree crops, crop by-products and residues; wood and paper manufacturing waste, including nontreated by-products of the wood manufacturing or pulping process, such as bark, wood chips, sawdust, and lignin in spent pulping liquors; forestry waste and residues; other vegetation waste, including landscape or right-of-way trimmings; algae; food waste; animal wastes and by-products (including fats, oils, greases and manure); biodegradable solid waste; and biologically derived methane gas.

(F) "Clean coal technology" means any technology that removes or has the design capability to remove criteria pollutants and carbon dioxide from an electric generating facility that uses coal as a fuel or feedstock as identified in the control plan requirements in paragraph (C) of rule 4901:1-41-03 of the Administrative Code.

(G) "Co-firing" means simultaneously using multiple fuels in the generation of electricity. In the event of co-firing, the proportion of energy input comprised of a renewable energy resource shall dictate the proportion of electricity output from the facility that can be considered a renewable energy resource.

(H) "Commission" means the public utilities commission of Ohio.

(I) "Deliverable into this state" means that the electricity originates from a facility within a state contiguous to Ohio. It may also include electricity originating from other locations, pending a demonstration that the electricity could be physically delivered to the state.

(J) "Demand response" has the meaning set forth in rule 4901:1-39-01 of the Administrative Code.

(K) "Demand-side management" has the meaning set forth in paragraph (F) of rule 4901:5-5-01 of the Administrative Code.

(L) "Distributed generation" means electricity production that is on-site and is connected to the electricity grid.

(M) "Double-counting" means utilizing renewable energy, renewable energy credits, or energy efficiency savings to do any of the following:

(1) Satisfy multiple Ohio state renewable energy requirements or such requirements for more than one state.

(2) Comply with both the energy efficiency and advanced energy statutory benchmarks.

(3) Support multiple voluntary product offerings.

(4) Substantiate multiple marketing claims.

(5) Some combination of these.

(N) "Electric generating facility" means a power plant or other facility where electricity is produced.

(O) "Electric services company" has the meaning set forth in division (A)(9) of section 4928.01 of the Revised Code.

(P) "Electric utility" has the meaning set forth in division (A)(11) of section 4928.01 of the Revised Code.

(Q) "Energy efficiency" has the meaning set forth in rule 4901:1-39-01 of the Administrative Code.

(R) "Energy storage" means a facility or technology that permits the storage of energy for future use as electricity.

(S) "Fuel cell" means a device that uses an electrochemical energy conversion process to produce electricity.

(T) "Geothermal energy" means hot water or steam extracted from geothermal reservoirs in the earth's crust and used for electricity generation..

(U) "Hydroelectric energy" means electricity generated by a hydroelectric facility as defined in division (A)(35) of section 4928.01 of the Revised Code.

(V) "Hydroelectric facility" has the meaning set forth in division (A)(35) of section 4928.01 of the Revised Code.

(W) "Mercantile customer" has the meaning set forth in division (A)(19) of section 4928.01 of the Revised Code.

(X) "MISO" means "Midwest Independent Transmission System Operator, Inc." or any successor regional transmission organization.

(Y) "Person" shall have the meaning set forth in division (A)(24) of section 4928.01 of the Revised Code.

(Z) "PJM" means "PJM Interconnection, LLC" or any successor regional transmission organization.

(AA) "Placed-in-service" means when a facility or technology becomes operational.

(BB) "Renewable energy credit" means the environmental attributes associated with one megawatt-hour of electricity generated by a renewable energy resource, except for electricity generated by facilities as described in paragraph (E) of rule 4901:1-40-04 of the Administrative Code.

(CC) "Renewable energy resource" has the meaning set forth in division (A)(35) of section 4928.01 of the Revised Code.

(DD) "Solar energy resources" means solar photovoltaic and/or solar thermal resources.

(EE) "Solar photovoltaic" means energy from devices which generate electricity directly from sunlight through the movement of electrons.

(FF) "Solar thermal" means the concentration of the sun's energy, typically through the use of lenses or mirrors, to drive a generator or engine to produce electricity.

(GG) "Solid wastes" has the meaning set forth in section 3734.01 of the Revised Code.

(HH) "Staff" means the commission staff or its authorized representative.

(II) "Standard service offer" means an electric utility offer to provide consumers, on a comparable and nondiscriminatory basis within its certified territory, all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service.

(JJ) "Wind energy" means electricity generated from wind turbines, windmills, or other technology that converts wind into electricity.

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Rule Amplifies: 4928.01 , 4928.64 , 4928.65

4901:1-40-02 Purpose and scope.

(A) This chapter addresses the implementation of the alternative energy portfolio standard, including the incorporation of renewable energy credits, as detailed in sections 4928.64 and 4928.65 of the Revised Code respectively. Parties affected by these alternative energy portfolio standard rules include all Ohio electric utilities and all electric services companies serving retail electric customers in Ohio. Any entities that do not serve Ohio retail electric customers shall not be required to comply with the terms of the alternative energy portfolio standard.

(B) The commission may, upon an application or a motion filed by a party, waive any requirement of this chapter, other than a requirement mandated by statute, for good cause shown.

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Statutory Authority: 4905.04 , 4905.06 , 4928.01 , 4928.02 , 4928.64 , 4928.65
Rule Amplifies: 4928.01 , 4928.02 , 4928.64 , 4928.65

4901:1-40-03 Requirements.

(A) All electric utilities and affected electric services companies shall ensure that, by the end of the year 2024 and each year thereafter, electricity from alternative energy resources equals at least twenty-five per cent of their retail electric sales in the state.

(1) Up to half of the electricity supplied from alternative energy resources may be generated from advanced energy resources.

(2) At least half of the electricity supplied from alternative energy resources shall be generated from renewable energy resources, including solar energy resources, in accordance with the following annual benchmarks:

Annual benchmarks for alternative energy resources generated from renewable and solar energy resources

By end of year	Renewable energy resources	Solar energy resources
2009	0.25%	0.004%
2010	0.50%	0.01%
2011	1.0%	0.03%
2012	1.5%	0.06%
2013	2.0%	0.09%
2014	2.5%	0.12%
2015	3.5%	0.15%
2016	4.5%	0.18%
2017	5.5%	0.22%
2018	6.5%	0.26%
2019	7.5%	0.30%
2020	8.5%	0.34%
2021	9.5%	0.38%
2022	10.5%	0.42%
2023	11.5%	0.46%
2024 and each year thereafter	12.5%	0.50%

(a) At least half of the annual renewable energy resources, including solar energy resources, shall be met through electricity generated by facilities located in this state. Facilities located in the state shall include a hydroelectric generating facility that is located on a river that is within or bordering this state, and wind turbines located in the state's territorial waters of Lake Erie.

(b) To qualify towards a benchmark, any electricity from renewable energy resources, including solar energy resources, that originates from outside of the state must be shown to be deliverable into this state.

(3) All costs incurred by an electric utility in complying with the requirements of section 4928.64 of the Revised Code, shall be avoidable by any consumer that has exercised choice of electricity supplier, during such time that a customer is served by an electric services company.

(B) The baseline for compliance with the alternative energy resource requirements shall be determined using the following methodologies:

(1) For electric utilities, the baseline shall be computed as an average of the three preceding calendar years of the total annual number of kilowatt-hours of electricity sold under its standard service offer to any and all retail electric customers whose electric load centers are served by that electric utility and are located within the electric utility's certified territory. The calculation of the baseline shall be based upon the average, annual, kilowatt-hour sales reported in that electric utility's three most recent forecast reports or reporting forms.

(2) For electric services companies, the baseline shall be computed as an average of the three preceding

calendar years of the total annual number of kilowatt-hours of electricity sold to any and all retail electric consumers served by the company in the state, based upon the kilowatt-hour sales in the electric services company's most recent quarterly market-monitoring reports or reporting forms.

(a) If an electric services company has not been continuously supplying Ohio retail electric customers during the preceding three calendar years, the baseline shall be computed as an average of annual sales data for all calendar years during the preceding three years in which the electric services company was serving retail customers.

(b) For an electric services company with no retail electric sales in the state during the preceding three calendar years, its initial baseline shall consist of a reasonable projection of its retail electric sales in the state for a full calendar year. Subsequent baselines shall consist of actual sales data, computed in a manner consistent with paragraph (B)(2)(a) of this rule.

(3) An electric utility or electric services company may file an application requesting a reduced baseline to reflect new economic growth in its service territory or service area. Any such application shall include a justification indicating why timely compliance based on the unadjusted baseline is not feasible, a schedule for achieving compliance based on its unadjusted baseline, quantification of a new change in the rate of economic growth, and a methodology for measuring economic activity, including objective measurement parameters and quantification methodologies.

(C) Beginning in the year 2010, each electric utility and electric services company annually shall file a plan for compliance with future annual advanced- and renewable-energy benchmarks, including solar, utilizing at least a ten-year planning horizon. This plan, to be filed by April fifteenth of each year, shall include at least the following items:

(1) Baseline for the current and future calendar years.

(2) Supply portfolio projection, including both generation fleet and power purchases.

(3) A description of the methodology used by the company to evaluate its compliance options.

(4) A discussion of any perceived impediments to achieving compliance with required benchmarks, as well as suggestions for addressing any such impediments.

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4901:1-40-04 Qualified resources.

(A) The following resources or technologies, if they have a placed-in-service date of January 1, 1998, or after, are qualified resources for meeting the renewable energy resource benchmarks:

(1) Solar photovoltaic or solar thermal energy.

(2) Wind energy.

(3) Hydroelectric energy.

(4) Geothermal energy.

(5) Solid waste energy derived from fractionalization, biological decomposition, or other process that does not principally involve combustion.

(6) Biomass energy.

(7) Energy from a fuel cell.

(8) A storage facility, if it complies with the following requirements:

(a) The electricity used to pump the resource into a storage reservoir must qualify as a renewable energy resource, or the equivalent renewable energy credits are obtained.

(b) The amount of energy that may qualify from a storage facility is the amount of electricity dispatched from the storage facility.

(9) Distributed generation system used by a customer to generate electricity from one of the resources or technologies listed in paragraphs (A)(1) to (A)(8) of this rule.

(10) A renewable energy resource created on or after January 1, 1998, by the modification or retrofit of any facility placed in service prior to January 1, 1998.

(B) The following resources or technologies, if they have a placed-in-service date of January 1, 1998, or after, are qualified resources for meeting the advanced energy resource benchmarks:

(1) Any modification to an electric generating facility that increases its generation output without increasing the facility's carbon dioxide emissions (tons per year) in comparison to its actual annual carbon dioxide emissions preceding the modification. In such an instance, it is the incremental increase in generation output that may be quantified and applied toward an advanced energy requirement.

(2) Any distributed generation system, designed primarily to meet the energy needs of the customer's facility that utilizes co-generation of electricity and thermal output simultaneously.

(3) Clean coal technology.

(4) Advanced nuclear energy technology, from:

(a) Advanced nuclear energy technology consisting of generation III technology as defined by the nuclear regulatory commission or other later technology.

(b) Significant improvements to existing facilities. In such an instance, it is the incremental increase in generation attributable to the improvement that may be quantified and applied toward an advanced energy requirement. Extension of the life of existing nuclear generation capacity shall not qualify as advanced nuclear energy technology.

(5) Energy from a fuel cell.

(6) Advanced solid waste or construction and demolition debris conversion technology that results in measurable greenhouse gas emission reductions.

(7) Demand-side management and energy efficiency, above and beyond that used to comply with any other regulatory standard or programs.

(C) The following new or existing mercantile customer-sited resources may be qualified resources for meeting electric utilities' annual, renewable- or advanced-energy resource benchmarks, as applicable, provided that it does not constitute double-counting for any other regulatory requirement and that the mercantile customer has committed the resource for integration into the electric utility's demand-response, energy efficiency, or peak-demand reduction programs pursuant to rule 4901:1-39-08 of the Administrative Code.

(1) Renewable energy resources from mercantile customers include the following:

(a) Electric generation equipment that uses a renewable energy resource and is owned or controlled by a mercantile customer.

(b) Any renewable energy resource of the mercantile customer that can be utilized effectively as part of an alternative energy resource plan of an electric utility and would otherwise qualify as a renewable energy resource if it were utilized directly by an electric utility.

(2) Advanced energy resources from mercantile customers include the following:

(a) A resource that improves the relationship between real and reactive power.

(b) A mercantile customer-owned or controlled resource that makes efficient use of waste heat or other thermal capabilities.

(c) Storage technology that allows a mercantile customer more flexibility to modify its demand or load and usage characteristics.

(d) Electric generation equipment owned or controlled by a mercantile customer that uses an advanced energy resource.

(e) Any advanced energy resource of the mercantile customer that can be utilized effectively as part of an advanced energy resource plan of an electric utility and would otherwise qualify as an advanced energy resource if it were utilized directly by an electric utility.

(D) An electric utility or electric services company may use renewable energy credits (REC) to satisfy all or part of a renewable energy resource benchmark, including a solar energy resource benchmark.

(1) To be eligible for use towards satisfying a benchmark, a REC must originate from a facility that meets the definition of a renewable energy resource, including solar energy resources, and be measured by a utility-grade meter in compliance with paragraph B of rule 4901:1-10-05 of the Administrative Code, for facilities with generating capacity of more than six kilowatts. Such facilities could include a mercantile customer-sited resource that is not committed for integration into an electric utility's demand-response, energy efficiency, or peak-demand reduction program pursuant to rule 4901:1-39-08 of the Administrative Code but that otherwise qualifies under the terms of paragraph (A) of this rule.

(2) To use RECs as a means of achieving partial or complete compliance, an electric utility or electric services company must be a registered member in good standing of at least one of the following:

(a) The PJM's generation attributes tracking system.

(b) The MISO's renewable energy tracking system.

(c) Another credible tracking system approved for use by the commission.

(3) A REC may be used for compliance any time in the five calendar years following the date of its initial purchase or acquisition.

(4) Double counting is prohibited.

(5) The RECs must be associated with electricity that was generated no earlier than July 31, 2008.

(E) For a generating facility of seventy-five megawatts or greater that is situated within this state and has committed by December 31, 2009, to modify or retrofit its generating unit or units to enable the facility to generate principally from biomass energy by June 30, 2013, the number of RECs produced by each megawatt-hour of electricity generated principally from biomass energy shall equal the actual percentage of biomass feedstock heat input used to generate such megawatt-hour multiplied by the quotient obtained by dividing the then existing unit dollar amount used to determine a renewable energy compliance payment as provided under division (C)(2)(b) of section 4928.64 of the Revised Code, by the then existing market value of one REC, but such megawatt-hour shall not equal less than one credit.

(F) An entity seeking resource qualification shall file an application for certification of its resources or technologies, upon such forms as may be prescribed by the commission. The application shall include a determination of deliverability to the state in accordance with paragraph (I) of rule 4901:1-40-01 of the Administrative Code.

(1) Any interested person may file a motion to intervene and file comments and objections to any application filed under this rule within twenty days of the date of the filing of the application.

(2) The commission may approve, suspend, or deny an application within sixty days of it being filed. If the commission does not act within sixty days, the application is deemed automatically approved on the sixty-first day after the date filed.

(3) If the commission suspends the application, the applicant shall be notified of the reasons for such suspension and may be directed to furnish additional information. The commission may act to approve or deny a suspended application within ninety days of the date that the application was suspended.

(4) Upon commission approval, the applicant shall receive notification of approval and a numbered certificate where applicable. The commission shall provide this certificate number to the appropriate attribute tracking system.

(5) Representatives of certified facilities must notify the commission within thirty days of any material changes in information previously submitted to the commission during the certification process. Failure to do so may result in revocation of certification status.

(6) Certification of a resource or technology shall not predetermine compliance with annual benchmarks, and does not constitute any commission position regarding cost recovery.

(G) At its discretion, the commission may classify any new technology or additional resource as an advanced- or renewable-energy resource. Any interested person may request a hearing on such classification.

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4901:1-40-05 Annual status reports and compliance reviews.

(A) Unless otherwise ordered by the commission, each electric utility and electric services company shall file by April fifteenth of each year, on such forms as may be published by the commission, an annual alternative energy portfolio status report analyzing all activities undertaken in the previous calendar year to demonstrate how the applicable alternative energy portfolio benchmarks and planning requirements have or will be met. Staff shall conduct annual compliance reviews with regard to the benchmarks under the alternative energy portfolio standard.

(1) Beginning in the year 2010, the annual review will include compliance with the most recent applicable renewable- and solar-energy resource benchmark.

(2) Beginning in the year 2025, the annual review will include compliance with the most recent applicable advanced energy resource benchmark.

(3) The annual compliance reviews shall consider any under-compliance an electric utility or electric services

company asserts is outside its control, including but not limited to, the following:

(a) Weather-related causes.

(b) Equipment shortages for renewable or advanced energy resources.

(c) Resource shortages for renewable or advanced energy resources.

(B) Any person may file comments regarding the electric utility's or electric services company's alternative energy portfolio status report within thirty days of the filing of such report.

(C) Staff shall review each electric utility's or electric services company's alternative energy portfolio status report and any timely filed comments, and file its findings and recommendations and any proposed modifications thereto.

(D) The commission may schedule a hearing on the alternative energy portfolio status report.

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Rule Amplifies: 4928.64 , 4928.65

4901:1-40-06 Force majeure.

An electric utility or electric services company may seek a force majeure determination from the commission for all or part of a minimum renewable- or solar-energy benchmark.

(A) A decision on a request for a force majeure determination will be rendered within ninety days of an electric utility or electric services company filing a request for such determination. The process and timeframes for such a determination shall be set by entry of the commission, the legal director, deputy legal director, or attorney examiner.

(1) At the time of requesting such a determination from the commission, an electric utility or electric services company shall demonstrate that it pursued all reasonable compliance options including, but not limited to, renewable energy credit (REC) solicitations, REC banking, and long-term contracts.

(2) The request shall include an assessment of the availability of qualified in-state resources, as well as qualified resources within the territories of PJM and the MISO.

(B) If the commission determines that force majeure conditions exist, it may modify that compliance obligation of the electric utility or electric services company, as it considers appropriate to accommodate the finding.

(1) Such modification does not automatically reduce future-year obligations.

(2) The commission retains the right to increase a future year's compliance obligation by the amount of any under compliance in a previous year that is attributed to a force majeure determination.

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Rule Amplifies: 4928.64

4901:1-40-07 Cost cap.

(A) An electric utility or electric services company may file an application requesting a determination from the commission that its reasonably expected cost of compliance with an advanced energy resource benchmark would exceed its reasonably expected cost of generation to customers by three per cent or more. The process and timeframes for such a determination shall be set by entry of the commission, the legal director, deputy legal director, or attorney examiner.

(1) The burden of proof for substantiating such a claim shall remain with the electric utility or electric services company.

(2) An electric utility or electric services company shall pursue all reasonable compliance options prior to requesting such a determination from the commission.

(3) In the case that the commission makes such a determination, the electric utility or electric services company may not be required to fully comply with that specific benchmark.

(B) An electric utility or electric services company may file an application requesting a determination from the commission that its reasonably expected cost of compliance with a renewable energy resource benchmark, including a solar energy resource benchmark, would exceed its reasonably expected cost of generation to customers by three per cent or more. The process and timeframes for such a determination shall be set by entry of the commission, the legal director, deputy legal director, or attorney examiner.

(1) The burden of proof for substantiating such a claim shall remain with the electric utility or electric services company.

(2) An electric utility or electric services company shall pursue all reasonable compliance options prior to requesting such a determination from the commission.

(3) In the case that the commission makes such a determination, the electric utility or electric services company may not be required to fully comply with that specific benchmark.

(C) Calculations involving a three per cent cost cap shall consist of comparing the total expected cost of generation to customers of an electric utility or electric services company, while satisfying an alternative energy portfolio standard requirement, to the total expected cost of generation to customers of the electric utility or electric services company without satisfying that alternative energy portfolio standard requirement.

(D) Any costs included in a commission-approved unavoidable surcharge for construction or environmental expenditures of generation resources shall be excluded from consideration as a cost of compliance under the terms of the alternative energy portfolio standard and therefore, would not count against the applicable cost cap. Such costs should, however, be included in the calculation of the total expected cost of generation to customers described in paragraph (C) of this rule.

(E) If the commission makes a determination that a three per cent provision is triggered, the electric utility or electric services company shall comply with each benchmark up to the point that the three per cent increment would be reached for each benchmark.

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4901:1-40-08 Compliance payments.

(A) Any electric utility or electric services company that does not achieve an annual renewable energy resource benchmark, including a solar benchmark, shall remit a compliance payment based on the amount of noncompliance rounded up to the next megawatt hour (MWh), unless the commission has identified the existence of force majeure conditions or the commission has determined that the three per cent cost-cap provision would be exceeded in the event of full compliance.

(1) The required payment for noncompliance with any solar energy resource benchmark shall be calculated by quantifying the level of noncompliance, rounded to the next MWh, and multiplying this figure by the per MWh amount in the table below.

Solar energy resources - compliance payment

Year	Payment per MWh
2009	$450
2010 and 2011	$400
2012 and 2013	$350
2014 and 2015	$300
2016 and 2017	$250
2018 and 2019	$200
2020 and 2021	$150
2022 and 2023	$100
2024 and beyond	$50

(2) The required payment for noncompliance with any renewable energy resource benchmark, excluding solar, shall be calculated by quantifying the level of noncompliance, rounded to the next MWh, and multiplying this figure by an amount determined by the commission.

(a) The per MWh payment for renewable energy resources for the year 2009 is forty-five dollars.

(b) Beginning in the year 2010, the per MWh payment for renewable energy resources will be adjusted annually to reflect the annual change to the consumer price index as defined in section 101.27 of the Revised Code. Such adjustment shall be performed by staff no later than June first of each calendar year. This annual adjustment shall be calculated using the following formula:

= ((CPIYR2/CPIYR1) * current per MWh payment) (c) In no event shall the compliance payment for renewable energy resources be less than forty-five dollars per MWh.

(3) At least annually, the staff shall conduct a review of the renewable energy resource market, including solar, both within this state and within the regional transmission systems active in the state. The results of this review shall be used to determine if changes to the solar- or renewable-energy compliance payments are warranted, as follows:

(a) The commission may increase compliance payments if needed to ensure that electric utilities and electric services companies are not using the payments in lieu of acquiring or producing energy or RECs from qualified renewable resources, including solar.

(b) Any recommendation to reduce the compliance payments shall be presented to the general assembly.

(B) Any compliance payment shall be submitted to the commission for deposit to the credit of the advanced energy fund. All compliance payments shall be delivered to the commission within thirty days of the imposition of any compliance payment requirement.

(C) Compliance payments shall be subject to such collection and enforcement procedures as apply to the collection of a forfeiture under sections 4905.55 to 4905.60 and 4905.64 of the Revised Code.

(D) Any electric utility or electric services company found to be liable for a compliance payment is prohibited from passing compliance payments on to consumers. In the event that a compliance payment is required, an electric utility or electric services company shall submit an attestation, signed by a company officer or designee, indicating that it will not seek to recover the specific compliance payment from consumers. Such attestation shall be submitted to staff within thirty days of the imposition of any compliance payment requirement.

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4901:1-40-09 Annual report.

(A) Pursuant to division (D)(1) of section 4928.64 of the Revised Code, an annual report shall be submitted to the general assembly addressing at least the following topics:

(1) The compliance status of electric utilities and electric services companies with respect to the advanced- and renewable-energy resource benchmarks.

(2) Suggested strategies for electric utility and electric services company compliance.

(3) Suggested strategies for encouraging the use of alternative energy resources in supplying this state's electricity needs in a manner that considers:

(a) Available technology.

(b) Costs.

(c) Job creation.

(d) Economic impacts.

(B) The report shall be submitted in accordance with section 101.68 of the Revised Code.

(C) Prior to its submission to the general assembly, the report will be issued for public comment by interested persons for thirty days, unless otherwise ordered by the commission. The process and timeframes for soliciting public comment shall be set by entry of the commission, the legal director, deputy director, or attorney examiner.

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Appendix N:

ORC Chapter 4928: Competitive Retail Electric Service

Chapter 4928: COMPETITIVE RETAIL ELECTRIC SERVICE

4928.01 [Effective Until 9/12/2014] Competitive retail electric service definitions.

(A) As used in this chapter:

(1) "Ancillary service" means any function necessary to the provision of electric transmission or distribution service to a retail customer and includes, but is not limited to, scheduling, system control, and dispatch services; reactive supply from generation resources and voltage control service; reactive supply from transmission resources service; regulation service; frequency response service; energy imbalance service; operating reserve-spinning reserve service; operating reserve-supplemental reserve service; load following; back-up supply service; real-power loss replacement service; dynamic scheduling; system black start capability; and network stability service.

(2) "Billing and collection agent" means a fully independent agent, not affiliated with or otherwise controlled by an electric utility, electric services company, electric cooperative, or governmental aggregator subject to certification under section 4928.08 of the Revised Code, to the extent that the agent is under contract with such utility, company, cooperative, or aggregator solely to provide billing and collection for retail electric service on behalf of the utility company, cooperative, or aggregator.

(3) "Certified territory" means the certified territory established for an electric supplier under sections 4933.81 to 4933.90 of the Revised Code.

(4) "Competitive retail electric service" means a component of retail electric service that is competitive as provided under division (B) of this section.

(5) "Electric cooperative" means a not-for-profit electric light company that both is or has been financed in whole or in part under the "Rural Electrification Act of 1936," 49 Stat. 1363, 7 U.S.C. 901 , and owns or operates facilities in this state to generate, transmit, or distribute electricity, or a not-for-profit successor of such company.

(6) "Electric distribution utility" means an electric utility that supplies at least retail electric distribution service.

(7) "Electric light company" has the same meaning as in section 4905.03 of the Revised Code and includes an electric services company, but excludes any self-generator to the extent that it consumes electricity it so produces, sells that electricity for resale, or obtains electricity from a generating facility it hosts on its premises.

(8) "Electric load center" has the same meaning as in section 4933.81 of the Revised Code.

(9) "Electric services company" means an electric light company that is engaged on a for-profit or not-for-profit basis in the business of supplying or arranging for the supply of only a competitive retail electric service in this state. "Electric services company" includes a power marketer, power broker, aggregator, or independent power producer but excludes an electric cooperative, municipal electric utility, governmental aggregator, or billing and collection agent.

(10) "Electric supplier" has the same meaning as in section 4933.81 of the Revised Code.

(11) "Electric utility" means an electric light company that has a certified territory and is engaged on a for-profit basis either in the business of supplying a noncompetitive retail electric service in this state or in the

businesses of supplying both a noncompetitive and a competitive retail electric service in this state. "Electric utility" excludes a municipal electric utility or a billing and collection agent.

(12) "Firm electric service" means electric service other than nonfirm electric service.

(13) "Governmental aggregator" means a legislative authority of a municipal corporation, a board of township trustees, or a board of county commissioners acting as an aggregator for the provision of a competitive retail electric service under authority conferred under section 4928.20 of the Revised Code.

(14) A person acts "knowingly," regardless of the person's purpose, when the person is aware that the person's conduct will probably cause a certain result or will probably be of a certain nature. A person has knowledge of circumstances when the person is aware that such circumstances probably exist.

(15) "Level of funding for low-income customer energy efficiency programs provided through electric utility rates" means the level of funds specifically included in an electric utility's rates on October 5, 1999, pursuant to an order of the public utilities commission issued under Chapter 4905. or 4909. of the Revised Code and in effect on October 4, 1999, for the purpose of improving the energy efficiency of housing for the utility's low-income customers. The term excludes the level of any such funds committed to a specific nonprofit organization or organizations pursuant to a stipulation or contract.

(16) "Low-income customer assistance programs" means the percentage of income payment plan program, the home energy assistance program, the home weatherization assistance program, and the targeted energy efficiency and weatherization program.

(17) "Market development period" for an electric utility means the period of time beginning on the starting date of competitive retail electric service and ending on the applicable date for that utility as specified in section 4928.40 of the Revised Code, irrespective of whether the utility applies to receive transition revenues under this chapter.

(18) "Market power" means the ability to impose on customers a sustained price for a product or service above the price that would prevail in a competitive market.

(19) "Mercantile customer" means a commercial or industrial customer if the electricity consumed is for nonresidential use and the customer consumes more than seven hundred thousand kilowatt hours per year or is part of a national account involving multiple facilities in one or more states.

(20) "Municipal electric utility" means a municipal corporation that owns or operates facilities to generate, transmit, or distribute electricity.

(21) "Noncompetitive retail electric service" means a component of retail electric service that is noncompetitive as provided under division (B) of this section.

(22) "Nonfirm electric service" means electric service provided pursuant to a schedule filed under section 4905.30 of the Revised Code or pursuant to an arrangement under section 4905.31 of the Revised Code, which schedule or arrangement includes conditions that may require the customer to curtail or interrupt electric usage during nonemergency circumstances upon notification by an electric utility.

(23) "Percentage of income payment plan arrears" means funds eligible for collection through the percentage of income payment plan rider, but uncollected as of July 1, 2000.

(24) "Person" has the same meaning as in section 1.59 of the Revised Code.

(25) "Advanced energy project" means any technologies, products, activities, or management practices or strategies that facilitate the generation or use of electricity or energy and that reduce or support the reduction of energy consumption or support the production of clean, renewable energy for industrial, distribution, commercial, institutional, governmental, research, not-for-profit, or residential energy users, including, but not limited to, advanced energy resources and renewable energy resources. "Advanced energy project" also includes any project described in division (A), (B), or (C) of section 4928.621 of the Revised Code.

(26) "Regulatory assets" means the unamortized net regulatory assets that are capitalized or deferred on the regulatory books of the electric utility, pursuant to an order or practice of the public utilities commission or pursuant to generally accepted accounting principles as a result of a prior commission rate-making decision, and that would otherwise have been charged to expense as incurred or would not have been capitalized or otherwise deferred for future regulatory consideration absent commission action. "Regulatory assets" includes, but is not limited to, all deferred demand-side management costs; all deferred percentage of income payment plan arrears; post-in-service capitalized charges and assets recognized in connection with statement of financial accounting standards no. 109 (receivables from customers for income taxes); future nuclear decommissioning costs and fuel disposal costs as those costs have been determined by the commission in the electric utility's most recent rate or accounting application proceeding addressing such costs; the undepreciated costs of safety and radiation control equipment on nuclear generating plants owned or leased by an electric utility; and fuel costs currently deferred pursuant to the terms of one or more settlement agreements approved by the commission.

(27) "Retail electric service" means any service involved in supplying or arranging for the supply of electricity to ultimate consumers in this state, from the point of generation to the point of consumption. For the purposes of this chapter, retail electric service includes one or more of the following "service components": generation service, aggregation service, power marketing service, power brokerage service, transmission service, distribution service, ancillary service, metering service, and billing and collection service.

(28) "Starting date of competitive retail electric service" means January 1, 2001.

(29) "Customer-generator" means a user of a net metering system.

(30) "Net metering" means measuring the difference in an applicable billing period between the electricity supplied by an electric service provider and the electricity generated by a customer-generator that is fed back to the electric service provider.

(31) "Net metering system" means a facility for the production of electrical energy that does all of the following:

(a) Uses as its fuel either solar, wind, biomass, landfill gas, or hydropower, or uses a microturbine or a fuel cell;

(b) Is located on a customer-generator's premises;

(c) Operates in parallel with the electric utility's transmission and distribution facilities;

(d) Is intended primarily to offset part or all of the customer-generator's requirements for electricity.

(32) "Self-generator" means an entity in this state that owns or hosts on its premises an electric generation facility that produces electricity primarily for the owner's consumption and that may provide

any such excess electricity to another entity, whether the facility is installed or operated by the owner or by an agent under a contract.

(33) "Rate plan" means the standard service offer in effect on the effective date of the amendment of this section by S.B. 221 of the 127th general assembly, July 31, 2008.

(34) "Advanced energy resource" means any of the following:

(a) Any method or any modification or replacement of any property, process, device, structure, or equipment that increases the generation output of an electric generating facility to the extent such efficiency is achieved without additional carbon dioxide emissions by that facility;

(b) Any distributed generation system consisting of customer cogeneration technology;

(c) Clean coal technology that includes a carbon-based product that is chemically altered before combustion to demonstrate a reduction, as expressed as ash, in emissions of nitrous oxide, mercury, arsenic, chlorine, sulfur dioxide, or sulfur trioxide in accordance with the American society of testing and materials standard D1757A or a reduction of metal oxide emissions in accordance with standard D5142 of that society, or clean coal 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;

(d) Advanced nuclear energy technology consisting of generation III technology as defined by the nuclear regulatory commission; other, later technology; or significant improvements to existing facilities;

(e) Any fuel cell used in the generation of electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid oxide fuel cell;

(f) Advanced solid waste or construction and demolition debris conversion technology, including, but not limited to, advanced stoker technology, and advanced fluidized bed gasification technology, that results in measurable greenhouse gas emissions reductions as calculated pursuant to the United States environmental protection agency's waste reduction model (WARM) ;

(g) Demand-side management and any energy efficiency improvement;

(h) Any new, retrofitted, refueled, or repowered generating facility located in Ohio, including a simple or combined-cycle natural gas generating facility or a generating facility that uses biomass, coal, modular nuclear, or any other fuel as its input;

(i) Any uprated capacity of an existing electric generating facility if the uprated capacity results from the deployment of advanced technology.

"Advanced energy resource" does not include a waste energy recovery system that is, or has been, included in an energy efficiency program of an electric distribution utility pursuant to requirements under section 4928.66 of the Revised Code.

(35) "Air contaminant source" has the same meaning as in section 3704.01 of the Revised Code.

(36) "Cogeneration technology" means technology that produces electricity and useful thermal output simultaneously.

(37)

(a) "Renewable energy resource" means any of the following:

(i) Solar photovoltaic or solar thermal energy ;

(ii) Wind energy ;

(iii) Power produced by a hydroelectric facility ;

(iv) Geothermal energy ;

(v) Fuel derived from solid wastes, as defined in section 3734.01 of the Revised Code, through fractionation, biological decomposition, or other process that does not principally involve combustion ;

(vi) Biomass energy ;

(vii) Energy produced by cogeneration technology that is placed into service on or before December 31, 2015, and for which more than ninety per cent of the total annual energy input is from combustion of a waste or byproduct gas from an air contaminant source in this state, which source has been in operation since on or before January 1, 1985, provided that the cogeneration technology is a part of a facility located in a county having a population of more than three hundred sixty-five thousand but less than three hundred seventy thousand according to the most recent federal decennial census ;

(viii) Biologically derived methane gas ;

(ix) Energy derived from nontreated by-products of the pulping process or wood manufacturing process, including bark, wood chips, sawdust, and lignin in spent pulping liquors.

"Renewable energy resource" includes, but is not limited to, any fuel cell used in the generation of electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid oxide fuel cell; wind turbine located in the state's territorial waters of Lake Erie; methane gas emitted from an abandoned coal mine; waste energy recovery system placed into service or retrofitted on or after the effective date of the amendment of this section by S.B. 315 of the 129th general assembly, except that a waste energy recovery system described in division (A)(38)(b) of this section may be included only if it was placed into service between January 1, 2002, and December 31, 2004; storage facility that will promote the better utilization of a renewable energy resource ; or distributed generation system used by a customer to generate electricity from any such energy.

"Renewable energy resource" does not include a waste energy recovery system that is, or was, on or after January 1, 2012, included in an energy efficiency program of an electric distribution utility pursuant to requirements under section 4928.66 of the Revised Code.

(b) As used in division (A)(37) of this section, "hydroelectric facility" means a hydroelectric generating facility that is located at a dam on a river, or on any water discharged to a river, that is within or bordering this state or within or bordering an adjoining state and meets all of the following standards:

(i) The facility provides for river flows that are not detrimental for fish, wildlife, and water quality, including seasonal flow fluctuations as defined by the applicable licensing agency for the facility.

(ii) The facility demonstrates that it complies with the water quality standards of this state, which compliance may consist of certification under Section 401 of the "Clean Water Act of 1977," 91 Stat. 1598, 1599, 33 U.S.C. 1341 , and demonstrates that it has not contributed to a finding by this state that the river has impaired water quality under Section 303(d) of the "Clean Water Act of 1977," 114 Stat. 870, 33 U.S.C. 1313 .

(iii) The facility complies with mandatory prescriptions regarding fish passage as required by the federal energy regulatory commission license issued for the project, regarding fish protection for riverine, anadromous, and catadromous fish.

(iv) The facility complies with the recommendations of the Ohio environmental protection agency and with the terms of its federal energy regulatory commission license regarding watershed protection, mitigation, or enhancement, to the extent of each agency's respective jurisdiction over the facility.

(v) The facility complies with provisions of the "Endangered Species Act of 1973," 87 Stat. 884, 16 U.S.C. 1531 to 1544 , as amended.

(vi) The facility does not harm cultural resources of the area. This can be shown through compliance with the terms of its federal energy regulatory commission license or, if the facility is not regulated by that commission, through development of a plan approved by the Ohio historic preservation office, to the extent it has jurisdiction over the facility.

(vii) The facility complies with the terms of its federal energy regulatory commission license or exemption that are related to recreational access, accommodation, and facilities or, if the facility is not regulated by that commission, the facility complies with similar requirements as are recommended by resource agencies, to the extent they have jurisdiction over the facility; and the facility provides access to water to the public without fee or charge.

(viii) The facility is not recommended for removal by any federal agency or agency of any state, to the extent the particular agency has jurisdiction over the facility.

(38) "Waste energy recovery system" means either of the following:

(a) A facility that generates electricity through the conversion of energy from either of the following:

(i) Exhaust heat from engines or manufacturing, industrial, commercial, or institutional sites, except for exhaust heat from a facility whose primary purpose is the generation of electricity;

(ii) Reduction of pressure in gas pipelines before gas is distributed through the pipeline, provided that the conversion of energy to electricity is achieved without using additional fossil fuels.

(b) A facility at a state institution of higher education as defined in section 3345.011 of the Revised Code that recovers waste heat from electricity-producing engines or combustion turbines and that simultaneously uses the recovered heat to produce steam, provided that the facility was placed into service between January 1, 2002, and December 31, 2004.

(39) "Smart grid" means capital improvements to an electric distribution utility's distribution infrastructure that improve reliability, efficiency, resiliency, or reduce energy demand or use, including, but not limited to, advanced metering and automation of system functions.

(40) "Combined heat and power system" means the coproduction of electricity and useful thermal energy from the same fuel source designed to achieve thermal-efficiency levels of at least sixty per cent, with at least twenty per cent of the system's total useful energy in the form of thermal energy.

(B) For the purposes of this chapter, a retail electric service component shall be deemed a competitive retail electric service if the service component is competitive pursuant to a declaration by a provision of the Revised Code or pursuant to an order of the public utilities commission authorized under division (A) of section 4928.04 of the Revised Code. Otherwise, the service component shall be deemed a noncompetitive retail electric service.

Cite as R.C. § 4928.01

Amended by 129th General AssemblyFile No.125, SB 315, §101.01, eff. 9/10/2012.

Amended by 128th General AssemblyFile No.47, SB 181, §1, eff. 9/13/2010.

Amended by 128th General AssemblyFile No.48, SB 232, §1, eff. 6/17/2010.

Amended by 128th General AssemblyFile No.9, HB 1, §101.01, eff. 10/16/2009.

Effective Date: 10-05-1999; 01-04-2007; 2008 SB221 07-31-2008

4928.01 [Effective 9/12/2014] Competitive retail electric service definitions.

(A) As used in this chapter:

(1) "Ancillary service" means any function necessary to the provision of electric transmission or distribution service to a retail customer and includes, but is not limited to, scheduling, system control, and dispatch services; reactive supply from generation resources and voltage control service; reactive supply from transmission resources service; regulation service; frequency response service; energy imbalance service; operating reserve-spinning reserve service; operating reserve-supplemental reserve service; load following; back-up supply service; real-power loss replacement service; dynamic scheduling; system black start capability; and network stability service.

(2) "Billing and collection agent" means a fully independent agent, not affiliated with or otherwise controlled by an electric utility, electric services company, electric cooperative, or governmental aggregator subject to certification under section 4928.08 of the Revised Code, to the extent that the agent is under contract with such utility, company, cooperative, or aggregator solely to provide billing and collection for retail electric service on behalf of the utility company, cooperative, or aggregator.

(3) "Certified territory" means the certified territory established for an electric supplier under sections 4933.81 to 4933.90 of the Revised Code.

(4) "Competitive retail electric service" means a component of retail electric service that is competitive as provided under division (B) of this section.

(5) "Electric cooperative" means a not-for-profit electric light company that both is or has been financed in whole or in part under the "Rural Electrification Act of 1936," 49 Stat. 1363, 7 U.S.C. 901, and owns or operates facilities in this state to generate, transmit, or distribute electricity, or a not-for-profit successor of such company.

(6) "Electric distribution utility" means an electric utility that supplies at least retail electric distribution service.

(7) "Electric light company" has the same meaning as in section 4905.03 of the Revised Code and includes an electric services company, but excludes any self-generator to the extent that it consumes electricity it so produces, sells that electricity for resale, or obtains electricity from a generating facility it hosts on its premises.

(8) "Electric load center" has the same meaning as in section 4933.81 of the Revised Code.

(9) "Electric services company" means an electric light company that is engaged on a for-profit or not-for-profit basis in the business of supplying or arranging for the supply of only a competitive retail electric service in this state. "Electric services company" includes a power marketer, power broker, aggregator, or independent power producer but excludes an electric cooperative, municipal electric utility, governmental aggregator, or billing and collection agent.

(10) "Electric supplier" has the same meaning as in section 4933.81 of the Revised Code.

(11) "Electric utility" means an electric light company that has a certified territory and is engaged on a for-profit basis either in the business of supplying a noncompetitive retail electric service in this state or in the businesses of supplying both a noncompetitive and a competitive retail electric service in this state. "Electric utility" excludes a municipal electric utility or a billing and collection agent.

(12) "Firm electric service" means electric service other than nonfirm electric service.

(13) "Governmental aggregator" means a legislative authority of a municipal corporation, a board of township trustees, or a board of county commissioners acting as an aggregator for the provision of a competitive retail electric service under authority conferred under section 4928.20 of the Revised Code.

(14) A person acts "knowingly," regardless of the person's purpose, when the person is aware that the person's conduct will probably cause a certain result or will probably be of a certain nature. A person has knowledge of circumstances when the person is aware that such circumstances probably exist.

(15) "Level of funding for low-income customer energy efficiency programs provided through electric utility rates" means the level of funds specifically included in an electric utility's rates on October 5, 1999, pursuant to an order of the public utilities commission issued under Chapter 4905. or 4909. of the Revised Code and in effect on October 4, 1999, for the purpose of improving the energy efficiency of housing for the utility's low-income customers. The term excludes the level of any such funds committed to a specific nonprofit organization or organizations pursuant to a stipulation or contract.

(16) "Low-income customer assistance programs" means the percentage of income payment plan program, the home energy assistance program, the home weatherization assistance program, and the targeted energy efficiency and weatherization program.

(17) "Market development period" for an electric utility means the period of time beginning on the starting date of competitive retail electric service and ending on the applicable date for that utility as specified in section 4928.40 of the Revised Code, irrespective of whether the utility applies to receive transition revenues under this chapter.

(18) "Market power" means the ability to impose on customers a sustained price for a product or service above the price that would prevail in a competitive market.

(19) "Mercantile customer" means a commercial or industrial customer if the electricity consumed is for nonresidential use and the customer consumes more than seven hundred thousand kilowatt hours per year or is part of a national account involving multiple facilities in one or more states.

(20) "Municipal electric utility" means a municipal corporation that owns or operates facilities to generate, transmit, or distribute electricity.

(21) "Noncompetitive retail electric service" means a component of retail electric service that is

noncompetitive as provided under division (B) of this section.

(22) "Nonfirm electric service" means electric service provided pursuant to a schedule filed under section 4905.30 of the Revised Code or pursuant to an arrangement under section 4905.31 of the Revised Code, which schedule or arrangement includes conditions that may require the customer to curtail or interrupt electric usage during nonemergency circumstances upon notification by an electric utility.

(23) "Percentage of income payment plan arrears" means funds eligible for collection through the percentage of income payment plan rider, but uncollected as of July 1, 2000.

(24) "Person" has the same meaning as in section 1.59 of the Revised Code.

(25) "Advanced energy project" means any technologies, products, activities, or management practices or strategies that facilitate the generation or use of electricity or energy and that reduce or support the reduction of energy consumption or support the production of clean, renewable energy for industrial, distribution, commercial, institutional, governmental, research, not-for-profit, or residential energy users, including, but not limited to, advanced energy resources and renewable energy resources. "Advanced energy project" also includes any project described in division (A), (B), or (C) of section 4928.621 of the Revised Code.

(26) "Regulatory assets" means the unamortized net regulatory assets that are capitalized or deferred on the regulatory books of the electric utility, pursuant to an order or practice of the public utilities commission or pursuant to generally accepted accounting principles as a result of a prior commission rate-making decision, and that would otherwise have been charged to expense as incurred or would not have been capitalized or otherwise deferred for future regulatory consideration absent commission action. "Regulatory assets" includes, but is not limited to, all deferred demand-side management costs; all deferred percentage of income payment plan arrears; post-in-service capitalized charges and assets recognized in connection with statement of financial accounting standards no. 109 (receivables from customers for income taxes); future nuclear decommissioning costs and fuel disposal costs as those costs have been determined by the commission in the electric utility's most recent rate or accounting application proceeding addressing such costs; the undepreciated costs of safety and radiation control equipment on nuclear generating plants owned or leased by an electric utility; and fuel costs currently deferred pursuant to the terms of one or more settlement agreements approved by the commission.

(27) "Retail electric service" means any service involved in supplying or arranging for the supply of electricity to ultimate consumers in this state, from the point of generation to the point of consumption. For the purposes of this chapter, retail electric service includes one or more of the following "service components": generation service, aggregation service, power marketing service, power brokerage service, transmission service, distribution service, ancillary service, metering service, and billing and collection service.

(28) "Starting date of competitive retail electric service" means January 1, 2001.

(29) "Customer-generator" means a user of a net metering system.

(30) "Net metering" means measuring the difference in an applicable billing period between the electricity supplied by an electric service provider and the electricity generated by a customer-generator that is fed back to the electric service provider.

(31) "Net metering system" means a facility for the production of electrical energy that does all of the following:

(a) Uses as its fuel either solar, wind, biomass, landfill gas, or hydropower, or uses a microturbine or a fuel cell;

(b) Is located on a customer-generator's premises;

(c) Operates in parallel with the electric utility's transmission and distribution facilities;

(d) Is intended primarily to offset part or all of the customer-generator's requirements for electricity.

(32) "Self-generator" means an entity in this state that owns or hosts on its premises an electric generation facility that produces electricity primarily for the owner's consumption and that may provide any such excess electricity to another entity, whether the facility is installed or operated by the owner or by an agent under a contract.

(33) "Rate plan" means the standard service offer in effect on the effective date of the amendment of this section by S.B. 221 of the 127th general assembly, July 31, 2008.

(34) "Advanced energy resource" means any of the following:

(a) Any method or any modification or replacement of any property, process, device, structure, or equipment that increases the generation output of an electric generating facility to the extent such efficiency is achieved without additional carbon dioxide emissions by that facility;

(b) Any distributed generation system consisting of customer cogeneration technology;

(c) Clean coal technology that includes a carbon-based product that is chemically altered before combustion to demonstrate a reduction, as expressed as ash, in emissions of nitrous oxide, mercury, arsenic, chlorine, sulfur dioxide, or sulfur trioxide in accordance with the American society of testing and materials standard D1757A or a reduction of metal oxide emissions in accordance with standard D5142 of that society, or clean coal 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;

(d) Advanced nuclear energy technology consisting of generation III technology as defined by the nuclear regulatory commission; other, later technology; or significant improvements to existing facilities;

(e) Any fuel cell used in the generation of electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid oxide fuel cell;

(f) Advanced solid waste or construction and demolition debris conversion technology, including, but not limited to, advanced stoker technology, and advanced fluidized bed gasification technology, that results in measurable greenhouse gas emissions reductions as calculated pursuant to the United States environmental protection agency's waste reduction model (WARM);

(g) Demand-side management and any energy efficiency improvement;

(h) Any new, retrofitted, refueled, or repowered generating facility located in Ohio, including a simple or combined-cycle natural gas generating facility or a generating facility that uses biomass, coal, modular nuclear, or any other fuel as its input;

(i) Any uprated capacity of an existing electric generating facility if the uprated capacity results from the deployment of advanced technology.

"Advanced energy resource" does not include a waste energy recovery system that is, or has been, included in an energy efficiency program of an electric distribution utility pursuant to requirements under section 4928.66 of the Revised Code.

(35) "Air contaminant source" has the same meaning as in section 3704.01 of the Revised Code.

(36) "Cogeneration technology" means technology that produces electricity and useful thermal output simultaneously.

(37)

(a) "Renewable energy resource" means any of the following:

(i) Solar photovoltaic or solar thermal energy;

(ii) Wind energy;

(iii) Power produced by a hydroelectric facility;

(iv) Power produced by a run-of-the-river hydroelectric facility placed in service on or after January 1, 1980, that is located within this state, relies upon the Ohio river, and operates, or is rated to operate, at an aggregate capacity of forty or more megawatts;

(v) Geothermal energy;

(vi) Fuel derived from solid wastes, as defined in section 3734.01 of the Revised Code, through fractionation, biological decomposition, or other process that does not principally involve combustion;

(vii) Biomass energy;

(viii) Energy produced by cogeneration technology that is placed into service on or before December 31, 2015, and for which more than ninety per cent of the total annual energy input is from combustion of a waste or byproduct gas from an air contaminant source in this state, which source has been in operation since on or before January 1, 1985, provided that the cogeneration technology is a part of a facility located in a county having a population of more than three hundred sixty-five thousand but less than three hundred seventy thousand according to the most recent federal decennial census;

(ix) Biologically derived methane gas;

(x) Heat captured from a generator of electricity, boiler, or heat exchanger fueled by biologically derived methane gas;

(xi) Energy derived from nontreated by-products of the pulping process or wood manufacturing process, including bark, wood chips, sawdust, and lignin in spent pulping liquors.

"Renewable energy resource" includes, but is not limited to, any fuel cell used in the generation of electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid oxide fuel cell; wind turbine located in the state's territorial waters of Lake Erie; methane gas emitted from an abandoned coal mine; waste energy recovery system placed into service or retrofitted on or after the effective date of the amendment of this section by S.B. 315 of the 129th general assembly, September 10, 2012, except that a waste energy recovery system described in division (A)(38)(b) of this section may be included only if it was placed into service between January 1, 2002, and December 31, 2004; storage facility that will promote the better utilization of a renewable energy resource; or distributed generation system used by a customer to generate electricity from any such energy.

"Renewable energy resource" does not include a waste energy recovery system that is, or was, on or after January 1, 2012, included in an energy efficiency program of an electric distribution utility pursuant to requirements under section 4928.66 of the Revised Code.

(b) As used in division (A)(37) of this section, "hydroelectric facility" means a hydroelectric generating facility that is located at a dam on a river, or on any water discharged to a river, that is within or bordering this state or within or bordering an adjoining state and meets all of the following standards:

(i) The facility provides for river flows that are not detrimental for fish, wildlife, and water quality, including seasonal flow fluctuations as defined by the applicable licensing agency for the facility.

(ii) The facility demonstrates that it complies with the water quality standards of this state, which compliance may consist of certification under Section 401 of the "Clean Water Act of 1977," 91 Stat. 1598, 1599, 33 U.S.C. 1341, and demonstrates that it has not contributed to a finding by this state that the river has impaired water quality under Section 303(d) of the "Clean Water Act of 1977," 114 Stat. 870, 33 U.S.C. 1313.

(iii) The facility complies with mandatory prescriptions regarding fish passage as required by the federal energy regulatory commission license issued for the project, regarding fish protection for riverine, anadromous, and catadromous fish.

(iv) The facility complies with the recommendations of the Ohio environmental protection agency and with the terms of its federal energy regulatory commission license regarding watershed protection, mitigation, or enhancement, to the extent of each agency's respective jurisdiction over the facility.

(v) The facility complies with provisions of the "Endangered Species Act of 1973," 87 Stat. 884, 16 U.S.C. 1531 to 1544, as amended.

(vi) The facility does not harm cultural resources of the area. This can be shown through compliance with the terms of its federal energy regulatory commission license or, if the facility is not regulated by that commission, through development of a plan approved by the Ohio historic preservation office, to the extent it has jurisdiction over the facility.

(vii) The facility complies with the terms of its federal energy regulatory commission license or exemption that are related to recreational access, accommodation, and facilities or, if the facility is not regulated by that commission, the facility complies with similar requirements as are recommended by resource agencies, to the extent they have jurisdiction over the facility; and the facility provides access to water to the public without fee or charge.

(viii) The facility is not recommended for removal by any federal agency or agency of any state, to the extent the particular agency has jurisdiction over the facility.

(38) "Waste energy recovery system" means either of the following:

(a) A facility that generates electricity through the conversion of energy from either of the following:

(i) Exhaust heat from engines or manufacturing, industrial, commercial, or institutional sites, except for exhaust heat from a facility whose primary purpose is the generation of electricity;

(ii) Reduction of pressure in gas pipelines before gas is distributed through the pipeline, provided that the conversion of energy to electricity is achieved without using additional fossil fuels.

(b) A facility at a state institution of higher education as defined in section 3345.011 of the Revised Code that recovers waste heat from electricity-producing engines or combustion turbines and that simultaneously uses the recovered heat to produce steam, provided that the facility was placed into service between January 1, 2002, and December 31, 2004.

(39) "Smart grid" means capital improvements to an electric distribution utility's distribution infrastructure that improve reliability, efficiency, resiliency, or reduce energy demand or use, including, but not limited to, advanced metering and automation of system functions.

(40) "Combined heat and power system" means the coproduction of electricity and useful thermal energy from the same fuel source designed to achieve thermal-efficiency levels of at least sixty per cent, with at least twenty per cent of the system's total useful energy in the form of thermal energy.

(B) For the purposes of this chapter, a retail electric service component shall be deemed a competitive retail electric service if the service component is competitive pursuant to a declaration by a provision of the Revised Code or pursuant to an order of the public utilities commission authorized under division (A) of section 4928.04 of the Revised Code. Otherwise, the service component shall be deemed a noncompetitive retail electric service.

Cite as R.C. § 4928.01

Amended by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

Amended by 129th General AssemblyFile No.125, SB 315, §101.01, eff. 9/10/2012.

Amended by 128th General AssemblyFile No.47, SB 181, §1, eff. 9/13/2010.

Amended by 128th General AssemblyFile No.48, SB 232, §1, eff. 6/17/2010.

Amended by 128th General AssemblyFile No.9, HB 1, §101.01, eff. 10/16/2009.

Effective Date: 10-05-1999; 01-04-2007; 2008 SB221 07-31-2008

4928.02 State policy.

It is the policy of this state to do the following throughout this state:

(A) Ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service;

(B) 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;

(C) 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;

(D) Encourage innovation and market access for cost-effective supply- and demand-side retail electric service including, but not limited to, demand-side management, time-differentiated pricing, waste energy recovery systems, smart grid programs, and implementation of advanced metering infrastructure;

(E) 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;

(F) 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;

(G) Recognize the continuing emergence of competitive electricity markets through the development and implementation of flexible regulatory treatment;

(H) 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 any generation-related costs through distribution or transmission rates;

(I) Ensure retail electric service consumers protection against unreasonable sales practices, market deficiencies, and market power;

(J) Provide coherent, transparent means of giving appropriate incentives to technologies that can adapt successfully to potential environmental mandates;

(K) Encourage implementation of distributed generation across customer classes through regular review and updating of administrative rules governing critical issues such as, but not limited to, interconnection standards, standby charges, and net metering;

(L) Protect at-risk populations, including, but not limited to, when considering the implementation of any new advanced energy or renewable energy resource;

(M) Encourage the education of small business owners in this state regarding the use of, and encourage the use of, energy efficiency programs and alternative energy resources in their businesses;

(N) Facilitate the state's effectiveness in the global economy.

In carrying out this policy, the commission shall consider rules as they apply to the costs of electric distribution infrastructure, including, but not limited to, line extensions, for the purpose of development in this state.

Cite as R.C. § 4928.02

Amended by 129th General AssemblyFile No.125, SB 315, §101.01, eff. 9/10/2012.

Effective Date: 10-05-1999; 2008 SB221 07-31-2008

4928.03 Identification of competitive services and noncompetitive services.

Beginning on the starting date of competitive retail electric service, retail electric generation, aggregation, power marketing, and power brokerage services supplied to consumers within the certified territory of an electric utility are competitive retail electric services that the consumers may obtain subject to this chapter from any supplier or suppliers. In accordance with a filing under division (F) of section 4933.81 of the

Revised Code, retail electric generation, aggregation, power marketing, or power brokerage services supplied to consumers within the certified territory of an electric cooperative that has made the filing are competitive retail electric services that the consumers may obtain subject to this chapter from any supplier or suppliers. Beginning on the starting date of competitive retail electric service and notwithstanding any other provision of law, each consumer in this state and the suppliers to a consumer shall have comparable and nondiscriminatory access to noncompetitive retail electric services of an electric utility in this state within its certified territory for the purpose of satisfying the consumer's electricity requirements in keeping with the policy specified in section 4928.02 of the Revised Code.

Cite as R.C. § 4928.03

Effective Date: 10-05-1999

4928.04 Additional competitive services.

(A) The public utilities commission by order may declare that retail ancillary, metering, or billing and collection service supplied to consumers within the certified territory of an electric utility on or after the starting date of competitive retail electric service is a competitive retail electric service that the consumers may obtain from any supplier or suppliers subject to this chapter. The commission may issue such order, after investigation and public hearing, only if it first determines either of the following:

(1) There will be effective competition with respect to the service.

(2) The customers of the service have reasonably available alternatives. The commission shall initiate a proceeding on or before March 31, 2003, on the question of the desirability, feasibility, and timing of any such competition.

(B) In carrying out division (A) of this section, the commission may prescribe different classifications, procedures, terms, or conditions for different electric utilities and for the retail electric services they provide that are declared competitive pursuant to that division, provided the classifications, procedures, terms, or conditions are reasonable and do not confer any undue economic, competitive, or market advantage or preference upon any electric utility.

Cite as R.C. § 4928.04

Effective Date: 10-05-1999

4928.05 Extent of exemptions.

(A)

(1) On and after the starting date of competitive retail electric service, a competitive retail electric service supplied by an electric utility or electric services company shall not be subject to supervision and regulation by a municipal corporation under Chapter 743. of the Revised Code or by the public utilities commission under Chapters 4901. to 4909., 4933., 4935., and 4963. of the Revised Code, except sections 4905.10 and 4905.31 , division (B) of section 4905.33 , and sections 4905.35 and 4933.81 to 4933.90 ; except sections 4905.06 , 4935.03 , 4963.40 , and 4963.41 of the Revised Code only to the extent related to service reliability and public safety; and except as otherwise provided in this chapter. The commission's authority to enforce those excepted provisions with respect to a competitive retail electric service shall be such authority as is provided for their enforcement under Chapters 4901. to 4909., 4933., 4935., and 4963. of the Revised Code and this chapter. Nothing in this division shall be construed to limit the commission's authority under sections 4928.141 to 4928.144 of the Revised Code. On and after the

starting date of competitive retail electric service, a competitive retail electric service supplied by an electric cooperative shall not be subject to supervision and regulation by the commission under Chapters 4901. to 4909., 4933., 4935., and 4963. of the Revised Code, except as otherwise expressly provided in sections 4928.01 to 4928.10 and 4928.16 of the Revised Code.

(2) On and after the starting date of competitive retail electric service, a noncompetitive retail electric service supplied by an electric utility shall be subject to supervision and regulation by the commission under Chapters 4901. to 4909., 4933., 4935., and 4963. of the Revised Code and this chapter, to the extent that authority is not preempted by federal law. The commission's authority to enforce those provisions with respect to a noncompetitive retail electric service shall be the authority provided under those chapters and this chapter, to the extent the authority is not preempted by federal law. Notwithstanding Chapters 4905. and 4909. of the Revised Code, commission authority under this chapter shall include the authority to provide for the recovery, through a reconcilable rider on an electric distribution utility's distribution rates, of all transmission and transmission-related costs, including ancillary and congestion costs, imposed on or charged to the utility by the federal energy regulatory commission or a regional transmission organization, independent transmission operator, or similar organization approved by the federal energy regulatory commission. The commission shall exercise its jurisdiction with respect to the delivery of electricity by an electric utility in this state on or after the starting date of competitive retail electric service so as to ensure that no aspect of the delivery of electricity by the utility to consumers in this state that consists of a noncompetitive retail electric service is unregulated. On and after that starting date, a noncompetitive retail electric service supplied by an electric cooperative shall not be subject to supervision and regulation by the commission under Chapters 4901. to 4909., 4933., 4935., and 4963. of the Revised Code, except sections 4933.81 to 4933.90 and 4935.03 of the Revised Code. The commission's authority to enforce those excepted sections with respect to a noncompetitive retail electric service of an electric cooperative shall be such authority as is provided for their enforcement under Chapters 4933. and 4935. of the Revised Code.

(B) Nothing in this chapter affects the authority of the commission under Title XLIX of the Revised Code to regulate an electric light company in this state or an electric service supplied in this state prior to the starting date of competitive retail electric service.

Cite as R.C. § 4928.05

Effective Date: 10-05-1999; 2008 SB221 07-31-2008

4928.06 Commission to ensure competitive retail electric service.

(A) Beginning on the starting date of competitive retail electric service, the public utilities commission shall ensure that the policy specified in section 4928.02 of the Revised Code is effectuated. To the extent necessary, the commission shall adopt rules to carry out this chapter. Initial rules necessary for the commencement of the competitive retail electric service under this chapter shall be adopted within one hundred eighty days after the effective date of this section. Except as otherwise provided in this chapter, the proceedings and orders of the commission under the chapter shall be subject to and governed by Chapter 4903. of the Revised Code.

(B) If the commission determines, on or after the starting date of competitive retail electric service, that there is a decline or loss of effective competition with respect to a competitive retail electric service of an electric utility, which service was declared competitive by commission order issued pursuant to division (A) of section 4928.04 of the Revised Code, the commission shall ensure that that service is provided at compensatory, fair, and nondiscriminatory prices and terms and conditions.

(C) In addition to its authority under section 4928.04 of the Revised Code and divisions (A) and (B) of this section, the commission, on an ongoing basis, shall monitor and evaluate the provision of retail electric service in this state for the purpose of discerning any noncompetitive retail electric service that should be available on a competitive basis on or after the starting date of competitive retail electric service pursuant to a declaration in the Revised Code, and for the purpose of discerning any competitive retail electric service that is no longer subject to effective competition on or after that date. Upon such evaluation, the commission periodically shall report its findings and any recommendations for legislation to the standing committees of both houses of the general assembly that have primary jurisdiction regarding public utility legislation. Until 2008, the commission and the consumer's counsel also shall provide biennial reports to those standing committees, regarding the effectiveness of competition in the supply of competitive retail electric services in this state. In addition, until the end of all market development periods as determined by the commission under section 4928.40 of the Revised Code, those standing committees shall meet at least biennially to consider the effect on this state of electric service restructuring and to receive reports from the commission, consumers' counsel, and director of development.

(D) In determining, for purposes of division (B) or (C) of this section, whether there is effective competition in the provision of a retail electric service or reasonably available alternatives for that service, the commission shall consider factors including, but not limited to, all of the following:

(1) The number and size of alternative providers of that 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;

(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. The burden of proof shall be on any entity requesting, under division (B) or (C) of this section, a determination by the commission of the existence of or a lack of effective competition or reasonably available alternatives.

(E)

(1) Beginning on the starting date of competitive retail electric service, the commission has authority under Chapters 4901. to 4909. of the Revised Code, and shall exercise that authority, to resolve abuses of market power by any electric utility that interfere with effective competition in the provision of retail electric service.

(2) In addition to the commission's authority under division (E)(1) of this section, the commission, beginning the first year after the market development period of a particular electric utility and after reasonable notice and opportunity for hearing, may take such measures within a transmission constrained area in the utility's certified territory as are necessary to ensure that retail electric generation service is provided at reasonable rates within that area. The commission may exercise this authority only upon findings that an electric utility is or has engaged in the abuse of market power and that that abuse is not adequately mitigated by rules and practices of any independent transmission entity controlling the transmission facilities. Any such measure shall be taken only to the extent necessary to protect customers in the area from the particular abuse of market power and to the extent the commission's authority is not preempted by federal law. The measure shall remain the commission, after reasonable notice and opportunity for hearing, determines that the particular abuse of market power has been mitigated.

(F) An electric utility, electric services company, electric cooperative, or governmental aggregator subject to certification under section 4928.08 of the Revised Code shall provide the commission with such information, regarding a competitive retail electric service for which it is subject to certification, as the commission considers necessary to carry out this chapter. An electric utility shall provide the commission with such information as the commission considers necessary to carry out divisions (B) to (E) of this section. The commission shall take such measures as it considers necessary to protect the confidentiality of any such information. The commission shall require each electric utility to file with the commission on and after the starting date of competitive retail electric service an annual report of its intrastate gross receipts and sales of kilowatt hours of electricity, and shall require each electric services company, electric cooperative, and governmental aggregator subject to certification to file an annual report on and after that starting date of such receipts and sales from the provision of those retail electric services for which it is subject to certification. For the purpose of the reports, sales of kilowatt hours of electricity are deemed to occur at the meter of the retail customer.

Cite as R.C. § 4928.06

Effective Date: 10-05-1999

4928.07 Separate pricing of services on bill.

To the maximum extent practicable on or after the starting date of competitive retail electric service, an electric utility, electric services company, electric cooperative, or governmental aggregator subject to certification under section 4928.08 of the Revised Code shall separately price competitive retail electric services, and the prices shall be itemized on the bill of a customer or otherwise disclosed to the customer. Although a competitive retail electric service shall be supplied to any consumer on such a basis, such an electric utility, electric services company, electric cooperative, or governmental aggregator may repackage the service on or after the starting date and offer it on a bundled basis with other retail electric services to meet consumer preferences. Such repackaging by an electric utility shall be subject to sections 4905.33 to 4905.35 of the Revised Code. Repackaging by such an electric services company, electric cooperative, or governmental aggregator shall be subject to the limitation that no such entity, as to a competitive retail electric service for which the company, cooperative, or aggregator is subject to certification, shall furnish free service or service for less than actual cost for the purpose of destroying competition.

Cite as R.C. § 4928.07

Effective Date: 10-05-1999

4928.08 Certification to provide retail electric competitive service.

(A) This section applies to an electric cooperative, or to a governmental aggregator that is a municipal electric utility, only to the extent of a competitive retail electric service it provides to a customer to whom it does not provide a noncompetitive retail electric service through transmission or distribution facilities it singly or jointly owns or operates.

(B) No electric utility, electric services company, electric cooperative, or governmental aggregator shall provide a competitive retail electric service to a consumer in this state on and after the starting date of competitive retail electric service without first being certified by the public utilities commission regarding its managerial, technical, and financial capability to provide that service and providing a financial guarantee sufficient to protect customers and electric distribution utilities from default. Certification shall be granted pursuant to procedures and standards the commission shall prescribe in accordance with division (C) of this section, except that certification or certification renewal shall be deemed approved thirty days after the filing of an application with the commission unless the commission suspends that approval for good cause shown. In the case of such a suspension, the commission shall act to approve or deny certification or certification renewal to the applicant not later than ninety days after the date of the suspension.

(C) Capability standards adopted in rules under division (B) of this section shall be sufficient to ensure compliance with the minimum service requirements established under section 4928.10 of the Revised Code and with section 4928.09 of the Revised Code. The standards shall allow flexibility for voluntary aggregation, to encourage market creativity in responding to consumer needs and demands, and shall allow flexibility for electric services companies that exclusively provide installation of small electric generation facilities, to provide ease of market access. The rules shall include procedures for biennially renewing certification.

(D) The commission may suspend, rescind, or conditionally rescind the certification of any electric utility, electric services company, electric cooperative, or governmental aggregator issued under this section if the commission determines, after reasonable notice and opportunity for hearing, that the utility, company, cooperative, or aggregator has failed to comply with any applicable certification standards or has engaged in anticompetitive or unfair, deceptive, or unconscionable acts or practices in this state.

(E) No electric distribution utility on and after the starting date of competitive retail electric service shall knowingly distribute electricity, to a retail consumer in this state, for any supplier of electricity that has not been certified by the commission pursuant to this section.

Cite as R.C. § 4928.08

Effective Date: 10-05-1999

4928.09 Consent to jurisdiction - appointment of statutory agent.

(A)

(1) No person shall operate in this state as an electric utility, an electric services company, a billing and collection agent, or a regional transmission organization approved by the federal energy regulatory commission and having the responsibility for maintaining reliability in all or part of this state on and after the starting date of competitive retail electric service unless that person first does both of the following:

(a) Consents irrevocably to the jurisdiction of the courts of this state and service of process in this state, including, without limitation, service of summonses and subpoenas, for any civil or criminal proceeding arising out of or relating to such operation, by providing that irrevocable consent in accordance with division (A)(4) of this section;

(b) Designates an agent authorized to receive that service of process in this state, by filing with the commission a document designating that agent.

(2) No person shall continue to operate as such an electric utility, electric services company, billing and collection agent, or regional transmission organization described in division (A)(1) of this section unless that person continues to consent to such jurisdiction and service of process in this state and continues to designate an agent as provided under this division, by refiling in accordance with division (A)(4) of this section the appropriate documents filed under division (A)(1) of this section or, as applicable, the appropriate amended documents filed under division (A)(3) of this section. Such refiling shall occur during the month of December of every fourth year after the initial filing of a document under division (A)(1) of this section.

(3) If the address of the person filing a document under division (A)(1) or (2) of this section changes, or if a person's agent or the address of the agent changes, from that listed on the most recently filed of such documents, the person shall file an amended document containing the new information.

(4) The consent and designation required by divisions (A)(1) to (3) of this section shall be in writing, on forms prescribed by the public utilities commission. The original of each such document or amended document shall be legible and shall be filed with the commission, with a copy filed with the office of the consumers' counsel and with the attorney general's office.

(B) A person who enters this state pursuant to a summons, subpoena, or other form of process authorized by this section is not subject to arrest or service of process, whether civil or criminal, in connection with other matters that arose before the person's entrance into this state pursuant to such summons, subpoena, or other form of process.

(C) Divisions (A) and (B) of this section do not apply to any of the following:

(1) A corporation incorporated under the laws of this state that has appointed a statutory agent pursuant to section 1701.07 or 1702.06 of the Revised Code;

(2) A foreign corporation licensed to transact business in this state that has appointed a designated agent pursuant to section 1703.041 of the Revised Code;

(3) Any other person that is a resident of this state or that files consent to service of process and designates a statutory agent pursuant to other laws of this state.

Cite as R.C. § 4928.09

Effective Date: 10-05-1999; 2008 SB221 07-31-2008

4928.10 Minimum service requirements for competitive services.

For the protection of consumers in this state, the public utilities commission shall adopt rules under division (A) of section 4928.06 of the Revised Code specifying the necessary minimum service requirements, on or after the starting date of competitive retail electric service, of an electric utility, electric services company, electric cooperative, or governmental aggregator subject to certification under section 4928.08 of the Revised Code regarding the provision directly or through its billing and collection agent of competitive retail electric services for which it is subject to certification. Rules adopted under this section shall include a prohibition against unfair, deceptive, and unconscionable acts and practices in the marketing, solicitation, and sale of such a competitive retail electric service and in the administration of any contract for service, and also shall include additional consumer protections concerning all of the following:

(A) Contract disclosure. The rules shall include requirements that an electric utility, electric services company, electric cooperative, or governmental aggregator subject to certification under section 4928.08 of the Revised Code do both of the following:

(1) Provide consumers with adequate, accurate, and understandable pricing and terms and conditions of service, including any switching fees, and with a document containing the terms and conditions of pricing and service before the consumer enters into the contract for service;

(2) Disclose the conditions under which a customer may rescind a contract without penalty.

(B) Service termination. The rules shall include disclosure of the terms identifying how customers may switch or terminate service, including any required notice and any penalties.

(C) Minimum content of customer bills. The rules shall include all of the following requirements, which shall be standardized:

(1) Price disclosure and disclosures of total billing units for the billing period and historical annual usage;

(2) To the maximum extent practicable, separate listing of each service component to enable a customer to recalculate its bill for accuracy;

(3) Identification of the supplier of each service;

(4) Statement of where and how payment may be made and provision of a toll-free or local customer assistance and complaint number for the electric utility, electric services company, electric cooperative, or governmental aggregator, as well as a consumer assistance telephone number or numbers for state agencies, such as the commission, the office of the consumers' counsel, and the attorney general's office, with the available hours noted;

(5) Other than for the first billing after the starting date of competitive retail electric service, highlighting and clear explanation on each customer bill, for two consecutive billing periods, of any changes in the rates, terms, and conditions of service.

(D) Disconnection and service termination, including requirements with respect to master-metered buildings. The rules shall include policies and procedures that are consistent with sections 4933.121 and 4933.122 of the Revised Code and the commission's rules adopted under those sections, and that provide for all of the following:

(1) Coordination between suppliers for the purpose of maintaining service;

(2) The allocation of partial payments between suppliers when service components are jointly billed;

(3) A prohibition against blocking, or authorizing the blocking of, customer access to a noncompetitive retail electric service when a customer is delinquent in payments to the electric utility or electric services company for a competitive retail electric service;

(4) A prohibition against switching, or authorizing the switching of, a customer's supplier of competitive retail electric service without the prior consent of the customer in accordance with appropriate confirmation practices, which may include independent, third-party verification procedures.

(5) A requirement of disclosure of the conditions under which a customer may rescind a decision to switch its supplier without penalty;

(6) Specification of any required notice and any penalty for early termination of contract.

(E) Minimum service quality, safety, and reliability. However, service quality, safety, and reliability requirements for electric generation service shall be determined primarily through market expectations and contractual relationships.

(F) Generation resource mix and environmental characteristics of power supplies. The rules shall include requirements for determination of the approximate generation resource mix and environmental characteristics of the power supplies and disclosure to the customer prior to the customer entering into a contract to purchase and four times per year under the contract. The rules also shall require that the electric utility, electric services company, electric cooperative, or governmental aggregator provide, or cause its billing and collection agent to provide, a customer with standardized information comparing the projected, with the actual and verifiable, resource mix and environmental characteristics. This disclosure shall occur not less than annually or not less than once during the contract period if the contract period is less than one year, and prior to any renewal of a contract.

(G) Customer information. The rules shall include requirements that the electric utility, electric services company, electric cooperative, or governmental aggregator make generic customer load pattern information available to other electric light companies on a comparable and nondiscriminatory basis, and make customer-specific information available to other electric light companies on a comparable and nondiscriminatory basis unless, as to customer-specific information, the customer objects. The rules shall ensure that each such utility, company, cooperative, or aggregator provide clear and frequent notice to its customers of the right to object and of applicable procedures. The rules shall establish the exact language that shall be used in all such notices.

Cite as R.C. § 4928.10

Effective Date: 10-05-1999

4928.11 Minimum service requirements for noncompetitive services.

(A) For the protection of consumers in this state, the public utilities commission shall adopt rules under division (A) of section 4928.06 of the Revised Code that specify minimum service quality, safety, and reliability requirements for noncompetitive retail electric services supplied by an electric utility in this state, to the extent such authority is not preempted by federal law. The rules shall include prescriptive standards for inspection, maintenance, repair, and replacement of the transmission and distribution systems of electric utilities; shall apply to each substantial type of transmission or distribution equipment or facility; shall establish uniform interconnection standards to ensure transmission and distribution system safety and reliability and shall otherwise provide for high quality, safe, and reliable electric service; shall include standards for operation, reliability, and safety during periods of emergency and disaster; and shall include voltage standards for efficient operation of single-phase motors. The rules regarding interconnection shall seek to prevent barriers to new technology and shall not make compliance unduly burdensome or expensive. When questions arise about specific equipment to meet interconnection standards, the commission shall initiate proceedings open to the public to solicit comments from all interested parties. Additionally, rules under this division shall include nondiscriminatory metering standards.

(B) The commission shall require each electric utility to report annually to the commission on and after the starting date of competitive retail electric service, regarding its compliance with the rules required under division (A) of this section. The commission shall make the filed reports available to the public. Periodically as determined by commission rule under division (A) of section 4928.06 of the Revised Code and in a proceeding initiated under division (B) of section 4928.16 of the Revised Code, the commission shall review a utility's report to determine the utility's compliance and may act pursuant to division (B) of section 4928.16 of the Revised Code to enforce compliance.

Cite as R.C. § 4928.11

Effective Date: 10-05-1999

4928.111 Review of distribution and transmission infrastructure.

The public utilities commission shall consult with electric distribution utilities to review the distribution infrastructure in this state and shall consult with regional transmission organizations and entities that own or control transmission facilities to review the transmission infrastructure in this state.

Cite as R.C. § 4928.111

Added by 129th General AssemblyFile No.125, SB 315, §101.01, eff. 9/10/2012.

4928.112 [Effective 9/12/2014] Priority to hospitals in case of outage.

(A) In the event of an interruption of electric service during a period of emergency or disaster, an electric distribution utility's service restoration plan shall give priority to hospitals that are customers of the electric distribution utility.

(B) If requested by a hospital that is its customer, an electric distribution utility shall confer at least biennially with that hospital regarding power quality issues and concerns related to the utility's facilities, including voltage sags, spikes, and harmonic disturbances, in an effort to minimize those events or their impact on the hospital.

(C) The public utilities commission shall adopt rules to carry out this section.

Added by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

4928.12 Qualifying transmission entities.

(A) Except as otherwise provided in sections 4928.31 to 4928.40 of the Revised Code, no entity shall own or control transmission facilities as defined under federal law and located in this state on or after the starting date of competitive retail electric service unless that entity is a member of, and transfers control of those facilities to, one or more qualifying transmission entities, as described in division (B) of this section, that are operational.

(B) An entity that owns or controls transmission facilities located in this state complies with division (A) of this section if each transmission entity of which it is a member meets all of the following specifications:

(1) The transmission entity is approved by the federal energy regulatory commission.

(2) The transmission entity effects separate control of transmission facilities from control of generation facilities.

(3) The transmission entity implements, to the extent reasonably possible, policies and procedures designed to minimize pancaked transmission rates within this state.

(4) The transmission entity improves service reliability within this state.

(5) The transmission entity achieves the objectives of an open and competitive electric generation marketplace, elimination of barriers to market entry, and preclusion of control of bottleneck electric transmission facilities in the provision of retail electric service.

(6) The transmission entity is of sufficient scope or otherwise operates to substantially increase economical supply options for consumers.

(7) The governance structure or control of the transmission entity is independent of the users of the transmission facilities, and no member of its board of directors has an affiliation, with such a user or with

an affiliate of a user during the member's tenure on the board, such as to unduly affect the transmission entity's performance. For the purpose of division (B)(7) of this section, a "user" is any entity or affiliate of that entity that buys or sells electric energy in the transmission entity's region or in a neighboring region.

(8) The transmission entity operates under policies that promote positive performance designed to satisfy the electricity requirements of customers.

(9) The transmission entity is capable of maintaining real-time reliability of the electric transmission system, ensuring comparable and nondiscriminatory transmission access and necessary services, minimizing system congestion, and further addressing real or potential transmission constraints.

(C) To the extent that a transmission entity under division (A) of this section is authorized to build transmission facilities, that transmission entity has the powers provided in and is subject to sections 1723.01 to 1723.08 of the Revised Code.

(D) For the purpose of forming or participating in a regional regulatory oversight body or mechanism developed for any transmission entity under division (A) of this section that is of regional scope and operates within this state:

(1) The commission shall make joint investigations, hold joint hearings, within or outside this state, and issue joint or concurrent orders in conjunction or concurrence with any official or agency of any state or of the United States, whether in the 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.

Cite as R.C. § 4928.12

Effective Date: 10-05-1999

4928.13 Nuclear generation facilities decommissioning.

Through a periodic filing with the public utilities commission in such form as the commission shall prescribe by rule under division (A) of section 4928.06 of the Revised Code, each electric utility that owns nuclear generation facilities located in this state shall demonstrate compliance with decommissioning requirements of the nuclear regulatory commission and public utilities commission and shall demonstrate adequate financing mechanisms to fund facility decommissioning.

Cite as R.C. § 4928.13

Effective Date: 10-05-1999

4928.14 Failure of supplier to provide service.

The failure of a supplier to provide retail electric generation service to customers within the certified territory of an electric distribution utility shall result in the supplier's customers, after reasonable notice, defaulting to the utility's standard service offer under sections 4928.141 , 4928.142 , and 4928.143 of the Revised Code until the customer chooses an alternative supplier. A supplier is deemed under this section 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:

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

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

(C) 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.

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

Cite as R.C. § 4928.14

Effective Date: 10-05-1999; 2008 SB221 07-31-2008

4928.141 Distribution utility to provide standard service offer.

(A) Beginning January 1, 2009, an electric distribution utility shall provide consumers, on a comparable and nondiscriminatory basis within its certified territory, a 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. To that end, the electric distribution utility shall apply to the public utilities commission to establish the standard service offer in accordance with section 4928.142 or 4928.143 of the Revised Code and, at its discretion, may apply simultaneously under both sections, except that the utility's first standard service offer application at minimum shall include a filing under section 4928.143 of the Revised Code. Only a standard service offer authorized in accordance with section 4928.142 or 4928.143 of the Revised Code, shall serve as the utility's standard service offer for the purpose of compliance with this section; and that standard service offer shall serve as the utility's default standard service offer for the purpose of section 4928.14 of the Revised Code. Notwithstanding the foregoing provision, the rate plan of an electric distribution utility shall continue for the purpose of the utility's compliance with this division until a standard service offer is first authorized under section 4928.142 or 4928.143 of the Revised Code, and, as applicable, pursuant to division (D) of section 4928.143 of the Revised Code, any rate plan that extends beyond December 31, 2008, shall continue to be in effect for the subject electric distribution utility for the duration of the plan's term. A standard service offer under section 4928.142 or 4928.143 of the Revised Code shall exclude any previously authorized allowances for transition costs, with such exclusion being effective on and after the date that the allowance is scheduled to end under the utility's rate plan.

(B) The commission shall set the time for hearing of a filing under section 4928.142 or 4928.143 of the Revised Code, send written notice of the hearing to the electric distribution utility, and publish notice in a newspaper of general circulation in each county in the utility's certified territory. The commission shall adopt rules regarding filings under those sections.

Cite as R.C. § 4928.141

Effective Date: 2008 SB221 07-31-2008

4928.142 Standard generation service offer price - competitive bidding.

(A) For the purpose of complying with section 4928.141 of the Revised Code and subject to division (D) of this section and, as applicable, subject to the rate plan requirement of division (A) of section 4928.141 of the Revised Code, an electric distribution utility may establish a standard service offer price for retail electric generation service that is delivered to the utility under a market-rate offer.

(1) The market-rate offer shall be determined through a competitive bidding process that provides for all of the following:

(a) Open, fair, and transparent competitive solicitation;

(b) Clear product definition;

(c) Standardized bid evaluation criteria;

(d) Oversight by an independent third party that shall design the solicitation, administer the bidding, and ensure that the criteria specified in division (A)(1)(a) to (c) of this section are met;

(e) Evaluation of the submitted bids prior to the selection of the least-cost bid winner or winners. No generation supplier shall be prohibited from participating in the bidding process.

(2) The public utilities commission shall modify rules, or adopt new rules as necessary, concerning the conduct of the competitive bidding process and the qualifications of bidders, which rules shall foster supplier participation in the bidding process and shall be consistent with the requirements of division (A)(1) of this section.

(B) Prior to initiating a competitive bidding process for a market-rate offer under division (A) of this section, the electric distribution utility shall file an application with the commission. An electric distribution utility may file its application with the commission prior to the effective date of the commission rules required under division (A)(2) of this section, and, as the commission determines necessary, the utility shall immediately conform its filing to the rules upon their taking effect. An application under this division shall detail the electric distribution utility's proposed compliance with the requirements of division (A)(1) of this section and with commission rules under division (A)(2) of this section and demonstrate that all of the following requirements are met:

(1) The electric distribution utility or its transmission service affiliate belongs to at least one regional transmission organization that has been approved by the federal energy regulatory commission; or there otherwise is comparable and nondiscriminatory access to the electric transmission grid.

(2) Any such regional transmission organization has a market-monitor function and the ability to take actions to identify and mitigate market power or the electric distribution utility's market conduct; or a similar market monitoring function exists with commensurate ability to identify and monitor market conditions and mitigate conduct associated with the exercise of market power.

(3) A published source of information is available publicly or through subscription that identifies pricing

information for traded electricity on- and off-peak energy products that are contracts for delivery beginning at least two years from the date of the publication and is updated on a regular basis. The commission shall initiate a proceeding and, within ninety days after the application's filing date, shall determine by order whether the electric distribution utility and its market-rate offer meet all of the foregoing requirements. If the finding is positive, the electric distribution utility may initiate its competitive bidding process. If the finding is negative as to one or more requirements, the commission in the order shall direct the electric distribution utility regarding how any deficiency may be remedied in a timely manner to the commission's satisfaction; otherwise, the electric distribution utility shall withdraw the application. However, if such remedy is made and the subsequent finding is positive and also if the electric distribution utility made a simultaneous filing under this section and section 4928.143 of the Revised Code, the utility shall not initiate its competitive bid until at least one hundred fifty days after the filing date of those applications.

(C) Upon the completion of the competitive bidding process authorized by divisions (A) and (B) of this section, including for the purpose of division (D) of this section, the commission shall select the least-cost bid winner or winners of that process, and such selected bid or bids, as prescribed as retail rates by the commission, shall be the electric distribution utility's standard service offer unless the commission, by order issued before the third calendar day following the conclusion of the competitive bidding process for the market rate offer, determines that one or more of the following criteria were not met:

(1) Each portion of the bidding process was oversubscribed, such that the amount of supply bid upon was greater than the amount of the load bid out.

(2) There were four or more bidders.

(3) At least twenty-five per cent of the load is bid upon by one or more persons other than the electric distribution utility. All costs incurred by the electric distribution utility as a result of or related to the competitive bidding process or to procuring generation service to provide the standard service offer, including the costs of energy and capacity and the costs of all other products and services procured as a result of the competitive bidding process, shall be timely recovered through the standard service offer price, and, for that purpose, the commission shall approve a reconciliation mechanism, other recovery mechanism, or a combination of such mechanisms for the utility.

(D) The first application filed under this section by an electric distribution utility that, as of July 31, 2008, directly owns, in whole or in part, operating electric generating facilities that had been used and useful in this state shall require that a portion of that utility's standard service offer load for the first five years of the market rate offer be competitively bid under division (A) of this section as follows: ten per cent of the load in year one, not more than twenty per cent in year two, thirty per cent in year three, forty per cent in year four, and fifty per cent in year five. Consistent with those percentages, the commission shall determine the actual percentages for each year of years one through five. The standard service offer price for retail electric generation service under this first application shall be a proportionate blend of the bid price and the generation service price for the remaining standard service offer load, which latter price shall be equal to the electric distribution utility's most recent standard service offer price, adjusted upward or downward as the commission determines reasonable, relative to the jurisdictional portion of any known and measurable changes from the level of any one or more of the following costs as reflected in that most recent standard service offer price:

(1) The electric distribution utility's prudently incurred cost of fuel used to produce electricity;

(2) Its prudently incurred purchased power costs;

(3) Its prudently incurred costs of satisfying the supply and demand portfolio requirements of this state, including, but not limited to, renewable energy resource and energy efficiency requirements;

(4) Its costs prudently incurred to comply with environmental laws and regulations, with consideration of the derating of any facility associated with those costs. In making any adjustment to the most recent standard service offer price on the basis of costs described in division (D) of this section, the commission shall include the benefits that may become available to the electric distribution utility as a result of or in connection with the costs included in the adjustment, including, but not limited to, the utility's receipt of emissions credits or its receipt of tax benefits or of other benefits, and, accordingly, the commission may impose such conditions on the adjustment to ensure that any such benefits are properly aligned with the associated cost responsibility. The commission shall also determine how such adjustments will affect the electric distribution utility's return on common equity that may be achieved by those adjustments. The commission shall not apply its consideration of the return on common equity to reduce any adjustments authorized under this division unless the adjustments will cause the electric distribution utility to earn a return on common equity that is significantly in excess of the return on common equity that is earned by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. The burden of proof for demonstrating that significantly excessive earnings will not occur shall be on the electric distribution utility. Additionally, the commission may adjust the electric distribution utility's most recent standard service offer price by such just and reasonable amount that the commission determines necessary to address any emergency that threatens the utility's financial integrity or to ensure that the resulting revenue available to the utility for providing the standard service offer is not so inadequate as to result, directly or indirectly, in a taking of property without compensation pursuant to Section 19 of Article I, Ohio Constitution. The electric distribution utility has the burden of demonstrating that any adjustment to its most recent standard service offer price is proper in accordance with this division.

(E) Beginning in the second year of a blended price under division (D) of this section and notwithstanding any other requirement of this section, the commission may alter prospectively the proportions specified in that division to mitigate any effect of an abrupt or significant change in the electric distribution utility's standard service offer price that would otherwise result in general or with respect to any rate group or rate schedule but for such alteration. Any such alteration shall be made not more often than annually, and the commission shall not, by altering those proportions and in any event, including because of the length of time, as authorized under division (C) of this section, taken to approve the market rate offer, cause the duration of the blending period to exceed ten years as counted from the effective date of the approved market rate offer. Additionally, any such alteration shall be limited to an alteration affecting the prospective proportions used during the blending period and shall not affect any blending proportion previously approved and applied by the commission under this division.

(F) An electric distribution utility that has received commission approval of its first application under division (C) of this section shall not, nor ever shall be authorized or required by the commission to, file an application under section 4928.143 of the Revised Code.

Cite as R.C. § 4928.142

Effective Date: 2008 SB221 07-31-2008; 2008 HB562 09-22-2008

4928.143 Application for approval of electric security plan - testing.

(A) For the purpose of complying with section 4928.141 of the Revised Code, an electric distribution utility may file an application for public utilities commission approval of an electric security plan as prescribed under division (B) of this section. The utility may file that application prior to the effective date of any rules the commission may adopt for the purpose of this section, and, as the commission determines necessary, the utility immediately shall conform its filing to those rules upon their taking effect.

(B) Notwithstanding any other provision of Title XLIX of the Revised Code to the contrary except division (D) of this section, divisions (I), (J), and (K) of section 4928.20 , division (E) of section 4928.64 , and section 4928.69 of the Revised Code:

(1) An electric security plan shall include provisions relating to the supply and pricing of electric generation service. In addition, if the proposed electric security plan has a term longer than three years, it may include provisions in the plan to permit the commission to test the plan pursuant to division (E) of this section and any transitional conditions that should be adopted by the commission if the commission terminates the plan as authorized under that division.

(2) The plan may provide for or include, without limitation, any of the following:

(a) Automatic recovery of any of the following costs of the electric distribution utility, provided the cost is prudently incurred: the cost of fuel used to generate the electricity supplied under the offer; the cost of purchased power supplied under the offer, including the cost of energy and capacity, and including purchased power acquired from an affiliate; the cost of emission allowances; and the cost of federally mandated carbon or energy taxes;

(b) A reasonable allowance for construction work in progress for any of the electric distribution utility's cost of constructing an electric generating facility or for an environmental expenditure for any electric generating facility of the electric distribution utility, provided the cost is incurred or the expenditure occurs on or after January 1, 2009. Any such allowance shall be subject to the construction work in progress allowance limitations of division (A) of section 4909.15 of the Revised Code, except that the commission may authorize such an allowance upon the incurrence of the cost or occurrence of the expenditure. No such allowance for generating facility construction shall be authorized, however, unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Further, no such allowance shall be authorized unless the facility's construction was sourced through a competitive bid process, regarding which process the commission may adopt rules. An allowance approved under division (B)(2)(b) of this section shall be established as a nonbypassable surcharge for the life of the facility.

(c) The establishment of a nonbypassable surcharge for the life of an electric generating facility that is owned or operated by the electric distribution utility, was sourced through a competitive bid process subject to any such rules as the commission adopts under division (B)(2)(b) of this section, and is newly used and useful on or after January 1, 2009, which surcharge shall cover all costs of the utility specified in the application, excluding costs recovered through a surcharge under division (B)(2)(b) of this section. However, no surcharge shall be authorized unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Additionally, if a surcharge is authorized for a facility pursuant to plan approval under division (C) of this section and as a condition of the continuation of the surcharge, the electric distribution utility shall dedicate to Ohio consumers the capacity and energy and the rate associated with the cost of that facility. Before the commission authorizes any surcharge pursuant to this division, it may consider, as applicable, the effects of any decommissioning, deratings, and retirements.

(d) 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 effect of stabilizing or providing certainty regarding retail electric service;

(e) Automatic increases or decreases in any component of the standard service offer price;

(f) Consistent with sections 4928.23 to 4928.2318 of the Revised Code, both of the following:

(i) Provisions for the electric distribution utility to securitize any phase-in, inclusive of carrying charges, of the utility's standard service offer price, which phase-in is authorized in accordance with section 4928.144 of the Revised Code;

(ii) Provisions for the recovery of the utility's cost of securitization.

(g) Provisions relating to transmission, ancillary, congestion, or any related service required for the standard service offer, including provisions for the recovery of any cost of such service that the electric distribution utility incurs on or after that date pursuant to the standard service offer;

(h) Provisions regarding the utility's distribution service, including, without limitation and notwithstanding any provision of Title XLIX of the Revised Code to the contrary, provisions regarding single issue ratemaking, a revenue decoupling mechanism or any other incentive ratemaking, and provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. The latter may include a long-term energy delivery infrastructure modernization plan for that utility or any plan providing for the utility's recovery of costs, including lost revenue, shared savings, and avoided costs, and a just and reasonable rate of return on such infrastructure modernization. As part of its determination as to whether to allow in an electric distribution utility's electric security plan inclusion of any provision described in division (B)(2)(h) of this section, the commission shall examine the reliability of the electric distribution utility's distribution system and ensure that customers' and the electric distribution utility's expectations are aligned and that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

(i) Provisions under which the electric distribution utility may implement economic development, job retention, and energy efficiency programs, which provisions may allocate program costs across all classes of customers of the utility and those of electric distribution utilities in the same holding company system.

(C)

(1) The burden of proof in the proceeding shall be on the electric distribution utility. The commission shall issue an order under this division for an initial application under this section not later than one hundred fifty days after the application's filing date and, for any subsequent application by the utility under this section, not later than two hundred seventy-five days after the application's filing date. Subject to division (D) of this section, 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 section 4928.142 of the Revised Code. Additionally, if the commission so approves an application that contains a surcharge under division (B)(2)(b) or (c) of this section, the commission shall ensure that the benefits derived for any purpose for which the surcharge is established are reserved and made available to those that bear the surcharge. Otherwise, the commission by order shall disapprove the application.

(2)

(a) If the commission modifies and approves an application under division (C)(1) of this section, the electric distribution utility may withdraw the application, thereby terminating it, and may file a new standard service offer under this section or a standard service offer under section 4928.142 of the Revised Code.

(b) If the utility terminates an application pursuant to division (C)(2)(a) of this section or if the commission disapproves an application under division (C)(1) of this section, the commission shall issue such order as is necessary to continue the provisions, terms, and conditions of the utility's most recent standard service offer, along with any expected increases or decreases in fuel costs from those contained in that offer, until a subsequent offer is authorized pursuant to this section or section 4928.142 of the Revised Code, respectively.

(D) Regarding the rate plan requirement of division (A) of section 4928.141 of the Revised Code, if an electric distribution utility that has a rate plan that extends beyond December 31, 2008, files an application under this section for the purpose of its compliance with division (A) of section 4928.141 of the Revised Code, that rate plan and its terms and conditions are hereby incorporated into its proposed electric security plan and shall continue in effect until the date scheduled under the rate plan for its expiration, and that portion of the electric security plan shall not be subject to commission approval or disapproval under division (C) of this section, and the earnings test provided for in division (F) of this section shall not apply until after the expiration of the rate plan. However, that utility may include in its electric security plan under this section, and the commission may approve, modify and approve, or disapprove subject to division (C) of this section, provisions for the incremental recovery or the deferral of any costs that are not being recovered under the rate plan and that the utility incurs during that continuation period to comply with section 4928.141 , division (B) of section 4928.64 , or division (A) of section 4928.66 of the Revised Code.

(E) If an electric security plan approved under division (C) of this section, except one withdrawn by the utility as authorized under that division, has a term, exclusive of phase-ins or deferrals, that exceeds three years from the effective date of the plan, the commission shall test the plan in the fourth year, and if applicable, every fourth year thereafter, to determine whether the plan, including its then-existing pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, continues to be more favorable in the aggregate and during the remaining term of the plan as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. The commission shall also determine the prospective effect of the electric security plan to determine if that effect is substantially likely to provide the electric distribution utility with a return on common equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. The burden of proof for demonstrating that significantly excessive earnings will not occur shall be on the electric distribution utility. If the test results are in the negative or the commission finds that continuation of the electric security plan will result in a return on equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that will face comparable business and financial risk, with such adjustments for capital structure as may be appropriate, during the balance of the plan, the commission may terminate the electric security plan, but not until it shall have provided interested parties with notice and an opportunity to be heard. The commission may impose such conditions on the plan's termination as it considers reasonable and necessary to accommodate the transition from an approved plan to the more advantageous alternative. In the event of an electric security plan's termination pursuant to this division, the commission shall permit the continued deferral and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan.

(F) With regard to the provisions that are included in an electric security plan under this section, the commission shall consider, following the end of each annual period of the plan, if any such adjustments resulted in excessive earnings as measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. Consideration also shall be given to the capital requirements of future committed investments in this state. The burden of proof for demonstrating that significantly excessive earnings did not occur shall be on the electric distribution utility. If the commission finds that such adjustments, in the aggregate, did result in significantly excessive earnings, it shall require the electric distribution utility to return to consumers the amount of the excess by prospective adjustments; provided that, upon making such prospective adjustments, the electric distribution utility shall have the right to terminate the plan and immediately file an application pursuant to section 4928.142 of the Revised Code. Upon termination of a plan under this division, rates shall be set on the same basis as specified in division (C)(2)(b) of this section, and the commission shall permit the continued deferral and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan. In making its determination of significantly excessive earnings under this division, the commission shall not consider, directly or indirectly, the revenue, expenses, or earnings of any affiliate or parent company.

Cite as R.C. § 4928.143

Amended by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

Effective Date: 2008 SB221 07-31-2008

4928.144 Phase-in of electric distribution utility rate or price.

The public utilities commission by order may authorize any just and reasonable phase-in of any electric distribution utility rate or price established under sections 4928.141 to 4928.143 of the Revised Code, and inclusive of carrying charges, as the commission considers necessary to ensure rate or price stability for consumers. If the commission's order includes such a phase-in, the order also shall provide for the creation of regulatory assets pursuant to generally accepted accounting principles, by authorizing the deferral of incurred costs equal to the amount not collected, plus carrying charges on that amount. Further, the order shall authorize the collection of those deferrals through a nonbypassable surcharge on any such rate or price so established for the electric distribution utility by the commission.

Cite as R.C. § 4928.144

Effective Date: 2008 SB221 07-31-2008

4928.145 Availability of contract or agreement relevant to proceeding.

During a proceeding under sections 4928.141 to 4928.144 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.

Cite as R.C. § 4928.145

Effective Date: 2008 SB221 07-31-2008

4928.146 Electric service within territory of another utility.

Nothing in sections 4928.141 to 4928.145 of the Revised Code precludes or prohibits an electric distribution utility providing competitive retail electric service to electric load centers within the certified territory of another such utility.

Cite as R.C. § 4928.146

Effective Date: 2008 SB221 07-31-2008

4928.15 Schedules for provision of noncompetitive service.

(A) Except as otherwise provided in sections 4928.31 to 4928.40 of the Revised Code, no electric utility shall supply noncompetitive retail electric distribution service in this state on or after the starting date of competitive retail electric service except pursuant to a schedule for that service that is consistent with the state policy specified in section 4928.02 of the Revised Code and filed with the public utilities commission under section 4909.18 of the Revised Code. The schedule shall provide that electric distribution service under the schedule is available to all consumers within the utility's certified territory and to any supplier to those consumers on a nondiscriminatory and comparable basis. Distribution service rates and charges under the schedule shall be established in accordance with Chapters 4905. and 4909. of the Revised Code. The schedule shall 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 commission.

(B) Except as otherwise provided in sections 4928.31 to 4928.40 of the Revised Code and except as preempted by federal law, no electric utility shall supply the transmission service or ancillary service component of noncompetitive retail electric service in this state on or after the starting date of competitive retail electric service except pursuant to a schedule for that service component that is consistent with the state policy specified in section 4928.02 of the Revised Code and filed with the commission under section 4909.18 of the Revised Code. The schedule shall provide that transmission or ancillary service under the schedule is available to all consumers and to any supplier to those consumers on a nondiscriminatory and comparable basis. Service rates and charges under the schedule shall be established in accordance with Chapters 4905. and 4909. of the Revised Code.

(C) A self-generator shall have access to backup electricity supply from its competitive electric generation service provider at a rate to be determined by contract.

Cite as R.C. § 4928.15

Effective Date: 10-05-1999

4928.151 Uniform policy regarding electric transmission facilities.

The public utilities commission shall adopt and enforce rules prescribing a uniform, statewide policy regarding electric transmission and distribution line extensions and requisite substations and related facilities that are requested by nonresidential customers of electric utilities, so that, on and after the effective date of the initial rules so adopted, all such utilities apply the same policies and charges to those customers. Initial rules shall be adopted not later than six months after the effective date of this section.

The rules shall address the just and reasonable allocation to and utility recovery from the requesting customer or other customers of the utility of all costs of any such line extension and any requisite substation or related facility, including, but not limited to, the costs of necessary technical studies, operations and maintenance costs, and capital costs, including a return on capital costs.

Cite as R.C. § 4928.151

Effective Date: 2008 SB221 07-31-2008

4928.16 Commission juruisdiction.

(A)

(1) The public utilities commission has jurisdiction under section 4905.26 of the Revised Code, upon complaint of any person or upon complaint or initiative of the commission on or after the starting date of competitive retail electric service, regarding the provision by an electric utility, electric services company, electric cooperative, or governmental aggregator subject to certification under section 4928.08 of the Revised Code of any service for which it is subject to certification.

(2) The commission also has jurisdiction under section 4905.26 of the Revised Code, upon complaint of any person or upon complaint or initiative of the commission on or after the starting date of competitive retail electric service, to determine whether an electric utility has violated or failed to comply with any provision of sections 4928.01 to 4928.15 , any provision of divisions (A) to (D) of section 4928.35 of the Revised Code, or any rule or order adopted or issued under those sections; or whether an electric services company, electric cooperative, or governmental aggregator subject to certification under section 4928.08 of the Revised Code has violated or failed to comply with any provision of sections 4928.01 to 4928.10 of the Revised Code regarding a competitive retail electric service for which it is subject to certification or any rule or order adopted or issued under those sections.

(3) If a contract between a mercantile commercial customer and an electric services company states that the forum for a commercial dispute involving that company is through a certified commercial arbitration process, that process set forth in the contract and agreed to by the signatories shall be the exclusive forum unless all parties to the contract agree in writing to an amended process. The company shall notify the commission for informational purposes of all matters for which a contract remedy is invoked to resolve a dispute.

(4) The commission, by rule adopted pursuant to division (A) of section 4928.06 of the Revised Code, shall adopt alternative dispute resolution procedures for complaints by nonmercantile, nonresidential customers, including arbitration through a certified commercial arbitration process and at the commission. The commission also by such rule may adopt alternative dispute resolution procedures for complaints by residential customers.

(B) In addition to its authority under division (C) of section 4928.08 of the Revised Code and to any other remedies provided by law, the commission, after reasonable notice and opportunity for hearing in accordance with section 4905.26 of the Revised Code, may do any of the following:

(1) Order rescission of a contract, or restitution to customers including damages due to electric power fluctuations, in any complaint brought pursuant to division (A)(1) or (2) of this section;

(2) Order any remedy or forfeiture provided under sections 4905.54 to 4905.60 and 4905.64 of the Revised Code upon a finding under division (A)(2) of this section that the electric utility has violated or

failed to comply with any provision of sections 4928.01 to 4928.15 , any provision of divisions (A) to (D) of section 4928.35 of the Revised Code, or any rule or order adopted or issued under those sections. In addition, the commission may order any remedy provided under section 4905.22 , 4905.37 , or 4905.38 of the Revised Code if the violation or failure to comply by an electric utility related to the provision of a noncompetitive retail electric service.

(3) Order any remedy or forfeiture provided under sections 4905.54 to 4905.60 and 4905.64 of the Revised Code upon a finding under division (A)(2) of this section that the electric services company, electric cooperative, or governmental aggregator subject to certification under section 4928.08 of the Revised Code has violated or failed to comply, regarding a competitive retail electric service for which it is subject to certification, with any provision of sections 4928.01 to 4928.10 of the Revised Code or any rule or order adopted or issued under those sections.

(C)

(1) In addition to the authority conferred under section 4911.15 of the Revised Code, the consumers' counsel may file a complaint under division (A)(1) or (2) of this section on behalf of residential consumers in this state or appear before the commission as a representative of those consumers pursuant to any complaint filed under division (A)(1) or (2) of this section.

(2) In addition to the authority conferred under section 4911.19 of the Revised Code, the consumers' counsel, upon reasonable grounds on and after the starting date of competitive retail electric service, may file with the commission under section 4905.26 of the Revised Code a complaint for discovery if the recipient of an inquiry under section 4911.19 of the Revised Code fails to provide a response within the time specified in that section.

(D) Section 4905.61 of the Revised Code applies to a violation by an electric utility of, or to a failure of an electric utility to comply with, any provision of sections 4928.01 to 4928.15 , any provision of divisions (A) to (D) of section 4928.35 of the Revised Code, or any rule or order adopted or issued under those sections.

Cite as R.C. § 4928.16

Effective Date: 10-05-1999

4928.17 Corporate separation plans.

(A) Except as otherwise provided in sections 4928.142 or 4928.143 or 4928.31 to 4928.40 of the Revised Code and beginning on the starting date of competitive retail electric service, no electric utility shall engage in this state, either directly or through an affiliate, in the businesses of supplying a noncompetitive retail electric service and supplying a competitive retail electric service, or in the businesses of supplying a noncompetitive retail electric service and supplying a product or service other than retail electric service, unless the utility implements and operates under a corporate separation plan that is approved by the public utilities commission under this section, is consistent with the policy specified in section 4928.02 of the Revised Code, and achieves all of the following:

(1) The plan provides, at minimum, for the provision of the competitive retail electric service or the nonelectric product or service through a fully separated affiliate of the utility, and the plan includes separate accounting requirements, the code of conduct as ordered by the commission pursuant to a rule it shall adopt under division (A) of section 4928.06 of the Revised Code, and such other measures as are necessary to effectuate the policy specified in section 4928.02 of the Revised Code.

(2) The plan satisfies the public interest in preventing unfair competitive advantage and preventing the abuse of market power.

(3) The plan is sufficient to ensure that the utility will not extend any undue preference or advantage to any affiliate, division, or part of its own business engaged in the business of supplying the competitive retail electric service or nonelectric product or service, including, but not limited to, utility resources such as trucks, tools, office equipment, office space, supplies, customer and marketing information, advertising, billing and mailing systems, personnel, and training, without compensation based upon fully loaded embedded costs charged to the affiliate; and to ensure that any such affiliate, division, or part will not receive undue preference or advantage from any affiliate, division, or part of the business engaged in business of supplying the noncompetitive retail electric service. No such utility, affiliate, division, or part shall extend such undue preference. Notwithstanding any other division of this section, a utility's obligation under division (A)(3) of this section shall be effective January 1, 2000.

(B) The commission may approve, modify and approve, or disapprove a corporate separation plan filed with the commission under division (A) of this section. As part of the code of conduct required under division (A)(1) of this section, the commission shall adopt rules pursuant to division (A) of section 4928.06 of the Revised Code regarding corporate separation and procedures for plan filing and approval. The rules shall include limitations on affiliate practices solely for the purpose of maintaining a separation of the affiliate's business from the business of the utility to prevent unfair competitive advantage by virtue of that relationship. The rules also shall include an opportunity for any person having a real and substantial interest in the corporate separation plan to file specific objections to the plan and propose specific responses to issues raised in the objections, which objections and responses the commission shall address in its final order. Prior to commission approval of the plan, the commission shall afford a hearing upon those aspects of the plan that the commission determines reasonably require a hearing. The commission may reject and require refiling of a substantially inadequate plan under this section.

(C) The commission shall issue an order approving or modifying and approving a corporate separation plan under this section, to be effective on the date specified in the order, only upon findings that the plan reasonably complies with the requirements of division (A) of this section and will provide for ongoing compliance with the policy specified in section 4928.02 of the Revised Code. However, for good cause shown, the commission may issue an order approving or modifying and approving a corporate separation plan under this section that does not comply with division (A)(1) of this section but complies with such functional separation requirements as the commission authorizes to apply for an interim period prescribed in the order, upon a finding that such alternative plan will provide for ongoing compliance with the policy specified in section 4928.02 of the Revised Code.

(D) Any party may seek an amendment to a corporate separation plan approved under this section, and the commission, pursuant to a request from any party or on its own initiative, may order as it considers necessary the filing of an amended corporate separation plan to reflect changed circumstances.

(E) No electric distribution utility shall sell or transfer any generating asset it wholly or partly owns at any time without obtaining prior commission approval.

Cite as R.C. § 4928.17

Effective Date: 10-05-1999; 2008 SB221 07-31-2008

4928.18 Jurisdiction and powers of commission concerning utility or affiliate.

(A) Notwithstanding division (E)(2)(a) of section 4909.15 of the Revised Code, nothing in this chapter prevents the public utilities commission from exercising its authority under Title XLIX of the Revised Code to protect customers of retail electric service supplied by an electric utility from any adverse effect of the utility's provision of a product or service other than retail electric service.

(B) The commission has jurisdiction under section 4905.26 of the Revised Code, upon complaint of any person or upon complaint or initiative of the commission on or after the starting date of competitive retail electric service, to determine whether an electric utility or its affiliate has violated any provision of section 4928.17 of the Revised Code or an order issued or rule adopted under that section. For this purpose, the commission may examine such books, accounts, or other records kept by an electric utility or its affiliate as may relate to the businesses for which corporate separation is required under section 4928.17 of the Revised Code, and may investigate such utility or affiliate operations as may relate to those businesses and investigate the interrelationship of those operations. Any such examination or investigation by the commission shall be governed by Chapter 4903. of the Revised Code.

(C) In addition to any remedies otherwise provided by law, the commission, regarding a determination of a violation pursuant to division (B) of this section, may do any of the following:

(1) Issue an order directing the utility or affiliate to comply;

(2) Modify an order as the commission finds reasonable and appropriate and order the utility or affiliate to comply with the modified order;

(3) Suspend or abrogate an order, in whole or in part;

(4) Issue an order that the utility or affiliate pay restitution to any person injured by the violation or failure to comply;

(D) In addition to any remedies otherwise provided by law, the commission, regarding a determination of a violation pursuant to division (B) of this section and commensurate with the severity of the violation, the source of the violation, any pattern of violations, or any monetary damages caused by the violation, may do either of the following:

(1) Impose a forfeiture on the utility or affiliate of up to twenty-five thousand dollars per day per violation. The recovery and deposit of any such forfeiture shall be subject to sections 4905.57 and 4905.59 of the Revised Code.

(2) Regarding a violation by an electric utility relating to a corporate separation plan involving competitive retail electric service, suspend or abrogate all or part of an order, to the extent it is in effect, authorizing an opportunity for the utility to receive transition revenues under a transition plan approved by the commission under section 4928.33 of the Revised Code.

Corporate separation under this section does not prohibit the common use of employee benefit plans, facilities, equipment, or employees, subject to proper accounting and the code of conduct ordered by the commission as provided in division (A)(1) of this section.

(E) Section 4905.61 of the Revised Code applies in the case of any violation of section 4928.17 of the Revised Code or of any rule adopted or order issued under that section.

Cite as R.C. § 4928.18

Amended by 129th General AssemblyFile No.20, HB 95, §1, eff. 9/9/2011.

Effective Date: 10-05-1999

4928.19 Consumer education.

As part of their ongoing consumer education efforts, the public utilities commission and the office of the consumers' counsel shall engage in cooperative agency efforts to educate consumers in this state regarding electric industry restructuring under this chapter.

Cite as R.C. § 4928.19

Effective Date: 10-05-1999

4928.20 [Effective Until 9/12/2014] Local aggregation of retail electric loads - limitations.

(A) The legislative authority of a municipal corporation may adopt an ordinance, or the board of township trustees of a township or the board of county commissioners of a county may adopt a resolution, under which, on or after the starting date of competitive retail electric service, it may aggregate in accordance with this section the retail electrical loads located, respectively, within the municipal corporation, township, or unincorporated area of the county and, for that purpose, may enter into service agreements to facilitate for those loads the sale and purchase of electricity. The legislative authority or board also may exercise such authority jointly with any other such legislative authority or board. For customers that are not mercantile customers, an ordinance or resolution under this division shall specify whether the aggregation will occur only with the prior, affirmative consent of each person owning, occupying, controlling, or using an electric load center proposed to be aggregated or will occur automatically for all such persons pursuant to the opt-out requirements of division (D) of this section. The aggregation of mercantile customers shall occur only with the prior, affirmative consent of each such person owning, occupying, controlling, or using an electric load center proposed to be aggregated. Nothing in this division, however, authorizes the aggregation of the retail electric loads of an electric load center, as defined in section 4933.81 of the Revised Code, that is located in the certified territory of a nonprofit electric supplier under sections 4933.81 to 4933.90 of the Revised Code or an electric load center served by transmission or distribution facilities of a municipal electric utility.

(B) If an ordinance or resolution adopted under division (A) of this section specifies that aggregation of customers that are not mercantile customers will occur automatically as described in that division, the ordinance or resolution shall direct the board of elections to submit the question of the authority to aggregate to the electors of the respective municipal corporation, township, or unincorporated area of a county at a special election on the day of the next primary or general election in the municipal corporation, township, or county. The legislative authority or board shall certify a copy of the ordinance or resolution to the board of elections not less than ninety days before the day of the special election. No ordinance or resolution adopted under division (A) of this section that provides for an election under this division shall take effect unless approved by a majority of the electors voting upon the ordinance or resolution at the election held pursuant to this division.

(C) Upon the applicable requisite authority under divisions (A) and (B) of this section, the legislative authority or board shall develop a plan of operation and governance for the aggregation program so authorized. Before adopting a plan under this division, the legislative authority or board shall hold at least two public hearings on the plan. Before the first hearing, the legislative authority or board shall publish notice of the hearings once a week for two consecutive weeks in a newspaper of general circulation in the jurisdiction or as provided in section 7.16 of the Revised Code. The notice shall summarize the plan and state the date, time, and location of each hearing.

(D) No legislative authority or board, pursuant to an ordinance or resolution under divisions (A) and (B) of this section that provides for automatic aggregation of customers that are not mercantile customers as described in division (A) of this section, shall aggregate the electrical load of any electric load center located within its jurisdiction unless it in advance clearly discloses to the person owning, occupying, controlling, or using the load center that the person will be enrolled automatically in the aggregation program and will remain so enrolled unless the person affirmatively elects by a stated procedure not to be so enrolled. The disclosure shall state prominently the rates, charges, and other terms and conditions of enrollment. The stated procedure shall allow any person enrolled in the aggregation program the opportunity to opt out of the program every three years, without paying a switching fee. Any such person that opts out before the commencement of the aggregation program pursuant to the stated procedure shall default to the standard service offer provided under section 4928.14 or division (D) of section 4928.35 of the Revised Code until the person chooses an alternative supplier.

(E)

(1) With respect to a governmental aggregation for a municipal corporation that is authorized pursuant to divisions (A) to (D) of this section, resolutions may be proposed by initiative or referendum petitions in accordance with sections 731.28 to 731.41 of the Revised Code.

(2) With respect to a governmental aggregation for a township or the unincorporated area of a county, which aggregation is authorized pursuant to divisions (A) to (D) of this section, resolutions may be proposed by initiative or referendum petitions in accordance with sections 731.28 to 731.40 of the Revised Code, except that:

(a) The petitions shall be filed, respectively, with the township fiscal officer or the board of county commissioners, who shall perform those duties imposed under those sections upon the city auditor or village clerk.

(b) The petitions shall contain the signatures of not less than ten per cent of the total number of electors in, respectively, the township or the unincorporated area of the county who voted for the office of governor at the preceding general election for that office in that area.

(F) A governmental aggregator under division (A) of this section is not a public utility engaging in the wholesale purchase and resale of electricity, and provision of the aggregated service is not a wholesale utility transaction. A governmental aggregator shall be subject to supervision and regulation by the public utilities commission only to the extent of any competitive retail electric service it provides and commission authority under this chapter.

(G) This section does not apply in the case of a municipal corporation that supplies such aggregated service to electric load centers to which its municipal electric utility also supplies a noncompetitive retail electric service through transmission or distribution facilities the utility singly or jointly owns or operates.

(H) A governmental aggregator shall not include in its aggregation the accounts of any of the following:

(1) A customer that has opted out of the aggregation;

(2) A customer in contract with a certified electric services company;

(3) A customer that has a special contract with an electric distribution utility;

(4) A customer that is not located within the governmental aggregator's governmental boundaries;

(5) Subject to division (C) of section 4928.21 of the Revised Code, a customer who appears on the "do not aggregate" list maintained under that section.

(I) Customers that are part of a governmental aggregation under this section shall be responsible only for such portion of a surcharge under section 4928.144 of the Revised Code that is proportionate to the benefits, as determined by the commission, that electric load centers within the jurisdiction of the governmental aggregation as a group receive. The proportionate surcharge so established shall apply to each customer of the governmental aggregation while the customer is part of that aggregation. If a customer ceases being such a customer, the otherwise applicable surcharge shall apply. Nothing in this section shall result in less than full recovery by an electric distribution utility of any surcharge authorized under section 4928.144 of the Revised Code. Nothing in this section shall result in less than the full and timely imposition, charging, collection, and adjustment by an electric distribution utility, its assignee, or any collection agent, of the phase-in-recovery charges authorized pursuant to a final financing order issued pursuant to sections 4928.23 to 4928.2318 of the Revised Code.

(J) On behalf of the customers that are part of a governmental aggregation under this section and by filing written notice with the public utilities commission, the legislative authority that formed or is forming that governmental aggregation may elect not to receive standby service within the meaning of division (B)(2)(d) of section 4928.143 of the Revised Code from an electric distribution utility in whose certified territory the governmental aggregation is located and that operates under an approved electric security plan under that section. Upon the filing of that notice, the electric distribution utility shall not charge any such customer to whom competitive retail electric generation service is provided by another supplier under the governmental aggregation for the standby service. Any such consumer that returns to the utility for competitive retail electric service shall pay the market price of power incurred by the utility to serve that consumer plus any amount attributable to the utility's cost of compliance with the alternative energy resource provisions of section 4928.64 of the Revised Code to serve the consumer. Such market price shall include, but not be limited to, capacity and energy charges; all charges associated with the provision of that power supply through the regional transmission organization, including, but not limited to, transmission, ancillary services, congestion, and settlement and administrative charges; and all other costs incurred by the utility that are associated with the procurement, provision, and administration of that power supply, as such costs may be approved by the commission. The period of time during which the market price and alternative energy resource amount shall be so assessed on the consumer shall be from the time the consumer so returns to the electric distribution utility until the expiration of the electric security plan. However, if that period of time is expected to be more than two years, the commission may reduce the time period to a period of not less than two years.

(K) 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.

Cite as R.C. § 4928.20

Amended by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

Amended by 129th General AssemblyFile No.28, HB 153, §101.01, eff. 9/29/2011.

Amended by 128th General AssemblyFile No.29, HB 48, §1, eff. 7/2/2010.

Effective Date: 06-15-2000; 12-20-2005; 07-04-2006; 2008 SB221 07-31-2008; 2008 HB562 09-22-2008

4928.20 [Effective 9/12/2014] Local aggregation of retail electric loads - limitations.

(A) The legislative authority of a municipal corporation may adopt an ordinance, or the board of township trustees of a township or the board of county commissioners of a county may adopt a resolution, under which, on or after the starting date of competitive retail electric service, it may aggregate in accordance with this section the retail electrical loads located, respectively, within the municipal corporation, township, or unincorporated area of the county and, for that purpose, may enter into service agreements to facilitate for those loads the sale and purchase of electricity. The legislative authority or board also may exercise such authority jointly with any other such legislative authority or board. For customers that are not mercantile customers, an ordinance or resolution under this division shall specify whether the aggregation will occur only with the prior, affirmative consent of each person owning, occupying, controlling, or using an electric load center proposed to be aggregated or will occur automatically for all such persons pursuant to the opt-out requirements of division (D) of this section. The aggregation of mercantile customers shall occur only with the prior, affirmative consent of each such person owning, occupying, controlling, or using an electric load center proposed to be aggregated. Nothing in this division, however, authorizes the aggregation of the retail electric loads of an electric load center, as defined in section 4933.81 of the Revised Code, that is located in the certified territory of a nonprofit electric supplier under sections 4933.81 to 4933.90 of the Revised Code or an electric load center served by transmission or distribution facilities of a municipal electric utility.

(B) If an ordinance or resolution adopted under division (A) of this section specifies that aggregation of customers that are not mercantile customers will occur automatically as described in that division, the ordinance or resolution shall direct the board of elections to submit the question of the authority to aggregate to the electors of the respective municipal corporation, township, or unincorporated area of a county at a special election on the day of the next primary or general election in the municipal corporation, township, or county. The legislative authority or board shall certify a copy of the ordinance or resolution to the board of elections not less than ninety days before the day of the special election. No ordinance or resolution adopted under division (A) of this section that provides for an election under this division shall take effect unless approved by a majority of the electors voting upon the ordinance or resolution at the election held pursuant to this division.

(C) Upon the applicable requisite authority under divisions (A) and (B) of this section, the legislative authority or board shall develop a plan of operation and governance for the aggregation program so authorized. Before adopting a plan under this division, the legislative authority or board shall hold at least two public hearings on the plan. Before the first hearing, the legislative authority or board shall publish notice of the hearings once a week for two consecutive weeks in a newspaper of general circulation in the jurisdiction or as provided in section 7.16 of the Revised Code. The notice shall summarize the plan and state the date, time, and location of each hearing.

(D) No legislative authority or board, pursuant to an ordinance or resolution under divisions (A) and (B) of this section that provides for automatic aggregation of customers that are not mercantile customers as described in division (A) of this section, shall aggregate the electrical load of any electric load center located within its jurisdiction unless it in advance clearly discloses to the person owning, occupying, controlling, or using the load center that the person will be enrolled automatically in the aggregation program and will remain so enrolled unless the person affirmatively elects by a stated procedure not to be so enrolled. The disclosure shall state prominently the rates, charges, and other terms and conditions of enrollment. The stated procedure shall allow any person enrolled in the aggregation program the opportunity to opt out of the program every three years, without paying a switching fee. Any such person that opts out before the commencement of the aggregation program pursuant to the stated procedure shall default to the standard service offer provided under section 4928.14 or division (D) of section 4928.35 of the Revised Code until the person chooses an alternative supplier.

(E)

(1) With respect to a governmental aggregation for a municipal corporation that is authorized pursuant to divisions (A) to (D) of this section, resolutions may be proposed by initiative or referendum petitions in accordance with sections 731.28 to 731.41 of the Revised Code.

(2) With respect to a governmental aggregation for a township or the unincorporated area of a county, which aggregation is authorized pursuant to divisions (A) to (D) of this section, resolutions may be proposed by initiative or referendum petitions in accordance with sections 731.28 to 731.40 of the Revised Code, except that:

(a) The petitions shall be filed, respectively, with the township fiscal officer or the board of county commissioners, who shall perform those duties imposed under those sections upon the city auditor or village clerk.

(b) The petitions shall contain the signatures of not less than ten per cent of the total number of electors in, respectively, the township or the unincorporated area of the county who voted for the office of governor at the preceding general election for that office in that area.

(F) A governmental aggregator under division (A) of this section is not a public utility engaging in the wholesale purchase and resale of electricity, and provision of the aggregated service is not a wholesale utility transaction. A governmental aggregator shall be subject to supervision and regulation by the public utilities commission only to the extent of any competitive retail electric service it provides and commission authority under this chapter.

(G) This section does not apply in the case of a municipal corporation that supplies such aggregated service to electric load centers to which its municipal electric utility also supplies a noncompetitive retail electric service through transmission or distribution facilities the utility singly or jointly owns or operates.

(H) A governmental aggregator shall not include in its aggregation the accounts of any of the following:

(1) A customer that has opted out of the aggregation;

(2) A customer in contract with a certified electric services company;

(3) A customer that has a special contract with an electric distribution utility;

(4) A customer that is not located within the governmental aggregator's governmental boundaries;

(5) Subject to division (C) of section 4928.21 of the Revised Code, a customer who appears on the "do not aggregate" list maintained under that section.

(I) Customers that are part of a governmental aggregation under this section shall be responsible only for such portion of a surcharge under section 4928.144 of the Revised Code that is proportionate to the benefits, as determined by the commission, that electric load centers within the jurisdiction of the governmental aggregation as a group receive. The proportionate surcharge so established shall apply to each customer of the governmental aggregation while the customer is part of that aggregation. If a customer ceases being such a customer, the otherwise applicable surcharge shall apply. Nothing in this section shall result in less than full recovery by an electric distribution utility of any surcharge authorized under section 4928.144 of the Revised Code. Nothing in this section shall result in less than the full and timely imposition, charging, collection, and adjustment by an electric distribution utility, its assignee, or any collection agent, of the phase-in-recovery charges authorized pursuant to a final financing order issued pursuant to sections 4928.23 to 4928.2318 of the Revised Code.

(J) On behalf of the customers that are part of a governmental aggregation under this section and by filing written notice with the public utilities commission, the legislative authority that formed or is forming that governmental aggregation may elect not to receive standby service within the meaning of division (B)(2)(d) of section 4928.143 of the Revised Code from an electric distribution utility in whose certified territory the governmental aggregation is located and that operates under an approved electric security plan under that section. Upon the filing of that notice, the electric distribution utility shall not charge any such customer to whom competitive retail electric generation service is provided by another supplier under the governmental aggregation for the standby service. Any such consumer that returns to the utility for competitive retail electric service shall pay the market price of power incurred by the utility to serve that consumer plus any amount attributable to the utility's cost of compliance with the renewable energy resource provisions of section 4928.64 of the Revised Code to serve the consumer. Such market price shall include, but not be limited to, capacity and energy charges; all charges associated with the provision of that power supply through the regional transmission organization, including, but not limited to, transmission, ancillary services, congestion, and settlement and administrative charges; and all other costs incurred by the utility that are associated with the procurement, provision, and administration of that power supply, as such costs may be approved by the commission. The period of time during which the market price and renewable energy resource amount shall be so assessed on the consumer shall be from the time the consumer so returns to the electric distribution utility until the expiration of the electric security plan. However, if that period of time is expected to be more than two years, the commission may reduce the time period to a period of not less than two years.

(K) 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.

Cite as R.C. § 4928.20

Amended by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

Amended by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

Amended by 129th General AssemblyFile No.28, HB 153, §101.01, eff. 9/29/2011.

Amended by 128th General AssemblyFile No.29, HB 48, §1, eff. 7/2/2010.

Effective Date: 06-15-2000; 12-20-2005; 07-04-2006; 2008 SB221 07-31-2008; 2008 HB562 09-22-2008

4928.21 Do not aggregate list - registration - removal of current enrollee.

(A) A customer that desires to remove itself from the pool of customers eligible to participate in governmental aggregation under section 4928.20 of the Revised Code may register with the public utilities commission to appear on the "do not aggregate" list.

(B) The commission, by rule, shall establish a "do not aggregate" list. The commission shall maintain the "do not aggregate" list and make it publicly available on the commission's web site.

(C) If a customer is enrolled in a governmental aggregation program at the time the customer first appears on the "do not aggregate" list, the governmental aggregator shall remove the customer from the program at the next two-year opt out opportunity that is available to the customer under division (D) of section 4928.20 of the Revised Code.

Cite as R.C. § 4928.21

Effective Date: 07-04-2006

4928.23 Definitions for standards for securitization of costs for electric distribution utilities.

As used in sections 4928.23 to 4928.2318 of the Revised Code:

(A) "Ancillary agreement" means any bond insurance policy, letter of credit, reserve account, surety bond, swap arrangement, hedging arrangement, liquidity or credit support arrangement, or other similar agreement or arrangement entered into in connection with the issuance of phase-in-recovery bonds that is designed to promote the credit quality and marketability of the bonds or to mitigate the risk of an increase in interest rates.

(B) "Assignee" means any person or entity to which an interest in phase-in-recovery property is sold, assigned, transferred, or conveyed, other than as security, and any successor to or subsequent assignee of such a person or entity.

(C) "Bond" includes debentures, notes, certificates of participation, certificates of beneficial interest, certificates of ownership or other evidences of indebtedness or ownership that are issued by an electric distribution utility or an assignee under a final financing order, the proceeds of which are used directly or indirectly to recover, finance, or refinance phase-in costs and financing costs, and that are secured by or payable from revenues from phase-in-recovery charges.

(D) "Bondholder" means any holder or owner of a phase-in-recovery bond.

(E) "Financing costs" means any of the following:

(1) Principal, interest, and redemption premiums that are payable on phase-in-recovery bonds;

(2) Any payment required under an ancillary agreement;

(3) Any amount required to fund or replenish a reserve account or another account established under any

indenture, ancillary agreement, or other financing document relating to phase-in-recovery bonds;

(4) Any costs of retiring or refunding any existing debt and equity securities of an electric distribution utility in connection with either the issuance of, or the use of proceeds from, phase-in-recovery bonds;

(5) Any costs incurred by an electric distribution utility to obtain modifications of or amendments to any indenture, financing agreement, security agreement, or similar agreement or instrument relating to any existing secured or unsecured obligation of the electric distribution utility in connection with the issuance of phase-in-recovery bonds;

(6) Any costs incurred by an electric distribution utility to obtain any consent, release, waiver, or approval from any holder of an obligation described in division (E)(5) of this section that are necessary to be incurred for the electric distribution utility to issue or cause the issuance of phase-in-recovery bonds;

(7) Any taxes, franchise fees, or license fees imposed on phase-in-recovery revenues;

(8) Any costs related to issuing or servicing phase-in-recovery bonds or related to obtaining a financing order, including servicing fees and expenses, trustee fees and expenses, legal, accounting, or other professional fees and expenses, administrative fees, placement fees, underwriting fees, capitalized interest and equity, and rating-agency fees;

(9) Any other similar costs that the public utilities commission finds appropriate.

(F) "Financing order" means an order issued by the public utilities commission under section 4928.232 of the Revised Code that authorizes an electric distribution utility or an assignee to issue phase-in-recovery bonds and recover phase-in-recovery charges.

(G) "Final financing order" means a financing order that has become final and has taken effect as provided in section 4928.233 of the Revised Code.

(H) "Financing party" means either of the following:

(1) Any trustee, collateral agent, or other person acting for the benefit of any bondholder;

(2) Any party to an ancillary agreement, the rights and obligations of which relate to or depend upon the existence of phase-in-recovery property, the enforcement and priority of a security interest in phase-in-recovery property, the timely collection and payment of phase-in-recovery revenues, or a combination of these factors.

(I) "Financing statement" has the same meaning as in section 1309.102 of the Revised Code.

(J) "Phase-in costs" means costs, inclusive of carrying charges incurred before, on, or after the effective date of this section, authorized by the commission before, on, or after the effective date of this section to be securitized or deferred as regulatory assets in proceedings under section 4909.18 of the Revised Code, sections 4928.141 to 4928.143 , or 4928.144 of the Revised Code, or section 4928.14 of the Revised Code as it existed prior to July 31, 2008, pursuant to a final order for which appeals have been exhausted. "Phase-in costs" excludes the following:

(1) With respect to any electric generating facility that, on and after the effective date of this section, is owned, in whole or in part, by an electric distribution utility applying for a financing order under section 4928.231 of the Revised Code, costs that are authorized under division (B)(2)(b) or (c) of section 4928.143 of the Revised Code;

(2) Costs incurred after the effective date of this section related to the ongoing operation of an electric generating facility, but not environmental clean-up or remediation costs incurred by an electric distribution utility because of its ownership or operation of an electric generating facility prior to the effective date of this section, which such clean-up or remediation costs are imposed or incurred pursuant to federal or state law rules, or regulations and for which the commission approves recovery in accordance with section 4909.18 of the Revised Code, sections 4928.141 to 4928.143 , or 4928.144 of the Revised Code, or section 4928.14 of the Revised Code as it existed prior to July 31, 2008.

(K) "Phase-in-recovery property" means the property, rights, and interests of an electric distribution utility or an assignee under a final financing order, including the right to impose, charge, and collect the phase-in-recovery charges that shall be used to pay and secure the payment of phase-in-recovery bonds and financing costs, and including the right to obtain adjustments to those charges, and any revenues, receipts, collections, rights to payment, payments, moneys, claims, or other proceeds arising from the rights and interests created under the final financing order.

(L) "Phase-in-recovery revenues" means all revenues, receipts, collections, payments, moneys, claims, or other proceeds arising from phase-in-recovery property.

(M) "Successor" means, with respect to any entity, another entity that succeeds by operation of law to the rights and obligations of the first legal entity pursuant to any bankruptcy, reorganization, restructuring, or other insolvency proceeding, any merger, acquisition, or consolidation, or any sale or transfer of assets, regardless of whether any of these occur as a result of a restructuring of the electric power industry or otherwise.

Cite as R.C. § 4928.23

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.231 Financing order for issuance of bonds to recover phase-in costs and carrying charges.

(A) An electric distribution utility may apply to the public utilities commission for a financing order that authorizes the following:

(1) The issuance of phase-in-recovery bonds, in one or more series, to recover uncollected phase-in costs;

(2) The imposition, charging, and collection of phase-in-recovery charges, in accordance with the adjustment mechanism approved by the commission under section 4928.232 of the Revised Code, and consistent with the commission's authority regarding governmental aggregation as provided in division (I) of section 4928.20 of the Revised Code, to recover both of the following:

(a) Uncollected phase-in costs;

(b) Financing costs.

(3) The creation of phase-in-recovery property under the financing order.

(B) The application shall include all of the following:

(1) A description of the uncollected phase-in costs that the electric distribution utility seeks to recover through the issuance of phase-in-recovery bonds;

(2) An estimate of the date each series of phase-in-recovery bonds are expected to be issued;

(3) The expected term during which the phase-in costs associated with the issuance of each series of phase-in-recovery bonds are expected to be recovered;

(4) An estimate of the financing costs, as described in section 4928.23 of the Revised Code, associated with the issuance of each series of phase-in-recovery bonds;

(5) An estimate of the amount of phase-in-recovery charges necessary to recover the phase-in costs and financing costs set forth in the application and the calculation for that estimate, which calculation shall take into account the estimated date or dates of issuance and the estimated principal amount of each series of phase-in-recovery bonds;

(6) For phase-in-recovery charges not subject to allocation according to an existing order, a proposed methodology for allocating phase-in-recovery charges among customer classes, including a proposed methodology for allocating such charges to governmental aggregation customers based upon the proportionate benefit determination made under division (I) of section 4928.20 of the Revised Code;

(7) A description of a proposed adjustment mechanism for use as described in division (A)(2) of this section;

(8) A description and valuation of how the issuance of the phase-in-recovery bonds, including financing costs, will both result in cost savings to customers and mitigate rate impacts to customers when compared to the use of other financing mechanisms or cost-recovery methods available to the electric distribution utility;

(9) Any other information required by the commission.

(C) The electric distribution utility may restate or incorporate by reference in the application any information required under division (B)(9) of this section that the electric distribution utility filed with the commission under section 4909.18 or sections 4928.141 to 4928.144 of the Revised Code or section 4928.14 of the Revised Code as it existed prior to July 31, 2008.

Cite as R.C. § 4928.231

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.232 Proceedings; review of application; disposition.

(A) Proceedings before the public utilities commission on an application submitted by an electric distribution utility under section 4928.231 of the Revised Code shall be governed by Chapter 4903. of the Revised Code, but only to the extent that chapter is not inconsistent with this section or section 4928.233 of the Revised Code. Any party that participated in the proceeding in which phase-in costs were approved under section 4909.18 or sections 4928.141 to 4928.144 of the Revised Code or section 4928.14 of the Revised Code as it existed prior to July 31, 2008, shall have standing to participate in proceedings under sections 4928.23 to 4928.2318 of the Revised Code.

(B) When reviewing an application for a financing order pursuant to sections 4928.23 to 4928.2318 of the Revised Code, the commission may hold such hearings, make such inquiries or investigations, and examine such witnesses, books, papers, documents, and contracts as the commission considers proper to carry out these sections. Within thirty days after the filing of an application under section 4928.231 of the Revised Code, the commission shall publish a schedule of the proceeding.

(C)

(1) Not later than one hundred thirty-five days after the date the application is filed, the commission shall issue either a financing order, granting the application in whole or with modifications, or an order suspending or rejecting the application.

(2) If the commission suspends an application for a financing order, the commission shall notify the electric distribution utility of the suspension and may direct the electric distribution utility to provide additional information as the commission considers necessary to evaluate the application. Not later than ninety days after the suspension, the commission shall issue either a financing order, granting the application in whole or with modifications, or an order rejecting the application.

(D)

(1) The commission shall not issue a financing order under division (C) of this section unless the commission determines that the financing order is consistent with section 4928.02 of the Revised Code.

(2) Except as provided in division (D)(1) of this section, the commission shall issue a financing order under division (C) of this section if, at the time the financing order is issued, the commission finds that the issuance of the phase-in-recovery bonds and the phase-in-recovery charges authorized by the order results in, consistent with market conditions, both measurably enhancing cost savings to customers and mitigating rate impacts to customers as compared with traditional financing mechanisms or traditional cost-recovery methods available to the electric distribution utility or, if the commission previously approved a recovery method, as compared with that recovery method.

(E) The commission shall include all of the following in a financing order issued under division (C) of this section:

(1) A determination of the maximum amount and a description of the phase-in costs that may be recovered through phase-in-recovery bonds issued under the financing order;

(2) A description of phase-in-recovery property, the creation of which is authorized by the financing order;

(3) A description of the financing costs that may be recovered through phase-in-recovery charges and the period over which those costs may be recovered;

(4) For phase-in-recovery charges not subject to allocation according to an existing order, a description of the methodology and calculation for allocating phase-in-recovery charges among customer classes, including the allocation of such charges, if any, to governmental aggregation customers based upon the proportionate benefit determination made under division (I) of section 4928.20 of the Revised Code;

(5) A description of the adjustment mechanism for use in the imposition, charging, and collection of the phase-in-recovery charges;

(6) The maximum term of the phase-in-recovery bonds;

(7) Any other provision the commission considers appropriate to ensure the full and timely imposition, charging, collection, and adjustment, pursuant to an approved adjustment mechanism, of the phase-in-recovery charges described in divisions (E)(3) to (5) of this section.

(F) The commission may, in a financing order, afford the electric distribution utility flexibility in establishing the terms and conditions for the phase-in-recovery bonds to accommodate changes in market conditions, including repayment schedules, interest rates, financing costs, collateral requirements, required debt service and other reserves, and the ability of the electric distribution utility, at its option, to effect a series of issuances of phase-in-recovery bonds and correlated assignments, sales, pledges, or other transfers of phase-in-recovery property. Any changes made under this section to terms and conditions for the phase-in-recovery bonds shall be in conformance with the financing order.

(G) A financing order may provide that the creation of phase-in-recovery property shall be simultaneous with the sale of that property to an assignee as provided in the application and the pledge of the property to secure phase-in-recovery bonds.

(H) The commission shall, in a financing order, require that after the final terms of each issuance of phase-in-recovery bonds have been established, and prior to the issuance of those bonds, the electric distribution utility shall determine the resulting phase-in-recovery charges in accordance with the adjustment mechanism described in the financing order. These phase-in-recovery charges shall be final and effective upon the issuance of the phase-in-recovery bonds, without further commission action.

Cite as R.C. § 4928.232

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.233 Rehearing; when order becomes final.

(A) Any party to a proceeding under section 4928.232 of the Revised Code may apply to the public utilities commission for rehearing of an order within thirty days after the date of the issuance of the order.

(B) Within sixty days after the issuance of an order after rehearing or a decision denying an application for rehearing, any party to the proceeding may file a notice of appeal with the supreme court. Any such notice of appeal shall be served as provided for in section 4903.13 of the Revised Code.

Because delay in the determination of the appeal will delay the issuance of phase-in-recovery bonds, thereby diminishing savings to customers that might be achieved if the bonds were issued under a final financing order, the supreme court shall proceed to hear and determine the action as expeditiously as practicable and shall give the action precedence over other matters not accorded similar precedence by law.

(C) Any review on appeal for a financing order issued under section 4928.232 of the Revised Code shall be governed by Chapter 4903. of the Revised Code.

(D) If any phase-in costs are, or if any financing order is, subject to review by the commission or the supreme court, the electric distribution utility may not issue any phase-in-recovery bonds based on those costs or that financing order until all commission and appellate reviews, including any appellate review following a commission decision on remand, have been exhausted.

(E) A financing order shall become final and take effect as follows:

(1) On the expiration of the thirty-day period after the date the commission issues the financing order, if no application for rehearing is filed with the commission within that period;

(2) On the expiration of the sixty-day period after the denial of the application for rehearing, if no notice of appeal is filed with the supreme court within that period;

(3) On the expiration of the sixty-day period after the commission issues an order after rehearing that approves or modifies and approves the financing order, if no notice of appeal is filed with the supreme court within that period;

(4) On the expiration of the ten-day period after the date that the supreme court judgment entry or order that affirms or modifies and affirms a financing order is filed with the clerk, including any such order issued by the court following a commission decision on remand, if no motion for reconsideration is filed within that period;

(5) On the date the supreme court order denying a motion for reconsideration of a judgment entry or order that affirmed or modified and affirmed a financing order is filed with the clerk;

(6) On the date the supreme court judgment entry or order issued after reconsideration of a judgment entry or order that affirmed or modified and affirmed a financing order is filed with the clerk;

(7) On the applicable effective date under division (E)(1), (2), or (3) of this section regarding a financing order remanded to the commission.

Cite as R.C. § 4928.233

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.234 Phase-in-recovery property.

(A) The phase-in-recovery property created in a final financing order may be transferred, sold, conveyed, or assigned to any person or entity not affiliated with the electric distribution utility subject to the final financing order or to any affiliate of the electric distribution utility created for the limited purpose of acquiring, owning, or administering that property, issuing phase-in-recovery bonds under the final financing order, or a combination of these purposes.

(B) All or any portion of the phase-in-recovery property may be pledged to secure the payment of phase-in-recovery bonds, amounts payable to financing parties and bondholders, amounts payable under any ancillary agreement, and other financing costs.

(C) The phase-in-recovery property shall constitute an existing, present property right, notwithstanding any requirement that the imposition, charging, and collection of phase-in-recovery charges depend on the electric distribution utility continuing to deliver retail electric distribution service or continuing to perform its servicing functions relating to the collection of phase-in-recovery charges or on the level of future energy consumption. That property shall exist regardless of whether the phase-in-recovery charges have been billed, have accrued, or have been collected, and notwithstanding any requirement that the value or amount of the property is dependent on the future provision of service to customers by the electric distribution utility.

(D) All such phase-in-recovery property shall continue to exist until the phase-in-recovery bonds issued under the final financing order are paid in full and all financing costs relating to the bonds have been paid in full.

Cite as R.C. § 4928.234

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.235 Duration of final financing order.

(A)

(1) A final financing order shall remain in effect until the phase-in-recovery bonds issued under the final financing order and all financing costs related to the bonds have been paid in full.

(2) A final financing order shall remain in effect and unabated notwithstanding the bankruptcy, reorganization, or insolvency of the electric distribution utility or any affiliate of the electric distribution utility or the commencement of any judicial or nonjudicial proceeding on the final financing order.

(B) A final financing order is irrevocable and the public utilities commission may not reduce, impair, postpone, or terminate the phase-in-recovery charges authorized in the final financing order or impair the property or the collection or recovery of phase-in costs.

(C)

(1) Except as provided in division (C)(2) of this section, under a final financing order, the electric distribution utility retains sole discretion regarding whether to assign, sell, or otherwise transfer phase-in-recovery property, or to cause phase-in-recovery bonds to be issued, including the right to defer or postpone such assignment, sale, transfer, or issuance.

(2) Subsequent to a financing order being issued or becoming final and taking effect, but before phase-in-recovery bonds have been issued, if market conditions are such that customers will not realize cost savings from the issuance of the phase-in-recovery bonds, the electric distribution utility shall not proceed with the securitization under the issued or final financing order.

Cite as R.C. § 4928.235

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.236 Subsequent financing orders.

At the request of the electric distribution utility subject to a final financing order, the public utilities commission may commence a proceeding and issue a subsequent financing order that provides for retiring and refunding phase-in-recovery bonds issued under the final financing order if the commission finds that the subsequent financing order satisfies all of the requirements of section 4928.232 of the Revised Code. Effective on retirement of the refunded phase-in-recovery bonds and the issuance of new phase-in-recovery bonds, the commission shall adjust the related phase-in-recovery charges accordingly.

Cite as R.C. § 4928.236

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.237 Public utilities commission - probited acts.

(A) The public utilities commission, in exercising the commission's powers and carrying out the commission's duties regarding regulation and ratemaking, may not do any of the following:

(1) Consider phase-in-recovery bonds issued under a final financing order to be the debt of the electric distribution utility subject to the final financing order;

(2) Consider the phase-in-recovery charges imposed, charged, or collected under the final financing order to be revenue of the electric distribution utility;

(3) Consider the phase-in costs or financing costs authorized under the final financing order to be the costs of the electric distribution utility.

(B) The commission may not order or otherwise require, directly or indirectly, any electric distribution utility to use phase-in-recovery bonds to finance the recovery of phase-in costs.

(C) The commission may not refuse to allow the recovery of phase-in costs solely because the electric distribution utility has elected or may elect to finance those costs through a financing mechanism other than the issuance of phase-in-recovery bonds.

If the electric distribution utility elects not to finance those costs through the issuance of phase-in-recovery bonds as authorized in the final financing order, those costs shall be recovered as authorized by the commission prior to the application for the financing order.

Cite as R.C. § 4928.237

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.238 Request for approval of adjustments to charges.

(A) An electric distribution utility subject to a final financing order shall file with the public utilities commission, at least annually, or more frequently as provided in the final financing order, a schedule applying the approved adjustment mechanism to the phase-in-recovery charges authorized under the final financing order, based on estimates of consumption for each customer class and other mathematical factors. The electric distribution utility shall submit with the schedule a request for approval to make the adjustments to the phase-in-recovery charges in accordance with the schedule.

(B) The commission's review of the request shall be limited to a determination of whether there is any mathematical error in the application of the adjustment mechanism to the phase-in-recovery charges, including the calculation of any proportionate charges allocated to governmental aggregation customers as directed in the final financing order.

(C) A request submitted under division (A) of this section shall be deemed approved, and the adjustments shall go into immediate effect, if not approved by the commission within sixty days after the request is submitted.

(D) No adjustment approved or deemed approved under this section shall in any way affect the irrevocability of the final financing order as specified in section 4928.235 of the Revised Code.

Cite as R.C. § 4928.238

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.239 Nonbypassable charges; collection.

(A) As used in this section, "nonbypassable," with respect to phase-in-recovery charges, means that such charges cannot be avoided by any customer or other person obligated to pay the charges.

(B)

(1) As long as phase-in-recovery bonds issued under a final financing order are outstanding and the related phase-in costs and financing costs have not been recovered in full, the phase-in-recovery charges authorized under the final financing order shall be nonbypassable. Subject to the methodology approved in the final financing order pursuant to division (E)(4) of section 4928.232 of the Revised Code, phase-in-recovery charges shall apply to all customers of the electric distribution utility for as long as they remain customers of the electric distribution utility, except as provided in division (B)(2) of this section. If a customer of the electric distribution utility purchases electric generation service from a competitive retail electric service provider, the electric distribution utility shall collect the phase-in-recovery charges directly

from that customer.

(2) If a customer of the electric distribution utility subsequently receives retail electric distribution service from another electric distribution utility operating in the same service area, including by succession, assignment, transfer, or merger, the phase-in-recovery charges shall continue to apply to that customer.

(C) The phase-in-recovery charges shall be collected by the electric distribution utility or the electric distribution utility's successors or assignees, or a collection agent, in full through a charge that is separate and apart from the electric distribution utility's base rates.

Cite as R.C. § 4928.239

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.2310 Default; sequestration and payment of revenues for benefit of bondholders, assignees, and financing parties.

(A)

(1) If an electric distribution utility subject to a final financing order defaults on any required payment of phase-in-recovery revenues, a court, upon application by an interested party and without limiting any other remedies available to the applicant, shall order the sequestration and payment of the revenues for the benefit of bondholders, any assignee, and any financing parties. The court order shall remain in full force and effect notwithstanding any bankruptcy, reorganization, or other insolvency proceedings with respect to the electric distribution utility or any affiliate.

(2) Notwithstanding division (A)(1) of this section, customers of an electric distribution utility shall be held harmless for the electric distribution utility's failure to remit any required payment of phase-in-recovery revenues, and such failure shall in no way affect the phase-in-recovery property or the rights to impose, collect, and adjust the phase-in-recovery charges under sections 4928.23 to 4928.2318 of the Revised Code.

(B) Phase-in-recovery property under a final financing order and the interests of an assignee, bondholder, or financing party in that property under a financing agreement are not subject to setoff, counterclaim, surcharge, or defense by the electric distribution utility subject to the final financing order or any other person, including as a result of the electric distribution utility's failure to provide past, present, or future services, or in connection with the bankruptcy, reorganization, or other insolvency proceeding of the electric distribution utility, any affiliate, or any other entity.

Cite as R.C. § 4928.2310

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.2311 Successors.

Any successor to an electric distribution utility subject to a final financing order shall be bound by the requirements of sections 4928.23 to 4928.2317 of the Revised Code. The successor shall perform and satisfy all obligations of the electric distribution utility under the final financing order, in the same manner and to the same extent as the electric distribution utility, including the obligation to collect and pay phase-in-recovery revenues to the person entitled to receive those revenues. The successor shall have the same rights of the electric distribution utility under the final financing order, in the same manner and to the same extent as the electric distribution utility.

Cite as R.C. § 4928.2311

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.2312 Security interest in phase-in-recovery property.

(A) Except as provided in division (C) of this section, the creation, perfection, and enforcement of any security interest in phase-in-recovery property under a final financing order to secure the repayment of the principal of and interest on phase-in-recovery bonds, amounts payable under any ancillary agreement, and other financing costs are governed by this section and not Chapters 1301. to 1309. of the Revised Code.

(B) The description of the phase-in-recovery property in a transfer or security agreement and a financing statement is sufficient only if the description refers to this section and the final financing order creating the property. This section applies to all purported transfers of, and all purported grants of, liens on or security interests in that property, regardless of whether the related transfer or security agreement was entered into, or the related financing statement was filed, before or after the effective date of this section.

(C)

(1) A security interest in phase-in-recovery property under a final financing order is created, valid, and binding at the latest of the date that the security agreement is executed and delivered or the date that value is received for the phase-in-recovery bonds.

(2)

(a) The security interest shall attach without any physical delivery of collateral or other act, and, upon the filing of the financing statement with the office of the secretary of state, the lien of the security interest shall be valid, binding, and perfected against all parties having claims of any kind in tort, contract, or otherwise against the person granting the security interest, regardless of whether the parties have notice of the lien. Also upon this filing, a transfer of an interest in the phase-in-recovery property shall be perfected against all parties having claims of any kind, including any judicial lien or other lien creditors or any claims of the seller or creditors of the seller, other than creditors holding a prior security interest, ownership interest, or assignment in the property previously perfected in accordance with this division.

(b) The secretary of state shall maintain any financing statement filed under division (C)(2) of this section in the same manner that the secretary maintains financing statements filed by transmitting utilities under division (B) of section 1309.501 of the Revised Code. The filing of any financing statement under division (C)(2) of this section shall be governed by the provisions regarding the filing of financing statements in Chapter 1309. of the Revised Code.

(D)

(1) A security interest in phase-in-recovery property under a final financing order is a continuously perfected security interest and has priority over any other lien, created by operation of law or otherwise, that may subsequently attach to that property or those rights or interests unless the holder of any such lien has agreed in writing otherwise.

(2) The priority of a security interest in phase-in-recovery property is not affected by the commingling of phase-in-recovery revenues with other amounts. Any pledgee or secured party shall have a perfected security interest in the amount of all phase-in-recovery revenues that are deposited in any cash or deposit account of the electric distribution utility in which phase-in-recovery revenues have been commingled with

other funds. Any other security interest that may apply to those funds shall be terminated when the funds are transferred to a segregated account for an assignee or a financing party.

(3) No application of the adjustment mechanism as described in section 4928.238 of the Revised Code shall affect the validity, perfection, or priority of a security interest in or the transfer of phase-in-recovery property under the final financing order.

Cite as R.C. § 4928.2312

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.2313 Sale, assignment, or transfer of phase-in-recovery property.

(A) Any sale, assignment, or transfer of phase-in-recovery property under a final financing order shall be an absolute transfer and true sale of, and not a pledge of or secured transaction relating to, the seller's right, title, and interest in, to, and under the property, if the documents governing the transaction expressly state that the transaction is a sale or other absolute transfer. A transfer of an interest in that property may be created only when all of the following have occurred:

(1) The financing order has become final and taken effect.

(2) The documents evidencing the transfer of the property have been executed and delivered to the assignee.

(3) Value has been received for the property.

(B) The characterization of the sale, assignment, or transfer as an absolute transfer and true sale and the corresponding characterization of the property interest of the purchaser shall be effective and perfected against all third parties and shall not be affected or impaired by, among other things, the occurrence of any of the following:

(1) Commingling of phase-in-recovery revenues with other amounts;

(2) The retention by the seller of either of the following:

(a) A partial or residual interest, including an equity interest, in the phase-in-recovery property, whether direct or indirect, or whether subordinate or otherwise;

(b) The right to recover costs associated with taxes, franchise fees, or license fees imposed on the collection of phase-in-recovery revenues.

(3) Any recourse that the purchaser or any assignee may have against the seller;

(4) Any indemnification rights, obligations, or repurchase rights made or provided by the seller;

(5) The obligation of the seller to collect phase-in-recovery revenues on behalf of an assignee;

(6) The treatment of the sale, assignment, or transfer for tax, financial reporting, or other purposes;

(7) Any application of the adjustment mechanism under the final financing order.

Cite as R.C. § 4928.2313

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.2314 Exemption from taxes and other charges.

(A) The transfer and ownership of phase-in-recovery property and the imposition, charging, collection, and receipt of phase-in-recovery revenues under sections 4928.231 to 4928.2317 of the Revised Code are exempt from all taxes and similar charges imposed by the state or any county, municipal corporation, school district, local authority, or other subdivision.

(B) Phase-in-recovery bonds issued under a final financing order shall not constitute a debt or a pledge of the faith and credit or taxing power of this state or of any county, municipal corporation, or any other political subdivision of this state. Bondholders shall have no right to have taxes levied by this state or the taxing authority of any county, municipal corporation, or any other political subdivision of this state for the payment of the principal of or interest on the bonds. The issuance of phase-in-recovery bonds does not, directly, indirectly, or contingently, obligate this state or any county, municipal corporation, or political subdivision of this state to levy any tax or make any appropriation for payment of the principal of or interest on the bonds.

(C) Nothing in this section prohibits the levy of the tax imposed under Chapter 5751. of the Revised Code.

Cite as R.C. § 4928.2314

Amended by 129th General AssemblyFile No.125, SB 315, §101.01, eff. 9/10/2012.

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.2315 Prohibition of state interference.

(A) The state pledges to and agrees with the bondholders, any assignee, and any financing parties under a final financing order that the state will not take or permit any action that impairs the value of phase-in-recovery property under the final financing order or revises the phase-in costs for which recovery is authorized under the final financing order or, except as allowed under section 4928.238 of the Revised Code, reduce, alter, or impair phase-in-recovery charges that are imposed, charged, collected, or remitted for the benefit of the bondholders, any assignee, and any financing parties, until any principal, interest, and redemption premium in respect of phase-in-recovery bonds, all financing costs, and all amounts to be paid to an assignee or financing party under an ancillary agreement are paid or performed in full.

(B) Any person who issues phase-in-recovery bonds is permitted to include the pledge specified in division (A) of this section in the phase-in-recovery bonds, ancillary agreements, and documentation related to the issuance and marketing of the phase-in-recovery bonds.

Cite as R.C. § 4928.2315

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.2316 Governing law.

(A) The law governing the validity, enforceability, attachment, perfection, priority, and exercise of remedies with respect to the transfer of phase-in-recovery property under a final financing order, or creation of a security interest in any such property, phase-in-recovery charges, or final financing order shall be the laws of this state as set forth in sections 4928.23 to 4928.2318 of the Revised Code.

(B) This section shall control in the event of a conflict between sections 4928.23 to 4928.2317 of the Revised Code and any other law regarding the attachment, assignment, or perfection, the effect of perfection, or priority of any security interest in or transfer of phase-in-recovery property under a final financing order.

Cite as R.C. § 4928.2316

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.2317 Repealed laws have no effect on actions taken.

If any provision of sections 4928.23 to 4928.2318 of the Revised Code is held to be invalid or is superseded, replaced, repealed, or expires for any reason, that occurrence shall not affect any action allowed under those sections that is taken prior to that occurrence by the public utilities commission, an electric distribution utility, an assignee, a collection agent, a financing party, a bondholder, or a party to an ancillary agreement. Any such action shall remain in full force and effect.

Cite as R.C. § 4928.2317

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.2318 Assignee or financing party not considered an electric distribution utility.

An assignee or financing party shall not be considered an electric distribution utility or person providing electric service by virtue of engaging in the transactions described in sections 4928.23 to 4928.2313 of the Revised Code.

Cite as R.C. § 4928.2318

Added by 129th General AssemblyFile No.61, HB 364, §1, eff. 3/22/2012.

4928.24 Federal energy advocate, duties.

The public utilities commission shall employ a federal energy advocate to monitor the activities of the federal energy regulatory commission and other federal agencies and to advocate on behalf of the interests of retail electric service consumers in this state. The attorney general shall represent the advocate before the federal energy regulatory commission and other federal agencies. Among other duties assigned to the advocate by the commission, the advocate shall examine the value of the participation of this state's electric utilities in regional transmission organizations and submit a report to the public utilities commission on whether continued participation of those utilities is in the interest of those consumers.

Cite as R.C. § 4928.24

Effective Date: 2008 SB221 07-31-2008

4928.31 Transition plan.

(A) Not later than ninety days after the effective date of this section, an electric utility supplying retail electric service in this state on that date shall file with the public utilities commission a plan for the utility's provision of retail electric service in this state during the market development period. This transition plan shall be in such form as the commission shall prescribe by rule adopted under division (A) of section 4928.06 of the Revised Code and shall include all of the following:

(1) A rate unbundling plan that specifies, consistent with divisions (A)(1) to (7) of section 4928.34 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the

Revised Code, the unbundles components for electric generation, transmission, and distribution service and such other unbundled service components as the commission requires, to be charged by the utility beginning on the starting date of competitive retail electric service and that includes information the commission requires to fix and determine those components;

(2) A corporate separation plan consistent with section 4928.17 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code;

(3) Such plan or plans as the commission requires to address operational support systems and any other technical implementation issues pertaining to competitive retail electric service consistent with any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code;

(4) An employee assistance plan for providing severance, retraining, early retirement, retention, outplacement, and other assistance for the utility's employees whose employment is affected by electric industry restructuring under this chapter;

(5) A consumer education plan consistent with former section 4928.42 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code. A transition plan under this section may include tariff terms and conditions to address reasonable requirements for changing suppliers, length of commitment by a customer for service, and such other matters as are necessary to accommodate electric restructuring. Additionally, a transition plan under this section may include an application for the opportunity to receive transition revenues as authorized under sections 4928.31 to 4928.40 of the Revised Code, which application shall be consistent with those sections and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code. The transition plan also may include a plan for the independent operation of the utility's transmission facilities consistent with section 4928.12 of the Revised Code, division (A)(13) of section 4928.34 of the Revised Code, and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code. The commission may reject and require refiling, in whole or in part, of any substantially inadequate transition plan.

(B) The electric utility shall provide public notice of its filing under division (A) of this section, in a form and manner that the commission shall prescribe by rule adopted under division (A) of section 4928.06 of the Revised Code. However, the adoption of rules regarding the public notice under this division, regarding the form of the transition plan under division (A) of this section, and regarding procedures for expedited discovery under division (A) of section 4928.32 of the Revised Code are not subject to division (D) of section 111.15 of the Revised Code.

Cite as R.C. § 4928.31

Effective Date: 10-05-1999; 2008 SB221 07-31-2008

4928.32 Procedures for expedited discovery in proceeding initiated to consider transition plan.

(A) The public utilities commission shall establish reasonable procedures for expedited discovery in any proceeding initiated to consider a transition plan filed under section 4928.31 of the Revised Code.

(B) Not later than forty-five days after the date on which an electric utility files a transition plan under section 4928.31 of the Revised Code, any person having a real and substantial interest in the transition plan may file with the commission preliminary objections to the transition plan, which shall identify with specificity issues pertaining to any aspect of the transition plan, and any such person may propose specific responses to those issues. The commission shall address those objections and responses in its final order. In addition, not later than ninety days after the plan's filing, the commission staff shall file with the commission a report of its recommendations with respect to the plan. Prior to commission approval of the plan, the commission shall afford a hearing upon those aspects of the plan that the commission determines reasonably require a hearing.

(C) The commission shall maintain a complete record of all proceedings relative to a transition plan filed under section 4928.31 of the Revised Code and shall issue and file with the record of the case findings of fact and written opinions setting forth the reasons for any modification to or its approval of a transition plan.

Cite as R.C. § 4928.32

Effective Date: 10-05-1999

4928.33 Transition plan approval.

(A) Not later than two hundred seventy-five days after the date an electric utility files a transition plan under section 4928.31 of the Revised Code, but, in any event, not later than October 31, 2000, the public utilities commission shall issue a final order approving the transition plan as filed under section 4928.31 of the Revised Code or an order modifying and approving that plan. The order is subject to section 4903.15 of the Revised Code and is subject to review and appeal under Chapter 4903. of the Revised Code.

(B) If the commission fails to issue, by October 31, 2000, a final order approving a transition plan, or such a final order has been enjoined in whole or in part pending appeal to a court, the commission shall issue an interim order prescribing a transition plan, to have effect on an interim basis only, and containing the plan components required by division (A) of section 4928.31 of the Revised Code and providing for the opportunity for transition revenue receipt if such an application were included in the plan filed by the utility under that section. The interim order is subject to section 4903.15 of the Revised Code but is not subject to review and appeal under Chapter 4903. of the Revised Code. An interim plan prescribed under the interim order shall be effective for the electric utility beginning on the starting date of competitive retail electric service and shall continue in effect until such time as any other replacement transition plan takes effect pursuant to a final commission order or resolution of an appeal. Any interim plan so prescribed shall comply with the applicable provisions of section 4928.34 of the Revised Code. A final commission order shall provide for a reconciliation of those amounts determined in the final order relative to division (A) of section 4928.31 of the Revised Code as compared to the interim amounts as determined under this division.

(C) No electric utility required to file a transition plan under section 4928.31 of the Revised Code shall fail to implement a transition plan approved or prescribed for the utility by a commission order issued under division (A) or (B) of this section. No electric utility shall provide retail electric service in this state during the market development period except pursuant to such an approved or prescribed transition plan.

Cite as R.C. § 4928.33

Effective Date: 10-05-1999

4928.34 Determinations for approval or prescribing of plan.

(A) The public utilities commission shall not approve or prescribe a transition plan under division (A) or (B) of section 4928.33 of the Revised Code unless the commission first makes all of the following determinations:

(1) The unbundled components for the electric transmission component of retail electric service, as specified in the utility's rate unbundling plan required by division (A)(1) of section 4928.31 of the Revised Code, equal the tariff rates determined by the federal energy regulatory commission that are in effect on the date of the approval of the transition plan under sections 4928.31 to 4928.40 of the Revised Code, as each such rate is determined applicable to each particular customer class and rate schedule by the commission. The unbundled transmission component shall include a sliding scale of charges under division (B) of section 4905.31 of the Revised Code to ensure that refunds determined or approved by the federal energy regulatory commission are flowed through to retail electric customers.

(2) The unbundled components for retail electric distribution service in the rate unbundling plan equal the difference between the costs attributable to the utility's transmission and distribution rates and charges under its schedule of rates and charges in effect on the effective date of this section, based upon the record in the most recent rate proceeding of the utility for which the utility's schedule was established, and the tariff rates for electric transmission service determined by the federal energy regulatory commission as described in division (A)(1) of this section.

(3) All other unbundled components required by the commission in the rate unbundling plan equal the costs attributable to the particular service as reflected in the utility's schedule of rates and charges in effect on the effective date of this section.

(4) The unbundled components for retail electric generation service in the rate unbundling plan equal the residual amount remaining after the determination of the transmission, distribution, and other unbundled components, and after any adjustments necessary to reflect the effects of the amendment of section 5727.111 of the Revised Code by Sub. S.B. No. 3 of the 123rd general assembly.

(5) All unbundled components in the rate unbundling plan have been adjusted to reflect any base rate reductions on file with the commission and as scheduled to be in effect by December 31, 2005, under rate settlements in effect on the effective date of this section. However, all earnings obligations, restrictions, or caps imposed on an electric utility in a commission order prior to the effective date of this section are void.

(6) Subject to division (A)(5) of this section, the total of all unbundled components in the rate unbundling plan are capped and shall equal during the market development period, except as specifically provided in this chapter, the total of all rates and charges in effect under the applicable bundled schedule of the electric utility pursuant to section 4905.30 of the Revised Code in effect on the day before the effective date of this section, including the transition charge determined under section 4928.40 of the Revised Code, adjusted for any changes in the taxation of electric utilities and retail electric service under Sub. S.B. No. 3 of the 123rd General Assembly, the universal service rider authorized by section 4928.51 of the Revised Code, and the temporary rider authorized by section 4928.61 of the Revised Code. For the purpose of this division, the rate cap applicable to a customer receiving electric service pursuant to an arrangement approved by the commission under section 4905.31 of the Revised Code is, for the term of the arrangement, the total of all rates and charges in effect under the arrangement. For any rate schedule filed pursuant to section 4905.30 of the Revised Code or any arrangement subject to approval pursuant to section 4905.31 of the Revised Code, the initial tax-related adjustment to the rate cap required by this division shall be equal to the rate of taxation specified in section 5727.81 of the Revised Code and applicable to the schedule or arrangement. To the extent such total annual amount of the tax-related adjustment is greater than or less than the comparable amount of the total annual tax reduction experienced by the electric utility as a result of the provisions of Sub. S.B. No. 3 of the 123rd general

assembly, such difference shall be addressed by the commission through accounting procedures, refunds, or an annual surcharge or credit to customers, or through other appropriate means, to avoid placing the financial responsibility for the difference upon the electric utility or its shareholders. Any adjustments in the rate of taxation specified in 5727.81 of the Revised Code section shall not occur without a corresponding adjustment to the rate cap for each such rate schedule or arrangement. The department of taxation shall advise the commission and self-assessors under section 5727.81 of the Revised Code prior to the effective date of any change in the rate of taxation specified under that section, and the commission shall modify the rate cap to reflect that adjustment so that the rate cap adjustment is effective as of the effective date of the change in the rate of taxation. This division shall be applied, to the extent possible, to eliminate any increase in the price of electricity for customers that otherwise may occur as a result of establishing the taxes contemplated in section 5727.81 of the Revised Code.

(7) The rate unbundling plan complies with any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code.

(8) The corporate separation plan required by division (A)(2) of section 4928.31 of the Revised Code complies with section 4928.17 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code.

(9) Any plan or plans the commission requires to address operational support systems and any other technical implementation issues pertaining to competitive retail electric service comply with any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code.

(10) The employee assistance plan required by division (A)(4) of section 4928.31 of the Revised Code sufficiently provides severance, retraining, early retirement, retention, outplacement, and other assistance for the utility's employees whose employment is affected by electric industry restructuring under this chapter.

(11) The consumer education plan required under division (A)(5) of section 4928.31 of the Revised Code complies with former section 4928.42 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code.

(12) The transition revenues for which an electric utility is authorized a revenue opportunity under sections 4928.31 to 4928.40 of the Revised Code are the allowable transition costs of the utility as such costs are determined by the commission pursuant to section 4928.39 of the Revised Code, and the transition charges for the customer classes and rate schedules of the utility are the charges determined pursuant to section 4928.40 of the Revised Code.

(13) Any independent transmission plan included in the transition plan filed under section 4928.31 of the Revised Code reasonably complies with section 4928.12 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code, unless the commission, for good cause shown, authorizes the utility to defer compliance until an order is issued under division (G) of section 4928.35 of the Revised Code.

(14) The utility is in compliance with sections 4928.01 to 4928.11 of the Revised Code and any rules or orders of the commission adopted or issued under those sections.

(15) All unbundled components in the rate unbundling plan have been adjusted to reflect the elimination of the tax on gross receipts imposed by section 5727.30 of the Revised Code. In addition, a transition plan approved by the commission under section 4928.33 of the Revised Code but not containing an approved independent transmission plan shall contain the express conditions that the utility will comply with an

order issued under division (G) of section 4928.35 of the Revised Code.

(B) Subject to division (E) of section 4928.17 of the Revised Code, if the commission finds that any part of the transition plan would constitute an abandonment under sections 4905.20 and 4905.21 of the Revised Code, the commission shall not approve that part of the transition plan unless it makes the finding required for approval of an abandonment application under section 4905.21 of the Revised Code. Sections 4905.20 and 4905.21 of the Revised Code otherwise shall not apply to a transition plan under sections 4928.31 to 4928.40 of the Revised Code.

Cite as R.C. § 4928.34

Effective Date: 10-05-1999; 2008 SB221 07-31-2008

4928.35 Schedules containing unbundled rate components set in approved plan.

(A) Upon approval of its transition plan under sections 4928.31 to 4928.40 of the Revised Code, an electric utility shall file in accordance with section 4905.30 of the Revised Code schedules containing the unbundled rate components set in the approved plan in accordance with section 4928.34 of the Revised Code. The schedules shall be in effect for the duration of the utility's market development period, shall be subject to the cap specified in division (A)(6) of section 4928.34 of the Revised Code, and shall not be adjusted during that period by the public utilities commission except as otherwise authorized by division (B) of this section or as otherwise authorized by federal law or except to reflect any change in tax law or tax regulation that has a material effect on the electric utility.

(B) Efforts shall be made to reach agreements with electric utilities in matters of litigation regarding property valuation issues. Irrespective of those efforts, the unbundled components for an electric utility's retail electric generation service and distribution service, as provided in division (A) of this section, are not subject to adjustment for the utility's market development period, except that the commission shall order an equitable reduction in those components for all customer classes to reflect any refund a utility receives as a result of the resolution of utility personal property tax valuation litigation that is resolved on or after the effective date of this section and not later than December 31, 2005. Immediately upon the issuance of that order, the electric utility shall file revised rate schedules under section 4909.18 of the Revised Code to effect the order.

(C) The schedule under division (A) of this section containing the unbundled distribution components shall provide that electric distribution service under the schedule will be available to all retail electric service customers in the electric utility's certified territory and their suppliers on a nondiscriminatory and comparable basis on and after the starting date of competitive retail electric service. The schedule also shall 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 commission.

(D) During the market development period, an electric distribution utility shall provide consumers on a comparable and nondiscriminatory basis within its certified territory a 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 priced in accordance with the schedule containing the utility's unbundled generation service component. Immediately upon approval of its transition plan, the utility shall file the standard service offer with the commission under section 4909.18 of the Revised Code, during the market development period. The failure of a supplier to deliver retail electric generation service shall result in the supplier's customers, after reasonable notice, defaulting to the utility's standard service offer filed under this division until the customer chooses an alternative supplier. A supplier is deemed under this section to have failed to deliver such service if any of the conditions specified in section 4928.14 of the Revised Code is met.

(E) An amendment of a corporate separation plan contained in a transition plan approved by the commission under section 4928.33 of the Revised Code shall be filed and approved as a corporate separation plan pursuant to section 4928.17 of the Revised Code.

(F) Any change to an electric utility's opportunity to receive transition revenues under a transition plan approved in accordance with section 4928.33 of the Revised Code shall be authorized only as provided in sections 4928.31 to 4928.40 of the Revised Code.

(G) The commission, by order, shall require each electric utility whose approved transition plan did not include an independent transmission plan as described in division (A)(13) of section 4928.34 of the Revised Code to be a member of, and transfer control of transmission facilities it owns or controls in this state to, one or more qualifying transmission entities, as described in division (B) of section 4928.12 of the Revised Code, that are planned to be operational on and after December 31, 2003. However, the commission may extend that date if, for reasons beyond the control of the utility, a qualifying transmission entity is not planned to be operational on that date. The commission's order may specify an earlier date on which the transmission entity or entities are planned to be operational if the commission considers it necessary to carry out the policy specified in section 4928.02 of the Revised Code or to encourage effective competition in retail electric service in this state. Upon the issuance of the order, each such utility shall file with the commission a plan for such independent operation of the utility's transmission facilities consistent with this division. The commission may reject and require refiling of any substantially inadequate plan submitted under this division. After reasonable notice and opportunity for hearing, the commission shall approve the plan upon a finding that the plan will result in the utility's compliance with the order, this division, and any rules adopted under division (A) of section 4928.06 of the Revised Code. The approved independent transmission plan shall be deemed a part of the utility's transition plan for purposes of sections 4928.31 to 4928.40 of the Revised Code.

Cite as R.C. § 4928.35

Effective Date: 10-05-1999; 2008 SB221 07-31-2008

4928.36 Complaint concerning transition plan.

The public utilities commission has jurisdiction under section 4905.26 of the Revised Code, upon complaint by any person or upon complaint or initiative of the commission on or after the starting date of competitive retail electric service, to determine whether an electric utility has failed to implement, in conformance with an order under section 4928.33 of the Revised Code or in ongoing compliance with applicable provisions of the policy specified in section 4928.02 of the Revised Code, a transition plan approved under section 4928.33 of the Revised Code. If, after reasonable notice and opportunity for hearing as provided in section 4905.26 of the Revised Code, the commission determines that the utility has failed to so comply, the commission, in addition to any other remedies provided by law, may use the remedies specified in divisions (C)(1) to (3) and (D)(1) and (2) of section 4928.18 of the Revised Code to enforce compliance.

Cite as R.C. § 4928.36

Effective Date: 10-05-1999

4928.37 Receiving transition revenues.

(A)

(1) Sections 4928.31 to 4928.40 of the Revised Code provide an electric utility the opportunity to receive transition revenues that may assist it in making the transition to a fully competitive retail electric generation market. An electric utility for which transition revenues are approved pursuant to sections 4928.31 to 4928.40 of the Revised Code shall receive those revenues through both of the following mechanisms beginning on the starting date of competitive retail electric service and ending on the expiration date of its market development period as determined under section 4928.40 of the Revised Code:

(a) Payment of unbundled rates for retail electric services by each customer that is supplied retail electric generation service during the market development period by the customer's electric distribution utility, which rates shall be specified in schedules filed under section 4928.35 of the Revised Code;

(b) Payment of a nonbypassable and competitively neutral transition charge by each customer that is supplied retail electric generation service during the market development period by an entity other than the customer's electric distribution utility, as such transition charge is determined under section 4928.40 of the Revised Code. The transition charge shall be payable by each such retail electric distribution service customer in the certified territory of the electric utility for which the transition revenues are approved and shall be billed on each kilowatt hour of electricity delivered to the customer by the electric distribution utility as registered on the customer's meter during the utility's market development period as kilowatt hour is defined in section 4909.161 of the Revised Code or, if no meter is used, as based on an estimate of kilowatt hours used or consumed by the customer. The transition charge for each customer class shall reflect the cost allocation to that class as provided under bundled rates and charges in effect on the day before the effective date of this section. Additionally, as reflected in section 4928.40 of the Revised Code, the transition charges shall be structured to provide shopping incentives to customers sufficient to encourage the development of effective competition in the supply of retail electric generation service. To the extent possible, the level and structure of the transition charge shall be designed to avoid revenue responsibility shifts among the utility's customer classes and rate schedules.

(2)

(a) Notwithstanding division (A)(1)(b) of this section, the transition charge shall not be payable on electricity supplied by a municipal electric utility to a retail electric distribution service customer in the certified territory of the electric utility for which the transition revenues are approved, if the municipal electric utility provides electric transmission or distribution service, or both services, through transmission or distribution facilities singly or jointly owned or operated by the municipal electric utility, and if the municipal electric utility was in existence, operating, and providing service as of January 1, 1999.

(b) The transition charge shall not be payable on electricity supplied or consumed in this state except such electricity as is delivered to a retail customer by an electric distribution utility and is registered on the customer's meter during the utility's market development period or, if no meter is used, is based on an estimate of kilowatt hours used or consumed by the customer. However, no transition charge shall be payable on electricity that is both produced and consumed in this state by a self-generator.

(3) The transition charge shall not be discounted by any party.

(4) Nothing prevents payment of all or part of the transition charge by another party on a customer's behalf if that payment does not contravene sections 4905.33 to 4905.35 of the Revised Code or this

chapter.

(B) The electric utility shall separately itemize and disclose, or cause its billing and collection agent to separately itemize and disclose, the transition charge on the customer's bill in accordance with reasonable specifications the commission shall prescribe by rule under division (A) of section 4928.06 of the Revised Code.

Cite as R.C. § 4928.37

Effective Date: 10-05-1999

4928.38 Commencing and terminating transition revenues.

Pursuant to a transition plan approved under section 4928.33 of the Revised Code, an electric utility in this state may receive transition revenues under sections 4928.31 to 4928.40 of the Revised Code, beginning on the starting date of competitive retail electric service. Except as provided in sections 4905.33 to 4905.35 of the Revised Code and this chapter, an electric utility that receives such transition revenues shall be wholly responsible for how to use those revenues and wholly responsible for whether it is in a competitive position after the market development period. The utility's receipt of transition revenues shall terminate at the end of the market development period. With the termination of that approved revenue source, the utility shall be fully on its own in the competitive market. The commission shall not authorize the receipt of transition revenues or any equivalent revenues by an electric utility except as expressly authorized in sections 4928.31 to 4928.40 of the Revised Code.

Cite as R.C. § 4928.38

Effective Date: 10-05-1999

4928.39 Determining total allowable transition costs.

Upon the filing of an application by an electric utility under section 4928.31 of the Revised Code for the opportunity to receive transition revenues under sections 4928.31 to 4928.40 of the Revised Code, the public utilities commission, by order under section 4928.33 of the Revised Code, shall determine the total allowable amount of the transition costs of the utility to be received as transition revenues under those sections. Such amount shall be the just and reasonable transition costs of the utility, which costs the commission finds meet all of the following criteria:

(A) The costs were prudently incurred.

(B) The costs are legitimate, net, verifiable, and directly assignable or allocable to retail electric generation service provided to electric consumers in this state.

(C) The costs are unrecoverable in a competitive market.

(D) The utility would otherwise be entitled an opportunity to recover the costs. Transition costs under this section shall include the costs of employee assistance under the employee assistance plan included in the utility's approved transition plan under section 4928.33 of the Revised Code, which costs exceed those costs contemplated in labor contracts in effect on the effective date of this section. Further, the commission's order under this section shall separately identify regulatory assets of the utility that are a part of the total allowable amount of transition costs determined under this section and separately identify that portion of a transition charge determined under section 4928.40 of the Revised Code that is allocable to those assets, which portion of a transition charge shall be subject to adjustment only prospectively and after December 31, 2004, unless the commission authorizes an adjustment prospectively with an earlier date for any customer class based upon an earlier termination of the utility's market development period pursuant to division (B)(2) of section 4928.40 of the Revised Code. The electric utility shall have the burden of demonstrating allowable transition costs as authorized under this section. The commission may impose reasonable commitments upon the utility's collection of the transition revenues to ensure that those revenues are used to eliminate the allowable transition costs of the utility during the market development period and are not available for use by the utility to achieve an undue competitive advantage, or to impose an undue disadvantage, in the provision by the utility of regulated or unregulated products or services.

Cite as R.C. § 4928.39

Effective Date: 10-05-1999

4928.40 Establishing transition charge for each customer class.

(A) Upon determining under section 4928.39 of the Revised Code the allowable transition costs of an electric utility authorized for collection as transition revenues under sections 4928.31 to 4928.40 of the Revised Code, the public utilities commission, by order under section 4928.33 of the Revised Code, shall establish the transition charge for each customer class of the electric utility and, to the extent possible, each rate schedule within each such customer class, with all such transition charges being collected as provided in division (A)(1)(b) of section 4928.37 of the Revised Code during a market development period for the utility, ending on such date as the commission shall reasonably prescribe. The market development period shall end on December 31, 2005, unless otherwise authorized under division (B)(2) of this section. However, the commission may set the utility's recovery of the revenue requirements associated with regulatory assets, as established pursuant to section 4928.39 of the Revised Code, to end not later than December 31, 2010. The commission shall not permit the creation or amortization of additional regulatory assets without notice and an opportunity to be heard through an evidentiary hearing and shall not increase the charge recovering such revenue requirements associated with regulatory assets. Factors the commission shall consider in prescribing the expiration date of the utility's market development period and the transition charge for each customer class and rate schedule of the utility include, but are not limited to, the total allowable amount of transition costs of the electric utility as determined under section 4928.39 of the Revised Code; the relevant market price for the delivered supply of electricity to customers in that customer class and, to the extent possible, in each rate schedule as determined by the commission; and such shopping incentives by customer class as are considered necessary to induce, at the minimum, a twenty per cent load switching rate by customer class halfway through the utility's market development period but not later than December 31, 2003. In no case shall the commission establish a shopping incentive in an amount exceeding the unbundled component for retail electric generation service set in the utility's approved transition plan under section 4928.33 of the Revised Code, and in no case shall the commission establish a transition charge in an amount less than zero.

(B)

(1) The commission may conduct a periodic review no more often than annually and, as it determines necessary, adjust the transition charges of the electric utility as initially established under division (A) of this section or subsequently adjusted under this division. Any such adjustment shall be in accordance with division (A) of this section and may reflect changes in the relevant market.

(2) For purposes of this chapter, the market development period shall not end earlier than December 31, 2005, unless, upon application by an electric utility, the commission issues an order authorizing such

earlier date for one or more customer classes as is specified in the order, upon a demonstration by the utility and a finding by the commission of either of the following:

(a) There is a twenty per cent switching rate of the utility's load by the customer class.

(b) Effective competition exists in the utility's certified territory.

(C) Notwithstanding any provision of this chapter, the commission shall issue an order under section 4928.33 of the Revised Code approving a transition plan for an electric utility that contains a rate reduction for residential customers of that utility, provided that the rate reduction shall not increase the rates or transition cost responsibility of any other customer class of the utility. The rate reduction shall be in effect only for such portion of the utility's market development period as the commission shall specify and shall be applied to the unbundled generation component for retail electric generation service as set in the utility's approved transition plan under section 4928.33 of the Revised Code subject to the price cap for residential customers required under division (A)(6) of section 4928.34 of the Revised Code. The amount of the rate reduction shall be five per cent of the amount of that unbundled generation component, but shall not unduly discourage market entry by alternative suppliers seeking to serve the residential market in this state. The commission, after reasonable notice and opportunity for hearing, may terminate the rate reduction by order upon a finding that the rate reduction is unduly discouraging market entry by such alternative suppliers. No such termination of the rate reduction shall take effect prior to the midpoint of the utility's market development period.

(D) Beginning on the starting date of competitive retail electric service, no electric utility in this state shall prohibit the resale of electric generation service or impose unreasonable or discriminatory conditions or limitations on the resale of electric generation service.

(E) Notwithstanding any provision of Title XLIX [49] of the Revised Code to the contrary, any customer that receives a noncompetitive retail electric service from an electric distribution utility shall be a retail electric distribution service customer, irrespective of the voltage level at which service is taken.

Cite as R.C. § 4928.40

Effective Date: 10-05-1999

4928.41 [Repealed].

Cite as R.C. § 4928.41

Effective Date: 2008 SB221 07-31-2008

4928.42 [Repealed].

Cite as R.C. § 4928.42

Effective Date: 2008 SB221 07-31-2008

4928.43 Assisting employees affected by electric industry restructuring.

(A) Each state agency that provides employment assistance and job training programs, including the bureau of employment services and the department of development, shall provide concentrated attention through those programs to assisting employees whose employment is affected by electric industry restructuring under this chapter.

(B) To the extent not prohibited by federal law or any law of this state and except as otherwise provided in a labor contract or other agreement, no unencumbered money in a pension fund for employees of electric utilities shall be used for any purpose other than to pay allowable pensions or early retirement buyouts for the employees.

Cite as R.C. § 4928.43

Effective Date: 10-05-1999

4928.431 [Repealed].

Cite as R.C. § 4928.431

Effective Date: 2008 SB221 07-31-2008

4928.44 [Repealed].

Cite as R.C. § 4928.44

Effective Date: 2008 SB221 07-31-2008

4928.51 Universal service fund.

(A) There is hereby established in the state treasury a universal service fund, into which shall be deposited all universal service revenues remitted to the director of development under this section, for the exclusive purposes of providing funding for the low-income customer assistance programs and for the consumer education program authorized under section 4928.56 of the Revised Code, and paying the administrative costs of the low-income customer assistance programs and the consumer education program. Interest on the fund shall be credited to the fund. Disbursements from the fund shall be made to any supplier that provides a competitive retail electric service or a noncompetitive retail electric service to a customer who is approved to receive assistance under a specified low-income customer assistance program and to any authorized provider of weatherization or energy efficiency service to a customer approved to receive such assistance under a specified low-income customer assistance program.

(B) Universal service revenues shall include all of the following:

(1) Revenues remitted to the director after collection by an electric distribution utility beginning July 1, 2000, attributable to the collection from customers of the universal service rider prescribed under section 4928.52 of the Revised Code;

(2) Revenues remitted to the director that have been collected by an electric distribution utility beginning July 1, 2000, as customer payments under the percentage of income payment plan program, including revenues remitted under division (C) of this section;

(3) Adequate revenues remitted to the director after collection by a municipal electric utility or electric cooperative in this state not earlier than July 1, 2000, upon the utility's or cooperative's decision to participate in the low-income customer assistance programs.

(C)

(1) Beginning July 1, 2000, an electric distribution utility shall transfer to the director the right to collect all arrearage payments of a customer for percentage of income payment plan program debt owed to the utility on the day before that date or retain the right to collect that debt but remit to the director all

program revenues received by the utility for that customer.

(2) A current or past percentage of income payment plan program customer is relieved of any payment obligation under the percentage of income payment program for any unpaid arrears accrued by the customer under the program as of the effective date of this section if the customer, as determined by the director, meets both of the following criteria:

(a) The customer as of that date has complied with customer payment responsibilities under the program.

(b) The customer is permanently and totally disabled as defined in section 5117.01 of the Revised Code or is sixty-five years of age or older as defined in that section.

(D) The public utilities commission shall complete an audit of each electric utility by July 1, 2000, for the purpose of establishing a baseline for the percentage of income payment plan program component of the low-income assistance programs.

Cite as R.C. § 4928.51

Effective Date: 10-05-1999

4928.52 Universal service rider.

(A) Beginning July 1, 2000, the universal service rider shall replace the percentage of income payment plan rider in existence on the effective date of this section and any amount in the rates of an electric utility for the funding of low-income customer energy efficiency programs. The universal service rider shall be a rider on retail electric distribution service rates as such rates are determined by the public utilities commission pursuant to this chapter. The universal service rider for the first five years after the starting date of competitive retail electric service shall be the sum of all of the following:

(1) The level of the percentage of income payment plan program rider in existence on the effective date of this section;

(2) An amount equal to the level of funding for low-income customer energy efficiency programs provided through electric utility rates in effect on the effective date of this section;

(3) Any additional amount necessary and sufficient to fund through the universal service rider the administrative costs of the low-income customer assistance programs and the consumer education program created in section 4928.56 of the Revised Code.

(B) If, during or after the five-year period specified in division (A) of this section, the director of development, after consultation with the public benefits advisory board created under section 4928.58 of the Revised Code, determines that revenues in the universal service fund and revenues from federal or other sources of funding for those programs, including general revenue fund appropriations for the Ohio energy credit program, will be insufficient to cover the administrative costs of the low-income customer assistance programs and the consumer education program and provide adequate funding for those programs, the director shall file a petition with the commission for an increase in the universal service rider. The commission, after reasonable notice and opportunity for hearing, may adjust the universal service rider by the minimum amount necessary to provide the additional revenues. The commission shall not decrease the universal service rider without the approval of the director, after consultation by the director with the advisory board.

(C) The universal service rider established under division (A) or (B) of this section shall be set in such a manner so as not to shift among the customer classes of electric distribution utilities the costs of funding low-income customer assistance programs.

Cite as R.C. § 4928.52

Effective Date: 10-05-1999

4928.53 [Effective Until 9/12/2014] Director of development to administer low-income customer assistance programs.

(A) Beginning July 1, 2000, the director of development is hereby authorized to administer the low-income customer assistance programs. For that purpose, the public utilities commission shall cooperate with and provide such assistance as the director requires for administration of the low-income customer assistance programs. The director shall consolidate the administration of and redesign and coordinate the operations of those programs within the department to provide, to the maximum extent possible, for efficient program administration and a one-stop application and eligibility determination process at the local level for consumers.

(B)

(1) Not later than March 1, 2000, the director, in accordance with Chapter 119. of the Revised Code, shall adopt rules to carry out sections 4928.51 to 4928.58 of the Revised Code and ensure the effective and efficient administration and operation of the low-income customer assistance programs. The rules shall take effect on the July 1, 2000.

(2) The director's authority to adopt rules under this division for the Ohio energy credit program shall be subject to such rule-making authority as is conferred on the director by sections 5117.01 to 5117.12 of the Revised Code, as amended by Sub. S.B. No. 3 of the 123rd general assembly, except that rules initially adopted by the director for the Ohio energy credit program shall incorporate the substance of those sections as they exist on the effective date of this section.

(3) The director's authority to adopt rules under this division for the percentage of income payment plan program shall include authority to adopt rules prescribing criteria for customer eligibility and policies regarding payment and crediting arrangements and responsibilities, procedures for verifying customer eligibility, procedures for disbursing public funds to suppliers and otherwise administering funds under the director's jurisdiction, and requirements as to timely remittances of revenues described in division (B) of section 4928.51 of the Revised Code. The director's authority in division (B)(3) of this section excludes authority to prescribe service disconnection and customer billing policies and procedures and to address complaints against suppliers under the percentage of payment plan program, which excluded authority shall be exercised by the public utilities commission, in coordination with the director. Rules adopted by the director under this division for the percentage of income payment plan program shall specify a level of payment responsibility to be borne by an eligible customer based on a percentage of the customer's income. Rules initially adopted by the director for the percentage of income payment plan program shall incorporate the eligibility criteria and payment arrangement and responsibility policies set forth in rule 4901:1-18-04(B) of the Ohio Administrative Code in effect on the effective date of this section.

Cite as R.C. § 4928.53

Effective Date: 10-05-1999

4928.53 [Effective 9/12/2014] Director of development to administer low-income

customer assistance programs.

(A) Beginning July 1, 2000, the director of development is hereby authorized to administer the low-income customer assistance programs. For that purpose, the public utilities commission shall cooperate with and provide such assistance as the director requires for administration of the low-income customer assistance programs. The director shall consolidate the administration of and redesign and coordinate the operations of those programs within the department to provide, to the maximum extent possible, for efficient program administration and a one-stop application and eligibility determination process at the local level for consumers.

(B)

(1) Not later than March 1, 2000, the director, in accordance with Chapter 119. of the Revised Code, shall adopt rules to carry out sections 4928.51 to 4928.58 of the Revised Code and ensure the effective and efficient administration and operation of the low-income customer assistance programs. The rules shall take effect on July 1, 2000.

(2) The director's authority to adopt rules under this division for the Ohio energy credit program shall be subject to such rule-making authority as is conferred on the director by sections 5117.01 to 5117.12 of the Revised Code, as amended by Sub. S.B. No. 3 of the 123rd general assembly, except that rules initially adopted by the director for the Ohio energy credit program shall incorporate the substance of those sections as they exist on the effective date of this section.

(3) The director's authority to adopt rules under this division for the percentage of income payment plan program shall include authority to adopt rules prescribing criteria for customer eligibility and policies regarding payment and crediting arrangements and responsibilities, procedures for verifying customer eligibility, procedures for disbursing public funds to suppliers and otherwise administering funds under the director's jurisdiction, and requirements as to timely remittances of revenues described in division (B) of section 4928.51 of the Revised Code. The rules shall prohibit the imposition of a waiting period before enrolling an eligible customer in the percentage of income payment plan. The director's authority in division (B)(3) of this section excludes authority to prescribe service disconnection and customer billing policies and procedures and to address complaints against suppliers under the percentage of payment plan program, which excluded authority shall be exercised by the public utilities commission, in coordination with the director. Rules adopted by the director under this division for the percentage of income payment plan program shall specify a level of payment responsibility to be borne by an eligible customer based on a percentage of the customer's income. Rules initially adopted by the director for the percentage of income payment plan program shall incorporate the eligibility criteria and payment arrangement and responsibility policies set forth in rule 4901:1-18-04(B) of the Ohio Administrative Code in effect on the effective date of this section.

Cite as R.C. § 4928.53

Amended by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

Effective Date: 10-05-1999

4928.54 Aggregate percentage of income payment plan program customers.

Beginning on the starting date of competitive retail electric service, the director of development may aggregate percentage of income payment plan program customers for the purpose of competitively auctioning the supply of competitive retail electric generation service to bidders certified under section

4928.08 of the Revised Code and further qualified under eligibility criteria the director prescribes by rule under division (B) of section 4928.53 of the Revised Code after consultation with the commission and electric light companies regarding any such rule. The objectives of the auction shall be to provide reliable retail electric generation service to customers, based on selection criteria that the winning bid provide the lowest cost and best value to customers. The rules adopted by the director under division (B) of section 4928.53 of the Revised Code shall ensure a fair and unbiased auction process and the performance of any winning bidder.

Cite as R.C. § 4928.54

Effective Date: 10-05-1999

4928.55 Energy efficiency and weatherization program.

The director of development shall establish an energy efficiency and weatherization program targeted, to the extent practicable, to high-cost, high-volume use structures occupied by customers eligible for the percentage of income payment plan program, with the goal of reducing the energy bills of the occupants. Acceptance of energy efficiency and weatherization services provided by the program shall be a condition for the eligibility of any such customer to participate in the percentage of income payment plan program. Any difference between universal service fund revenues under section 4928.51 of the Revised Code and any savings in percentage of income payment plan program costs as a result of competitive auctioning under section 4928.54 of the Revised Code shall be reinvested in the targeted energy efficiency and weatherization program.

Cite as R.C. § 4928.55

Effective Date: 10-05-1999

4928.56 Education program for consumers eligible to participate in low-income customer assistance programs.

The director of development may adopt rules in accordance with Chapter 119. of the Revised Code establishing an education program for consumers eligible to participate in the low-income customer assistance programs. The education program shall provide information to consumers regarding energy efficiency and energy conservation.

Cite as R.C. § 4928.56

Effective Date: 10-05-1999

4928.57 Biennial report to general assembly.

On and after the starting date of competitive retail electric service, the director of development shall provide a report every two years until 2008 to the standing committees of the general assembly that deal with public utility matters, regarding the effectiveness of the low-income customer assistance programs and the consumer education program, and the effectiveness of the advanced energy program created under sections 4928.61 to 4928.63 of the Revised Code.

Cite as R.C. § 4928.57

Effective Date: 10-05-1999; 01-04-2007

4928.58 Public benefits advisory board.

(A) There is hereby created the public benefits advisory board, which has the purpose of ensuring that energy services be provided to low-income consumers in this state in an affordable manner consistent with the policy specified in section 4928.02 of the Revised Code. The advisory board shall consist of twenty-one members as follows: the director of development, the chairperson of the public utilities commission, the consumers' counsel, and the director of the air quality development authority, each serving ex officio and represented by a designee at the official's discretion; two members of the house of representatives appointed by the speaker of the house of representatives, neither of the same political party, and two members of the senate appointed by the president of the senate, neither of the same political party; and thirteen members appointed by the governor with the advice and consent of the senate, consisting of one representative of suppliers of competitive retail electric service; one representative of the residential class of electric utility customers; one representative of the industrial class of electric utility customers; one representative of the commercial class of electric utility customers; one representative of agricultural or rural customers of an electric utility; two customers receiving assistance under one or more of the low-income customer assistance programs, to represent customers eligible for any such assistance, including senior citizens; one representative of the general public; one representative of local intake agencies; one representative of a community-based organization serving low-income customers; one representative of environmental protection interests; one representative of lending institutions; and one person considered an expert in energy efficiency or renewables technology. Initial appointments shall be made not later than November 1, 1999.

(B) Initial terms of six of the appointed members shall end on June 30, 2003, and initial terms of the remaining seven appointed members shall end on June 30, 2004. Thereafter, terms of appointed members shall be for three years, with each term ending on the same day of the same month as the term it succeeds. Each member shall hold office from the date of the member's appointment until the end of the term for which the member was appointed. Members may be reappointed. Vacancies shall be filled in the manner provided for original appointments. Any member appointed to fill a vacancy occurring prior to the expiration date of the term for which the member's predecessor was appointed shall hold office as a member for the remainder of that term. A member shall continue in office after the expiration date of the member's term until the member's successor takes office or until a period of sixty days has elapsed, whichever occurs first.

(C) Board members shall be reimbursed for their actual and necessary expenses incurred in the performance of board duties. The reimbursements constitute, as applicable, administrative costs of the low-income customer assistance programs for the purpose of division (A) of section 4928.51 of the Revised Code or administrative costs of the advanced energy program for the purpose of division (A) of section 4528.61 of the Revised Code.

(D) The advisory board shall select a chairperson from among its members. Only board members appointed by the governor with the advice and consent of the senate shall be voting members of the board; each shall have one vote in all deliberations of the board. A majority of the voting members constitute a quorum.

(E) The duties of the advisory board shall be as follows:

(1) Advise the director in the administration of the universal service fund and the low-income customer assistance programs and advise the director on the director's recommendation to the commission regarding the appropriate level of the universal service rider;

(2) Advise the director on the administration of the advanced energy program and the advanced energy fund under sections 4928.61 to 4928.63 of the Revised Code.

(F) The advisory board is not an agency for purposes of sections 101.82 to 101.87 of the Revised Code.

Cite as R.C. § 4928.58

Effective Date: 03-22-2001; 01-04-2007

4928.61 Energy efficiency revolving loan fund.

(A) There is hereby established in the state treasury the advanced energy fund, into which shall be deposited all advanced energy revenues remitted to the director of development under division (B) of this section, for the exclusive purposes of funding the advanced energy program created under section 4928.62 of the Revised Code and paying the program's administrative costs. Interest on the fund shall be credited to the fund.

(B) Advanced energy revenues shall include all of the following:

(1) Revenues remitted to the director after collection by each electric distribution utility in this state of a temporary rider on retail electric distribution service rates as such rates are determined by the public utilities commission pursuant to this chapter. The rider shall be a uniform amount statewide, determined by the director of development, after consultation with the public benefits advisory board created by section 4928.58 of the Revised Code. The amount shall be determined by dividing an aggregate revenue target for a given year as determined by the director, after consultation with the advisory board, by the number of customers of electric distribution utilities in this state in the prior year. Such aggregate revenue target shall not exceed more than fifteen million dollars in any year through 2005 and shall not exceed more than five million dollars in any year after 2005. The rider shall be imposed beginning on the effective date of the amendment of this section by Sub. H.B. 251 of the 126th general assembly, January 4, 2007, and shall terminate at the end of ten years following the starting date of competitive retail electric service or until the advanced energy fund, including interest, reaches one hundred million dollars, whichever is first.

(2) Revenues from payments, repayments, and collections under the advanced energy program and from program income;

(3) Revenues remitted to the director after collection by a municipal electric utility or electric cooperative in this state upon the utility's or cooperative's decision to participate in the advanced energy fund;

(4) Revenues from renewable energy compliance payments as provided under division (C)(2) of section 4928.64 of the Revised Code;

(5) Revenue from forfeitures under division (C) of section 4928.66 of the Revised Code;

(6) Funds transferred pursuant to division (B) of Section 512.10 of S.B. 315 of the 129th general assembly;

(7) Interest earnings on the advanced energy fund.

(C)

(1) Each electric distribution utility in this state shall remit to the director on a quarterly basis the revenues described in divisions (B)(1) and (2) of this section. Such remittances shall occur within thirty

days after the end of each calendar quarter.

(2) Each participating electric cooperative and participating municipal electric utility shall remit to the director on a quarterly basis the revenues described in division (B)(3) of this section. Such remittances shall occur within thirty days after the end of each calendar quarter. For the purpose of division (B)(3) of this section, the participation of an electric cooperative or municipal electric utility in the energy efficiency revolving loan program as it existed immediately prior to the effective date of the amendment of this section by Sub. H.B. 251 of the 126th general assembly, January 4, 2007, does not constitute a decision to participate in the advanced energy fund under this section as so amended.

(3) All remittances under divisions (C)(1) and (2) of this section shall continue only until the end of ten years following the starting date of competitive retail electric service or until the advanced energy fund, including interest, reaches one hundred million dollars, whichever is first.

(D) Any moneys collected in rates for non-low-income customer energy efficiency programs, as of October 5, 1999, and not contributed to the energy efficiency revolving loan fund authorized under this section prior to the effective date of its amendment by Sub. H.B. 251 of the 126th general assembly, January 4, 2007, shall be used to continue to fund cost-effective, residential energy efficiency programs, be contributed into the universal service fund as a supplement to that required under section 4928.53 of the Revised Code, or be returned to ratepayers in the form of a rate reduction at the option of the affected electric distribution utility.

Cite as R.C. § 4928.61

Amended by 129th General AssemblyFile No.125, SB 315, §101.01, eff. 9/10/2012.

Effective Date: 10-05-1999; 01-04-2007; 2008 SB221 07-31-2008

4928.62 Energy efficiency revolving loan program.

(A) There is hereby created the advanced energy program, which shall be administered by the director of development. Under the program, the director may authorize the use of moneys in the advanced energy fund for financial, technical, and related assistance for advanced energy projects in this state or for economic development assistance, in furtherance of the purposes set forth in section 4928.63 of the Revised Code.

(1) To the extent feasible given approved applications for assistance, the assistance shall be distributed among the certified territories of electric distribution utilities and participating electric cooperatives, and among the service areas of participating municipal electric utilities, in amounts proportionate to the remittances of each utility and cooperative under divisions (B)(1) and (3) of section 4928.61 of the Revised Code.

(2) The funds described in division (B)(6) of section 4928.61 of the Revised Code shall not be subject to the territorial requirements of division (A)(1) of this section.

(3) The director shall not authorize financial assistance for an advanced energy project under the program unless the director first determines that the project will create new jobs or preserve existing jobs in this state or use innovative technologies or materials.

(B) In carrying out sections 4928.61 to 4928.63 of the Revised Code, the director may do all of the following to further the public interest in advanced energy projects and economic development:

(1) Award grants, contracts, loans, loan participation agreements, linked deposits, and energy production incentives;

(2) Acquire in the name of the director any property of any kind or character in accordance with this section, by purchase, purchase at foreclosure, or exchange, on such terms and in such manner as the director considers proper;

(3) Make and enter into all contracts and agreements necessary or incidental to the performance of the director's duties and the exercise of the director's powers under sections 4928.61 to 4928.63 of the Revised Code;

(4) Employ or enter into contracts with financial consultants, marketing consultants, consulting engineers, architects, managers, construction experts, attorneys, technical monitors, energy evaluators, or other employees or agents as the director considers necessary, and fix their compensation;

(5) Adopt rules prescribing the application procedures for financial assistance under the advanced energy program; the fees, charges, interest rates, payment schedules, local match requirements, and other terms and conditions of any grants, contracts, loans, loan participation agreements, linked deposits, and energy production incentives; criteria pertaining to the eligibility of participating lending institutions; and any other matters necessary for the implementation of the program;

(6) Do all things necessary and appropriate for the operation of the program.

(C) The department of development may hold ownership to any unclaimed energy efficiency and renewable energy emission allowances provided for in Chapter 3745-14 of the Administrative Code or otherwise, that result from advanced energy projects that receive funding from the advanced energy fund, and it may use the allowances to further the public interest in advanced energy projects or for economic development.

(D) Financial statements, financial data, and trade secrets submitted to or received by the director from an applicant or recipient of financial assistance under sections 4928.61 to 4928.63 of the Revised Code, or any information taken from those statements, data, or trade secrets for any purpose, are not public records for the purpose of section 149.43 of the Revised Code.

(E) Nothing in the amendments of sections 4928.61 , 4928.62, and 4928.63 of the Revised Code by Sub. H.B. 251 of the 126th general assembly shall affect any pending or effected assistance, pending or effected purchases or exchanges of property made, or pending or effected contracts or agreements entered into pursuant to division (A) or (B) of this section as the section existed prior to the effective date of those amendments, January 4, 2007, or shall affect the exemption provided under division (C) of this section as the section existed prior to that effective date.

(F) Any assistance a school district receives for an advanced energy project, including a geothermal heating, ventilating, and air conditioning system, shall be in addition to any assistance provided under Chapter 3318. of the Revised Code and shall not be included as part of the district or state portion of the basic project cost under that chapter.

Cite as R.C. § 4928.62

Amended by 129th General AssemblyFile No.125, SB 315, §101.01, eff. 9/10/2012.

Effective Date: 04-07-2004; 01-04-2007

4928.621 Creating an advanced energy manufacturing center.

(A) Any Edison technology center in this state is eligible to apply for and receive assistance pursuant to section 4928.62 of the Revised Code for the purposes of creating an advanced energy manufacturing center in this state that will provide for the exchange of information and expertise regarding advanced energy, assisting with the design of advanced energy projects, developing workforce training programs for such projects, and encouraging investment in advanced energy manufacturing technologies for advanced energy products and investment in sustainable manufacturing operations that create high-paying jobs in this state.

(B) Any university or group of universities in this state that conducts research on any advanced energy resource or any not-for-profit corporation formed to address issues affecting the price and availability of electricity and having members that are small businesses may apply for and receive assistance pursuant to section 4928.62 of the Revised Code for the purpose of encouraging research in this state that is directed at innovation in or the refinement of those resources or for the purpose of educational outreach regarding those resources and, to that end, shall use that assistance to establish such a program of research or education outreach. Any such educational outreach shall be directed at an increase in, innovation regarding, or refinement of access by or of application or understanding of businesses and consumers in this state regarding, advanced energy resources.

(C) Any independent group located in this state the express objective of which is to educate small businesses in this state regarding renewable energy resources and energy efficiency programs, or any small business located in this state electing to utilize an advanced energy project or participate in an energy efficiency program, is eligible to apply for and receive assistance pursuant to section 4928.62 of the Revised Code.

(D) Nothing in this section shall be construed as limiting the eligibility of any qualifying entity to apply for or receive assistance pursuant to section 4928.62 of the Revised Code.

Cite as R.C. § 4928.621

Effective Date: 2008 SB221 07-31-2008

4928.63 Purpose of energy efficiency program.

The director of development and the public benefits advisory board have the powers and duties provided in sections 4928.61 and 4928.62 of the Revised Code, in order to promote the welfare of the people of this state; stabilize the economy; assist in the improvement and development within this state of not-for-profit entity, industrial, commercial, distribution, residential, and research buildings and activities required for the people of this state; improve the economic welfare of the people of this state by reducing energy costs and by reducing energy usage in a cost-efficient manner using, as determined by the director, both the most appropriate national, federal, or other standards for products and the best practices for the use of technology, products, or services in the context of a total facility or building; and assist in the lowering of energy demand to reduce air, water, or thermal pollution . It is hereby determined that the accomplishment of those purposes is essential so that the people of this state may maintain their present high standards in comparison with the people of other states and so that opportunities for improving the economic welfare of the people of this state, for improving the housing of residents of this state, and for favorable markets for the products of this state's natural resources, agriculture, and manufacturing shall be improved; and that it is necessary for this state to establish the program authorized pursuant to sections 4928.61 and 4928.62 of the Revised Code.

Cite as R.C. § 4928.63

Effective Date: 04-07-2004; 01-04-2007

4928.64 [Effective Until 9/12/2014] Electric distribution utility to provide electricity from alternative energy resources.

(A)

(1) As used in sections 4928.64 and 4928.65 of the Revised Code, "alternative energy resource" means an advanced energy resource or renewable energy resource, as defined in section 4928.01 of the Revised Code that has a placed-in-service date of January 1, 1998, or after; a renewable energy resource created on or after January 1, 1998, by the modification or retrofit of any facility placed in service prior to January 1, 1998; or a mercantile customer-sited advanced energy resource or renewable energy resource, whether new or existing, that the mercantile customer commits for integration into the electric distribution utility's demand-response, energy efficiency, or peak demand reduction programs as provided under division (A)(2)(c) of section 4928.66 of the Revised Code, including, but not limited to, any of the following:

(a) A resource that has the effect of improving the relationship between real and reactive power;

(b) A resource that makes efficient use of waste heat or other thermal capabilities owned or controlled by a mercantile customer;

(c) Storage technology that allows a mercantile customer more flexibility to modify its demand or load and usage characteristics;

(d) Electric generation equipment owned or controlled by a mercantile customer that uses an advanced energy resource or renewable energy resource;

(e) Any advanced energy resource or renewable energy resource of the mercantile customer that can be utilized effectively as part of any advanced energy resource plan of an electric distribution utility and would otherwise qualify as an alternative energy resource if it were utilized directly by an electric distribution utility.

(2) For the purpose of this section and as it considers appropriate, the public utilities commission may classify any new technology as such an advanced energy resource or a renewable energy resource.

(B) By 2025 and thereafter, an electric distribution utility shall provide from alternative energy resources, including, at its discretion, alternative energy resources obtained pursuant to an electricity supply contract, a portion of the electricity supply required for its standard service offer under section 4928.141 of the Revised Code, and an electric services company shall provide a portion of its electricity supply for retail consumers in this state from alternative energy resources, including, at its discretion, alternative energy resources obtained pursuant to an electricity supply contract. That portion shall equal twenty-five per cent of the total number of kilowatt hours of electricity sold by the subject utility or company to any and all retail electric consumers whose electric load centers are served by that utility and are located within the utility's certified territory or, in the case of an electric services company, are served by the company and are located within this state. However, nothing in this section precludes a utility or company from providing a greater percentage. The baseline for a utility's or company's compliance with the alternative energy resource requirements of this section shall be the average of such total kilowatt hours it sold in the preceding three calendar years, except that the commission may reduce a utility's or company's baseline to adjust for new economic growth in the utility's certified territory or, in the case of an electric services company, in the company's service area in this state.

Of the alternative energy resources implemented by the subject utility or company by 2025 and thereafter:

(1) Half may be generated from advanced energy resources;

(2) At least half shall be generated from renewable energy resources, including one-half per cent from solar energy resources, in accordance with the following benchmarks:

By end of year	Renewable energy resources	Solar energy resources
2009	0.25%	0.004%
2010	0.50%	0.010%
2011	1%	0.030%
2012	1.5%	0.060%
2013	2%	0.090%
2014	2.5%	0.12%
2015	3.5%	0.15%
2016	4.5%	0.18%
2017	5.5%	0.22%
2018	6.5%	0.26%
2019	7.5%	0.3%
2020	8.5%	0.34%
2021	9.5%	0.38%
2022	10.5%	0.42%
2023	11.5%	0.46%
2024 and each calendar year thereafter	12.5%	0.5%

(3) At least one-half of the renewable energy resources implemented by the utility or company shall be met through facilities located in this state; the remainder shall be met with resources that can be shown to be deliverable into this state.

(C)

(1) The commission annually shall review an electric distribution utility's or electric services company's compliance with the most recent applicable benchmark under division (B)(2) of this section and, in the course of that review, shall identify any undercompliance or noncompliance of the utility or company that it determines is weather-related, related to equipment or resource shortages for advanced energy or renewable energy resources as applicable, or is otherwise outside the utility's or company's control.

(2) Subject to the cost cap provisions of division (C)(3) of this section, if the commission determines, after notice and opportunity for hearing, and based upon its findings in that review regarding avoidable undercompliance or noncompliance, but subject to division (C)(4) of this section, that the utility or company has failed to comply with any such benchmark, the commission shall impose a renewable energy compliance payment on the utility or company.

(a) The compliance payment pertaining to the solar energy resource benchmarks under division (B)(2) of this section shall be an amount per megawatt hour of undercompliance or noncompliance in the period under review, starting at four hundred fifty dollars for 2009, four hundred dollars for 2010 and 2011, and similarly reduced every two years thereafter through 2024 by fifty dollars, to a minimum of fifty dollars.

(b) The compliance payment pertaining to the renewable energy resource benchmarks under division (B)(2) of this section shall equal the number of additional renewable energy credits that the electric distribution utility or electric services company would have needed to comply with the applicable benchmark in the period under review times an amount that shall begin at forty-five dollars and shall be adjusted annually by the commission to reflect any change in the consumer price index as defined in section 101.27 of the Revised Code, but shall not be less than forty-five dollars.

(c) The compliance payment shall not be passed through by the electric distribution utility or electric services company to consumers. The compliance payment shall be remitted to the commission, for deposit to the credit of the advanced energy fund created under section 4928.61 of the Revised Code. Payment of the compliance payment shall be subject to such collection and enforcement procedures as apply to the collection of a forfeiture under sections 4905.55 to 4905.60 and 4905.64 of the Revised Code.

(3) An electric distribution utility or an electric services company need not comply with a benchmark under division (B)(1) or (2) of this section to the extent that its reasonably expected cost of that compliance exceeds its reasonably expected cost of otherwise producing or acquiring the requisite electricity by three per cent or more. The cost of compliance shall be calculated as though any exemption from taxes and assessments had not been granted under section 5727.75 of the Revised Code.

(4)

(a) An electric distribution utility or electric services company may request the commission to make a force majeure determination pursuant to this division regarding all or part of the utility's or company's compliance with any minimum benchmark under division (B)(2) of this section during the period of review occurring pursuant to division (C)(2) of this section. The commission may require the electric distribution utility or electric services company to make solicitations for renewable energy resource credits as part of its default service before the utility's or company's request of force majeure under this division can be made.

(b) Within ninety days after the filing of a request by an electric distribution utility or electric services company under division (C)(4)(a) of this section, the commission shall determine if renewable energy resources are reasonably available in the marketplace in sufficient quantities for the utility or company to comply with the subject minimum benchmark during the review period. In making this determination, the commission shall consider whether the electric distribution utility or electric services company has made a good faith effort to acquire sufficient renewable energy or, as applicable, solar energy resources to so comply, including, but not limited to, by banking or seeking renewable energy resource credits or by seeking the resources through long-term contracts. Additionally, the commission shall consider the availability of renewable energy or solar energy resources in this state and other jurisdictions in the PJM interconnection regional transmission organization or its successor and the midwest system operator or its successor.

(c) If, pursuant to division (C)(4)(b) of this section, the commission determines that renewable energy or solar energy resources are not reasonably available to permit the electric distribution utility or electric services company to comply, during the period of review, with the subject minimum benchmark prescribed under division (B)(2) of this section, the commission shall modify that compliance obligation of the utility or company as it determines appropriate to accommodate the finding. Commission modification shall not automatically reduce the obligation for the electric distribution utility's or electric services company's compliance in subsequent years. If it modifies the electric distribution utility or electric services company obligation under division (C)(4)(c) of this section, the commission may require the utility or company, if sufficient renewable energy resource credits exist in the marketplace, to acquire additional renewable energy resource credits in subsequent years equivalent to the utility's or company's modified obligation under division (C)(4)(c) of this section.

(5) The commission shall establish a process to provide for at least an annual review of the alternative energy resource market in this state and in the service territories of the regional transmission organizations that manage transmission systems located in this state. The commission shall use the results of this study to identify any needed changes to the amount of the renewable energy compliance payment specified under divisions (C)(2)(a) and (b) of this section. Specifically, the commission may increase the amount to ensure that payment of compliance payments is not used to achieve compliance with this section in lieu of actually acquiring or realizing energy derived from renewable energy resources. However, if the commission finds that the amount of the compliance payment should be otherwise changed, the commission shall present this finding to the general assembly for legislative enactment.

(D)

(1) The commission annually shall submit to the general assembly in accordance with section 101.68 of the Revised Code a report describing all of the following:

(a) The compliance of electric distribution utilities and electric services companies with division (B) of this section ;

(b) The average annual cost of renewable energy credits purchased by utilities and companies for the year covered in the report;

(c) Any strategy for utility and company compliance or for encouraging the use of alternative energy resources in supplying this state's electricity needs in a manner that considers available technology, costs, job creation, and economic impacts.

The commission shall begin providing the information described in division (D)(1)(b) of this section in each report submitted after the effective date of the amendment of this section by S.B. 315 of the 129th general assembly. The commission shall allow and consider public comments on the report prior to its submission to the general assembly. Nothing in the report shall be binding on any person, including any utility or company for the purpose of its compliance with any benchmark under division (B) of this section, or the enforcement of that provision under division (C) of this section.

(2) The governor, in consultation with the commission chairperson, shall appoint an alternative energy advisory committee. The committee shall examine available technology for and related timetables, goals, and costs of the alternative energy resource requirements under division (B) of this section and shall submit to the commission a semiannual report of its recommendations.

(E) All costs incurred by an electric distribution utility in complying with the requirements of this section shall be bypassable by any consumer that has exercised choice of supplier under section 4928.03 of the Revised Code.

Cite as R.C. § 4928.64

Amended by 129th General AssemblyFile No.125, SB 315, §101.01, eff. 9/10/2012.

Amended by 128th General AssemblyFile No.48, SB 232, §1, eff. 6/17/2010.

Amended by 128th General Assemblych.48, HB 2, §101.01, eff. 7/1/2009.

Effective Date: 2008 SB221 07-31-2008

4928.64 [Effective 9/12/2014] Electric distribution utility to provide electricity from alternative energy resources.

(A)

(1) As used in this section, " qualifying renewable energy resource" means a renewable energy resource, as defined in section 4928.01 of the Revised Code that has a placed-in-service date on or after January 1, 1998, or with respect to any run-of-the-river hydroelectric facility, an in-service date on or after January 1, 1980; a renewable energy resource created on or after January 1, 1998, by the modification or retrofit of any facility placed in service prior to January 1, 1998; or a mercantile customer-sited renewable energy resource, whether new or existing, that the mercantile customer commits for integration into the electric distribution utility's demand-response, energy efficiency, or peak demand reduction programs as provided under division (A)(2)(c) of section 4928.66 of the Revised Code, including, but not limited to, any of the following:

(a) A resource that has the effect of improving the relationship between real and reactive power;

(b) A resource that makes efficient use of waste heat or other thermal capabilities owned or controlled by a mercantile customer;

(c) Storage technology that allows a mercantile customer more flexibility to modify its demand or load and usage characteristics;

(d) Electric generation equipment owned or controlled by a mercantile customer that uses a renewable energy resource

.

(2) For the purpose of this section and as it considers appropriate, the public utilities commission may classify any new technology as such a qualifying renewable energy resource.

(B)

(1) By 2027 and thereafter, an electric distribution utility shall provide from qualifying renewable energy resources, including, at its discretion, qualifying renewable energy resources obtained pursuant to an electricity supply contract, a portion of the electricity supply required for its standard service offer under section 4928.141 of the Revised Code, and an electric services company shall provide a portion of its electricity supply for retail consumers in this state from qualifying renewable energy resources, including, at its discretion, qualifying renewable energy resources obtained pursuant to an electricity supply contract. That portion shall equal twelve and one-half per cent of the total number of kilowatt hours of electricity sold by the subject utility or company to any and all retail electric consumers whose electric load centers are served by that utility and are located within the utility's certified territory or, in the case of an electric services company, are served by the company and are located within this state. However, nothing in this section precludes a utility or company from providing a greater percentage.

(2) The portion required under division (B)(1) of this section shall be generated from renewable energy resources, including one-half per cent from solar energy resources, in accordance with the following benchmarks:

By end of year	Renewable energy resources	Solar energy resources
2009	0.25%	0.004%
2010	0.50%	0.010%
2011	1%	0.030%
2012	1.5%	0.060%
2013	2%	0.090%
2014	2.5%	0.12%
2015	2.5%	0.12%
2016	2.5%	0.12%
2017	3.5%	0.15%
2018	4.5%	0.18%
2019	5.5%	0.22%
2020	6.5%	0.26%
2021	7.5%	0.3%
2022	8.5%	0.34%
2023	9.5%	0.38%
2024	10.5%	0.42%

2025	11.5%	0.46%
2026 and each calendar year thereafter	12.5%	0.5%.

(3) The qualifying renewable energy resources implemented by the utility or company shall be met either:

(a) Through facilities located in this state; or

(b) With resources that can be shown to be deliverable into this state.

(C)

(1) The commission annually shall review an electric distribution utility's or electric services company's compliance with the most recent applicable benchmark under division (B)(2) of this section and, in the course of that review, shall identify any undercompliance or noncompliance of the utility or company that it determines is weather-related, related to equipment or resource shortages for qualifying renewable energy resources as applicable, or is otherwise outside the utility's or company's control.

(2) Subject to the cost cap provisions of division (C)(3) of this section, if the commission determines, after notice and opportunity for hearing, and based upon its findings in that review regarding avoidable undercompliance or noncompliance, but subject to division (C)(4) of this section, that the utility or company has failed to comply with any such benchmark, the commission shall impose a renewable energy compliance payment on the utility or company.

(a) The compliance payment pertaining to the solar energy resource benchmarks under division (B)(2) of this section shall be an amount per megawatt hour of undercompliance or noncompliance in the period under review, as follows:

(i) Three hundred dollars for 2014, 2015, and 2016;

(ii) Two hundred fifty dollars for 2017 and 2018;

(iii) Two hundred dollars for 2019 and 2020;

(iv) Similarly reduced every two years thereafter through 2026 by fifty dollars, to a minimum of fifty dollars.

(b) The compliance payment pertaining to the renewable energy resource benchmarks under division (B)(2) of this section shall equal the number of additional renewable energy credits that the electric distribution utility or electric services company would have needed to comply with the applicable benchmark in the period under review times an amount that shall begin at forty-five dollars and shall be adjusted annually by the commission to reflect any change in the consumer price index as defined in section 101.27 of the Revised Code, but shall not be less than forty-five dollars.

(c) The compliance payment shall not be passed through by the electric distribution utility or electric services company to consumers. The compliance payment shall be remitted to the commission, for deposit to the credit of the advanced energy fund created under section 4928.61 of the Revised Code. Payment of the compliance payment shall be subject to such collection and enforcement procedures as apply to the collection of a forfeiture under sections 4905.55 to 4905.60 and 4905.64 of the Revised Code.

(3) An electric distribution utility or an electric services company need not comply with a benchmark under

division (B) (2) of this section to the extent that its reasonably expected cost of that compliance exceeds its reasonably expected cost of otherwise producing or acquiring the requisite electricity by three per cent or more. The cost of compliance shall be calculated as though any exemption from taxes and assessments had not been granted under section 5727.75 of the Revised Code.

(4)

(a) An electric distribution utility or electric services company may request the commission to make a force majeure determination pursuant to this division regarding all or part of the utility's or company's compliance with any minimum benchmark under division (B)(2) of this section during the period of review occurring pursuant to division (C)(2) of this section. The commission may require the electric distribution utility or electric services company to make solicitations for renewable energy resource credits as part of its default service before the utility's or company's request of force majeure under this division can be made.

(b) Within ninety days after the filing of a request by an electric distribution utility or electric services company under division (C)(4)(a) of this section, the commission shall determine if qualifying renewable energy resources are reasonably available in the marketplace in sufficient quantities for the utility or company to comply with the subject minimum benchmark during the review period. In making this determination, the commission shall consider whether the electric distribution utility or electric services company has made a good faith effort to acquire sufficient qualifying renewable energy or, as applicable, solar energy resources to so comply, including, but not limited to, by banking or seeking renewable energy resource credits or by seeking the resources through long-term contracts. Additionally, the commission shall consider the availability of qualifying renewable energy or solar energy resources in this state and other jurisdictions in the PJM interconnection regional transmission organization, L.L.C., or its successor and the midcontinent independent system operator or its successor.

(c) If, pursuant to division (C)(4)(b) of this section, the commission determines that qualifying renewable energy or solar energy resources are not reasonably available to permit the electric distribution utility or electric services company to comply, during the period of review, with the subject minimum benchmark prescribed under division (B)(2) of this section, the commission shall modify that compliance obligation of the utility or company as it determines appropriate to accommodate the finding. Commission modification shall not automatically reduce the obligation for the electric distribution utility's or electric services company's compliance in subsequent years. If it modifies the electric distribution utility or electric services company obligation under division (C)(4)(c) of this section, the commission may require the utility or company, if sufficient renewable energy resource credits exist in the marketplace, to acquire additional renewable energy resource credits in subsequent years equivalent to the utility's or company's modified obligation under division (C)(4)(c) of this section.

(5) The commission shall establish a process to provide for at least an annual review of the renewable energy resource market in this state and in the service territories of the regional transmission organizations that manage transmission systems located in this state. The commission shall use the results of this study to identify any needed changes to the amount of the renewable energy compliance payment specified under divisions (C)(2)(a) and (b) of this section. Specifically, the commission may increase the amount to ensure that payment of compliance payments is not used to achieve compliance with this section in lieu of actually acquiring or realizing energy derived from qualifying renewable energy resources. However, if the commission finds that the amount of the compliance payment should be otherwise changed, the commission shall present this finding to the general assembly for legislative enactment.

(D) The commission annually shall submit to the general assembly in accordance with section 101.68 of the Revised Code a report describing all of the following:

(1) The compliance of electric distribution utilities and electric services companies with division (B) of this section;

(2) The average annual cost of renewable energy credits purchased by utilities and companies for the year covered in the report;

(3) Any strategy for utility and company compliance or for encouraging the use of qualifying renewable energy resources in supplying this state's electricity needs in a manner that considers available technology, costs, job creation, and economic impacts.

The commission shall begin providing the information described in division (D) (2) of this section in each report submitted after September 10, 2012. The commission shall allow and consider public comments on the report prior to its submission to the general assembly. Nothing in the report shall be binding on any person, including any utility or company for the purpose of its compliance with any benchmark under division (B) of this section, or the enforcement of that provision under division (C) of this section.

(E) All costs incurred by an electric distribution utility in complying with the requirements of this section shall be bypassable by any consumer that has exercised choice of supplier under section 4928.03 of the Revised Code.

Cite as R.C. § 4928.64

Amended by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

Amended by 129th General AssemblyFile No.125, SB 315, §101.01, eff. 9/10/2012.

Amended by 128th General AssemblyFile No.48, SB 232, §1, eff. 6/17/2010.

Amended by 128th General Assemblych.48, HB 2, §101.01, eff. 7/1/2009.

Effective Date: 2008 SB221 07-31-2008

4928.641 [Effective 9/12/2014] Costs being recovered through bypassable charge.

(A) If an electric distribution utility has executed a contract before April 1, 2014, to procure renewable energy resources and there are ongoing costs associated with that contract that are being recovered from customers through a bypassable charge as of the effective date of S.B. 310 of the 130th general assembly, that cost recovery shall continue on a bypassable basis until the prudently incurred costs associated with that contract are fully recovered.

(B) Division (A) of this section applies only to costs associated with the original term of a contract described in that division and entered into before April 1, 2014. This section does not permit recovery of costs associated with an extension of such a contract. This section does not permit recovery of costs associated with an amendment of such a contract if that amendment was made on or after April 1, 2014.

Added by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

4928.643 [Effective 9/12/2014] Baselines for compliance with qualified renewable energy resource requirements.

(A) Except as provided in division (B) of this section and section 4928.644 of the Revised Code, the baseline for an electric distribution utility's or an electric services company's compliance with the qualified renewable energy resource requirements of section 4928.64 of the Revised Code shall be the average of total kilowatt hours sold by the utility or company in the preceding three calendar years to the following:

(1) In the case of an electric distribution utility, any and all retail electric consumers whose electric load centers are served by that utility and are located within the utility's certified territory;

(2) In the case of an electric services company, any and all retail electric consumers who are served by the company and are located within this state.

(B) Beginning with compliance year 2014, a utility or company may choose for its baseline for compliance with the qualified renewable energy resource requirements of section 4928.64 of the Revised Code to be the total kilowatt hours sold to the applicable consumers, as described in division (A)(1) or (2) of this section, in the applicable compliance year.

(C) A utility or company that uses the baseline permitted under division (B) of this section may use the baseline described in division (A) of this section in any subsequent compliance year. A utility or company that makes this switch shall use the baseline described in division (A) of this section for at least three consecutive compliance years before again using the baseline permitted under division (B) of this section.

Added by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

4928.644 [Effective 9/12/2014] Adjustments to baselines.

The public utilities commission may reduce either baseline described in section 4928.643 of the Revised Code to adjust for new economic growth in the electric distribution utility's certified territory or in the electric services company's service area in this state.

Added by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

4928.645 Use of renewable energy credits.

(A) An electric distribution utility or electric services company may use, for the purpose of complying with the requirements under divisions (B)(1) and (2) of section 4928.64 of the Revised Code, renewable energy credits any time in the five calendar years following the date of their purchase or acquisition from any entity, including, but not limited to, the following:

(1) A mercantile customer ;

(2) An owner or operator of a hydroelectric generating facility that is located at a dam on a river, or on any water discharged to a river, that is within or bordering this state or within or bordering an adjoining state, or that produces power that can be shown to be deliverable into this state;

(3) A seller of compressed natural gas that has been produced from biologically derived methane gas, provided that the seller may only provide renewable energy credits for metered amounts of gas.

(B)

(1) The public utilities commission shall adopt rules specifying that one unit of credit shall equal one megawatt hour of electricity derived from renewable energy resources, except that, for a generating facility of seventy-five megawatts or greater that is situated within this state and has committed by December 31, 2009, to modify or retrofit its generating unit or units to enable the facility to generate

principally from biomass energy by June 30, 2013, each megawatt hour of electricity generated principally from that biomass energy shall equal, in units of credit, the product obtained by multiplying the actual percentage of biomass feedstock heat input used to generate such megawatt hour by the quotient obtained by dividing the then existing unit dollar amount used to determine a renewable energy compliance payment as provided under division (C)(2)(b) of section 4928.64 of the Revised Code by the then existing market value of one renewable energy credit, but such megawatt hour shall not equal less than one unit of credit. Renewable energy resources do not have to be converted to electricity in order to be eligible to receive renewable energy credits. The rules shall specify that, for purposes of converting the quantity of energy derived from biologically derived methane gas to an electricity equivalent, one megawatt hour equals 3,412,142 British thermal units.

(2) The rules also shall provide for this state a system of registering renewable energy credits by specifying which of any generally available registries shall be used for that purpose and not by creating a registry. That selected system of registering renewable energy credits shall allow a hydroelectric generating facility to be eligible for obtaining renewable energy credits and shall allow customer-sited projects or actions the broadest opportunities to be eligible for obtaining renewable energy credits.

Renumbered from § 4928.65 by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

Effective Date: 2008 SB221 07-31-2008; 2009 HB2 07-01-2009

4928.65 [Effective Until 9/12/2014] Using renewable energy credits.

An electric distribution utility or electric services company may use renewable energy credits any time in the five calendar years following the date of their purchase or acquisition from any entity, including, but not limited to, a mercantile customer or an owner or operator of a hydroelectric generating facility that is located at a dam on a river, or on any water discharged to a river, that is within or bordering this state or within or bordering an adjoining state, for the purpose of complying with the renewable energy and solar energy resource requirements of division (B)(2) of section 4928.64 of the Revised Code. The public utilities commission shall adopt rules specifying that one unit of credit shall equal one megawatt hour of electricity derived from renewable energy resources, except that, for a generating facility of seventy-five megawatts or greater that is situated within this state and has committed by December 31, 2009, to modify or retrofit its generating unit or units to enable the facility to generate principally from biomass energy by June 30, 2013, each megawatt hour of electricity generated principally from that biomass energy shall equal, in units of credit, the product obtained by multiplying the actual percentage of biomass feedstock heat input used to generate such megawatt hour by the quotient obtained by dividing the then existing unit dollar amount used to determine a renewable energy compliance payment as provided under division (C)(2)(b) of section 4928.64 of the Revised Code by the then existing market value of one renewable energy credit, but such megawatt hour shall not equal less than one unit of credit. The rules also shall provide for this state a system of registering renewable energy credits by specifying which of any generally available registries shall be used for that purpose and not by creating a registry. That selected system of registering renewable energy credits shall allow a hydroelectric generating facility to be eligible for obtaining renewable energy credits and shall allow customer-sited projects or actions the broadest opportunities to be eligible for obtaining renewable energy credits.

Cite as R.C. § 4928.65

Renumbered as § 4928.645 by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

4928.65 [Effective 9/12/2014] Adoption of rules governing disclosure of costs to

customers of the renewable energy resource, energy efficiency savings, and peak demand reduction requirements.

(A) Not later than January 1, 2015, the public utilities commission shall adopt rules governing the disclosure of the costs to customers of the renewable energy resource, energy efficiency savings, and peak demand reduction requirements of sections 4928.64 and 4928.66 of the Revised Code. The rules shall include both of the following requirements:

(1) That every electric distribution utility list, on all customer bills sent by the utility, including utility consolidated bills that include both electric distribution utility and electric services company charges, the individual customer cost of the utility's compliance with all of the following for the applicable billing period:

(a) The renewable energy resource requirements under section 4928.64 of the Revised Code, subject to division (B) of this section;

(b) The energy efficiency savings requirements under section 4928.66 of the Revised Code;

(c) The peak demand reduction requirements under section 4928.66 of the Revised Code.

(2) That every electric services company list, on all customer bills sent by the company, the individual customer cost, subject to division (B) of this section, of the company's compliance with the renewable energy resource requirements under section 4928.64 of the Revised Code for the applicable billing period.

(B)

(1) For purposes of division (A)(1)(a) of this section, the cost of compliance with the renewable energy resource requirements shall be calculated by multiplying the individual customer's monthly usage by the combined weighted average of renewable-energy-credit costs, including solar-renewable-energy-credit costs, paid by all electric distribution utilities, as listed in the commission's most recently available alternative energy portfolio standard report.

(2) For purposes of division (A)(2) of this section, the cost of compliance with the renewable energy resource requirements shall be calculated by multiplying the individual customer's monthly usage by the combined weighted average of renewable-energy-credit costs, including solar-renewable-energy-credit costs, paid by all electric services companies, as listed in the commission's most recently available alternative energy portfolio standard report.

(C) The costs required to be listed under division (A)(1) of this section shall be listed on each customer's monthly bill as three distinct line items. The cost required to be listed under division (A)(2) of this section shall be listed on each customer's monthly bill as a distinct line item.

Cite as R.C. § 4928.65

Added by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

4928.66 [Effective Until 9/12/2014] Implementing energy efficiency programs.

(A)

(1)

(a) Beginning in 2009, an electric distribution utility shall implement energy efficiency programs that achieve energy savings equivalent to at least three-tenths of one per cent of the total, annual average, and normalized kilowatt-hour sales of the electric distribution utility during the preceding three calendar years to customers in this state. An energy efficiency program may include a combined heat and power system placed into service or retrofitted on or after the effective date of the amendment of this section by S.B. 315 of the 129th general assembly, or a waste energy recovery system placed into service or retrofitted on or after the same date, except that a waste energy recovery system described in division (A)(38)(b) of section 4928.01 of the Revised Code may be included only if it was placed into service between January 1, 2002, and December 31, 2004. For a waste energy recovery or combined heat and power system, the savings shall be as estimated by the public utilities commission. The savings requirement, using such a three-year average, shall increase to an additional five-tenths of one per cent in 2010, seven-tenths of one per cent in 2011, eight-tenths of one per cent in 2012, nine-tenths of one per cent in 2013, one per cent from 2014 to 2018, and two per cent each year thereafter, achieving a cumulative, annual energy savings in excess of twenty-two per cent by the end of 2025. For purposes of a waste energy recovery or combined heat and power system, an electric distribution utility shall not apply more than the total annual percentage of the electric distribution utility's industrial-customer load, relative to the electric distribution utility's total load, to the annual energy savings requirement.

(b) Beginning in 2009, an electric distribution utility shall implement peak demand reduction programs designed to achieve a one per cent reduction in peak demand in 2009 and an additional seventy-five hundredths of one per cent reduction each year through 2018. In 2018, the standing committees in the house of representatives and the senate primarily dealing with energy issues shall make recommendations to the general assembly regarding future peak demand reduction targets.

(2) For the purposes of divisions (A)(1)(a) and (b) of this section:

(a) The baseline for energy savings under division (A)(1)(a) of this section shall be the average of the total kilowatt hours the electric distribution utility sold in the preceding three calendar years, and the baseline for a peak demand reduction under division (A)(1)(b) of this section shall be the average peak demand on the utility in the preceding three calendar years, except that the commission may reduce either baseline to adjust for new economic growth in the utility's certified territory.

(b) The commission may amend the benchmarks set forth in division (A)(1)(a) or (b) of this section if, after application by the electric distribution utility, the commission determines that the amendment is necessary because the utility cannot reasonably achieve the benchmarks due to regulatory, economic, or technological reasons beyond its reasonable control.

(c) Compliance with divisions (A)(1)(a) and (b) of this section shall be measured by including the effects of all demand-response programs for mercantile customers of the subject electric distribution utility, all waste energy recovery systems and all combined heat and power systems, and all such mercantile customer-sited energy efficiency, including waste energy recovery and combined heat and power, and peak demand reduction programs, adjusted upward by the appropriate loss factors. Any mechanism designed to recover the cost of energy efficiency, including waste energy recovery and combined heat and power, and peak demand reduction programs under divisions (A)(1)(a) and (b) of this section may exempt mercantile customers that commit their demand-response or other customer-sited capabilities, whether existing or new, for integration into the electric distribution utility's demand-response, energy efficiency, including waste energy recovery and combined heat and power, or peak demand reduction programs, if the commission determines that that exemption reasonably encourages such customers to commit those capabilities to those programs. If a mercantile customer makes such existing or new demand-response, energy efficiency, including waste energy recovery and combined heat and power, or peak demand reduction capability available to an electric distribution utility pursuant to division (A)(2)(c) of this section, the electric utility's baseline under division (A)(2)(a) of this section shall be adjusted to exclude the effects of all such demand-response, energy efficiency, including waste energy recovery and combined heat and power, or peak demand reduction programs that may have existed during the period used to establish the baseline. The baseline also shall be normalized for changes in numbers of customers, sales, weather, peak demand, and other appropriate factors so that the compliance measurement is not unduly influenced by factors outside the control of the electric distribution utility.

(d) Programs implemented by a utility may include demand-response programs, smart grid investment programs, provided that such programs are demonstrated to be cost-beneficial, customer-sited programs, including waste energy recovery and combined heat and power systems, and transmission and distribution infrastructure improvements that reduce line losses. Division (A)(2)(c) of this section shall be applied to include facilitating efforts by a mercantile customer or group of those customers to offer customer-sited demand-response, energy efficiency, including waste energy recovery and combined heat and power, or peak demand reduction capabilities to the electric distribution utility as part of a reasonable arrangement submitted to the commission pursuant to section 4905.31 of the Revised Code.

(e) No programs or improvements described in division (A)(2)(d) of this section shall conflict with any statewide building code adopted by the board of building standards.

(B) In accordance with rules it shall adopt, the public utilities commission shall produce and docket at the commission an annual report containing the results of its verification of the annual levels of energy efficiency and of peak demand reductions achieved by each electric distribution utility pursuant to division (A) of this section. A copy of the report shall be provided to the consumers' counsel.

(C) If the commission determines, after notice and opportunity for hearing and based upon its report under division (B) of this section, that an electric distribution utility has failed to comply with an energy efficiency or peak demand reduction requirement of division (A) of this section, the commission shall assess a forfeiture on the utility as provided under sections 4905.55 to 4905.60 and 4905.64 of the Revised Code, either in the amount, per day per undercompliance or noncompliance, relative to the period of the report, equal to that prescribed for noncompliances under section 4905.54 of the Revised Code, or in an amount equal to the then existing market value of one renewable energy credit per megawatt hour of undercompliance or noncompliance. Revenue from any forfeiture assessed under this division shall be deposited to the credit of the advanced energy fund created under section 4928.61 of the Revised Code.

(D) The commission may establish rules regarding the content of an application by an electric distribution utility for commission approval of a revenue decoupling mechanism under this division. Such an application shall not be considered an application to increase rates and may be included as part of a proposal to establish, continue, or expand energy efficiency or conservation programs. The commission by order may approve an application under this division if it determines both that the revenue decoupling mechanism provides for the recovery of revenue that otherwise may be forgone by the utility as a result of or in connection with the implementation by the electric distribution utility of any energy efficiency or energy conservation programs and reasonably aligns the interests of the utility and of its customers in favor of those programs.

(E) The commission additionally shall adopt rules that require an electric distribution utility to provide a customer upon request with two years' consumption data in an accessible form.

Cite as R.C. § 4928.66

Amended by 129th General AssemblyFile No.125, SB 315, §101.01, eff. 9/10/2012.

Effective Date: 2008 SB221 07-31-2008

4928.66 [Effective 9/12/2014] Implementing energy efficiency programs.

(A)

(1)

(a) Beginning in 2009, an electric distribution utility shall implement energy efficiency programs that achieve energy savings equivalent to at least three-tenths of one per cent of the total, annual average, and normalized kilowatt-hour sales of the electric distribution utility during the preceding three calendar years to customers in this state. An energy efficiency program may include a combined heat and power system placed into service or retrofitted on or after the effective date of the amendment of this section by S.B. 315 of the 129th general assembly, September 10, 2012, or a waste energy recovery system placed into service or retrofitted on or after September 10, 2012, except that a waste energy recovery system described in division (A)(38)(b) of section 4928.01 of the Revised Code may be included only if it was placed into service between January 1, 2002, and December 31, 2004. For a waste energy recovery or combined heat and power system, the savings shall be as estimated by the public utilities commission. The savings requirement, using such a three-year average, shall increase to an additional five-tenths of one per cent in 2010, seven-tenths of one per cent in 2011, eight-tenths of one per cent in 2012, nine-tenths of one per cent in 2013, and one per cent in 2014 . In 2015 and 2016, an electric distribution utility shall achieve energy savings equal to the result of subtracting the cumulative energy savings achieved since 2009 from the product of multiplying the baseline for energy savings, described in division (A)(2)(a) of this section, by four and two-tenths of one per cent. If the result is zero or less for the year for which the calculation is being made, the utility shall not be required to achieve additional energy savings for that year, but may achieve additional energy savings for that year. Thereafter, the annual savings requirements shall be, for years 2017, 2018, 2019, and 2020, one per cent of the baseline, and two per cent each year thereafter, achieving cumulative energy savings in excess of twenty-two per cent by the end of 2027. For purposes of a waste energy recovery or combined heat and power system, an electric distribution utility shall not apply more than the total annual percentage of the electric distribution utility's industrial-customer load, relative to the electric distribution utility's total load, to the annual energy savings requirement.

(b) Beginning in 2009, an electric distribution utility shall implement peak demand reduction programs designed to achieve a one per cent reduction in peak demand in 2009 and an additional seventy-five hundredths of one per cent reduction each year through 2014. In 2015 and 2016, an electric distribution utility shall achieve a reduction in peak demand equal to the result of subtracting the cumulative peak demand reductions achieved since 2009 from the product of multiplying the baseline for peak demand reduction, described in division (A)(2)(a) of this section, by four and seventy-five hundredths of one per cent. If the result is zero or less for the year for which the calculation is being made, the utility shall not be required to achieve an additional reduction in peak demand for that year, but may achieve an additional reduction in peak demand for that year. In 2017 and each year thereafter through 2020, the utility shall achieve an additional seventy-five hundredths of one per cent reduction in peak demand .

(2) For the purposes of divisions (A)(1)(a) and (b) of this section:

(a) The baseline for energy savings under division (A)(1)(a) of this section shall be the average of the total kilowatt hours the electric distribution utility sold in the preceding three calendar years . The baseline for a peak demand reduction under division (A)(1)(b) of this section shall be the average peak demand on the utility in the preceding three calendar years, except that the commission may reduce either baseline to adjust for new economic growth in the utility's certified territory. Neither baseline shall include the load and usage of any of the following customers:

(i) Beginning January 1, 2017, a customer for which a reasonable arrangement has been approved under section 4905.31 of the Revised Code;

(ii) A customer that has opted out of the utility's portfolio plan under section 4928.6611 of the Revised Code;

(iii) A customer that has opted out of the utility's portfolio plan under Section 8 of S.B. 310 of the 130th general assembly.

(b) The commission may amend the benchmarks set forth in division (A)(1)(a) or (b) of this section if, after application by the electric distribution utility, the commission determines that the amendment is necessary because the utility cannot reasonably achieve the benchmarks due to regulatory, economic, or technological reasons beyond its reasonable control.

(c) Compliance with divisions (A)(1)(a) and (b) of this section shall be measured by including the effects of all demand-response programs for mercantile customers of the subject electric distribution utility, all waste energy recovery systems and all combined heat and power systems, and all such mercantile customer-sited energy efficiency, including waste energy recovery and combined heat and power, and peak demand reduction programs, adjusted upward by the appropriate loss factors. Any mechanism designed to recover the cost of energy efficiency, including waste energy recovery and combined heat and power, and peak demand reduction programs under divisions (A)(1)(a) and (b) of this section may exempt mercantile customers that commit their demand-response or other customer-sited capabilities, whether existing or new, for integration into the electric distribution utility's demand-response, energy efficiency, including waste energy recovery and combined heat and power, or peak demand reduction programs, if the commission determines that that exemption reasonably encourages such customers to commit those capabilities to those programs. If a mercantile customer makes such existing or new demand-response, energy efficiency, including waste energy recovery and combined heat and power, or peak demand reduction capability available to an electric distribution utility pursuant to division (A)(2)(c) of this section, the electric utility's baseline under division (A)(2)(a) of this section shall be adjusted to exclude the effects of all such demand-response, energy efficiency, including waste energy recovery and combined heat and power, or peak demand reduction programs that may have existed during the period used to establish the baseline. The baseline also shall be normalized for changes in numbers of customers, sales, weather, peak demand, and other appropriate factors so that the compliance measurement is not unduly influenced by factors outside the control of the electric distribution utility.

(d)

(i) Programs implemented by a utility may include the following:

(I) Demand-response programs ;

(II) Smart grid investment programs, provided that such programs are demonstrated to be cost-beneficial ;

(III) Customer-sited programs, including waste energy recovery and combined heat and power systems ;

(IV) Transmission and distribution infrastructure improvements that reduce line losses ;

(V) Energy efficiency savings and peak demand reduction that are achieved, in whole or in part, as a result of funding provided from the universal service fund established by section 4928.51 of the Revised Code to benefit low-income customers through programs that include, but are not limited to, energy audits, the installation of energy efficiency insulation, appliances, and windows, and other weatherization measures.

(ii) No energy efficiency or peak demand reduction achieved under divisions (A)(2)(d)(i)(IV) and (V) of this section shall qualify for shared savings.

(iii) Division (A)(2)(c) of this section shall be applied to include facilitating efforts by a mercantile customer or group of those customers to offer customer-sited demand-response, energy efficiency, including waste energy recovery and combined heat and power, or peak demand reduction capabilities to the electric distribution utility as part of a reasonable arrangement submitted to the commission pursuant to section 4905.31 of the Revised Code.

(e) No programs or improvements described in division (A)(2)(d) of this section shall conflict with any statewide building code adopted by the board of building standards.

(B) In accordance with rules it shall adopt, the public utilities commission shall produce and docket at the commission an annual report containing the results of its verification of the annual levels of energy efficiency and of peak demand reductions achieved by each electric distribution utility pursuant to division (A) of this section. A copy of the report shall be provided to the consumers' counsel.

(C) If the commission determines, after notice and opportunity for hearing and based upon its report under division (B) of this section, that an electric distribution utility has failed to comply with an energy efficiency or peak demand reduction requirement of division (A) of this section, the commission shall assess a forfeiture on the utility as provided under sections 4905.55 to 4905.60 and 4905.64 of the Revised Code, either in the amount, per day per undercompliance or noncompliance, relative to the period of the report, equal to that prescribed for noncompliances under section 4905.54 of the Revised Code, or in an amount equal to the then existing market value of one renewable energy credit per megawatt hour of undercompliance or noncompliance. Revenue from any forfeiture assessed under this division shall be deposited to the credit of the advanced energy fund created under section 4928.61 of the Revised Code.

(D) The commission may establish rules regarding the content of an application by an electric distribution utility for commission approval of a revenue decoupling mechanism under this division. Such an application shall not be considered an application to increase rates and may be included as part of a proposal to establish, continue, or expand energy efficiency or conservation programs. The commission by order may approve an application under this division if it determines both that the revenue decoupling mechanism provides for the recovery of revenue that otherwise may be forgone by the utility as a result of or in connection with the implementation by the electric distribution utility of any energy efficiency or energy conservation programs and reasonably aligns the interests of the utility and of its customers in favor of those programs.

(E) The commission additionally shall adopt rules that require an electric distribution utility to provide a customer upon request with two years' consumption data in an accessible form.

Cite as R.C. § 4928.66

Amended by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

Amended by 129th General AssemblyFile No.125, SB 315, §101.01, eff. 9/10/2012.

Effective Date: 2008 SB221 07-31-2008

4928.6610 [Effective 9/12/2014] Definitions for sections 4928.6611 to 4928.6616.

As used in sections 4928.6611 to 4928.6616 of the Revised Code:

(A) "Customer" means any customer of an electric distribution utility to which either of the following applies:

(1) The customer receives service above the primary voltage level as determined by the utility's tariff classification.

(2) The customer is a commercial or industrial customer to which both of the following apply:

(a) The customer receives electricity through a meter of an end user or through more than one meter at a single location in a quantity that exceeds forty-five million kilowatt hours of electricity for the preceding calendar year.

(b) The customer has made a written request for registration as a self-assessing purchaser pursuant to section 5727.81 of the Revised Code.

(B) "Energy intensity" means the amount of energy, from electricity, used or consumed per unit of production.

(C) "Portfolio plan" means the comprehensive energy efficiency and peak-demand reduction program portfolio plan required under rules adopted by the public utilities commission and codified in Chapter 4901:1-39 of the Administrative Code or hereafter recodified or amended.

Added by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

4928.6611 [Effective 9/12/2014] Opting out of portfolio plan.

Beginning January 1, 2017, a customer of an electric distribution utility may opt out of the opportunity and ability to obtain direct benefits from the utility's portfolio plan. Such an opt out shall extend to all of the customer's accounts, irrespective of the size or service voltage level that are associated with the activities performed by the customer and that are located on or adjacent to the customer's premises.

Added by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

4928.6612 [Effective 9/12/2014] Notice of intent.

Any customer electing to opt out under section 4928.6611 of the Revised Code shall do so by providing a verified written notice of intent to opt out to the electric distribution utility from which it receives service and submitting a complete copy of the opt-out notice to the secretary of the public utilities commission.

The notice provided to the utility shall include all of the following:

(A) A statement indicating that the customer has elected to opt out;

(B) The effective date of the election to opt out;

(C) The account number for each customer account to which the opt out shall apply;

(D) The physical location of the customer's load center;

(E) The date upon which the customer established, or plans to establish a process and implement, cost-effective measures to improve its energy efficiency savings and peak demand reductions.

Added by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

4928.6613 [Effective 9/12/2014] Effect of election to opt out.

Upon a customer's election to opt out under section 4928.6611 of the Revised Code and commencing on the effective date of the election to opt out, no account properly identified in the customer's verified notice under division (C) of section 4928.6612 of the Revised Code shall be subject to any cost recovery mechanism under section 4928.66 of the Revised Code or eligible to participate in, or directly benefit from, programs arising from electric distribution utility portfolio plans approved by the public utilities commission.

Added by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

4928.6614 [Effective 9/12/2014] Opting in.

(A) A customer subsequently may opt in to an electric distribution utility's portfolio plan after a previous election to opt out under section 4928.6611 of the Revised Code if both of the following apply:

(1) The customer has previously opted out for a period of at least three consecutive calendar years.

(2) The customer gives twelve months' advance notice of its intent to opt in to the public utilities commission and the electric distribution utility from which it receives service.

(B) A customer that opts in under this section shall maintain its opt-in status for three consecutive calendar years before being eligible subsequently to exercise its right to opt out after giving the utility twelve months' advance notice.

Added by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

4928.6615 [Effective 9/12/2014] Notice of intent to opt in.

Any customer electing to opt in under section 4928.6614 of the Revised Code shall do so by providing a written notice of intent to opt in to the electric distribution utility from which it receives service and submitting a complete copy of the opt-in notice to the secretary of the public utilities commission. The notice shall include all of the following:

(A) A statement indicating that the customer has elected to opt in;

(B) The effective date of the election to opt in;

(C) The account number for each customer account to which the opt in shall apply;

(D) The physical location of the customer's load center.

Added by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

4928.6616 [Effective 9/12/2014] Opt out customer report.

(A) Not later than sixty days after the effective date at a customer's election to opt out under section 4928.6611 of the Revised Code, the customer shall prepare and submit an initial report to the staff of the public utilities commission. The report shall summarize the projects, actions, policies, or practices that the customer may consider implementing, based on the customer's cost-effectiveness criteria, for the purpose of reducing energy intensity.

(B) For as long as the opt out is in effect, the customer shall, at least once every twenty-four months, commencing with the effective date of the election to opt out, prepare and submit, to the staff of the commission, an updated report. The updated report shall include a general description of any cumulative amount of energy-intensity reductions achieved by the customer during the period beginning on the effective date of the election to opt out and ending not later than sixty days prior to the date that the updated report is submitted.

(C) All reports filed under this section shall be verified by the customer.

(D) Upon submission of any updated report under division (B) of this section, the staff of the commission may request the customer to provide additional information on the energy-intensity-reducing projects, actions, policies, or practices implemented by the customer and the amount of energy-intensity reductions achieved during the period covered by the updated report.

(E) Any information contained in any report submitted under this section and any customer responses to requests for additional information shall be deemed to be confidential, proprietary, and a trade secret. No such information or response shall be publicly divulged without written authorization by the customer or used for any purpose other than to identify the amount of energy-intensity reductions achieved by the customer.

(F) If the commission finds, after notice and a hearing, that the customer has failed to achieve any substantial cumulative reduction in energy intensity identified by the customer in an updated report submitted under division (B) of this section, and if the failure is not excusable for good cause shown by the customer, the commission may suspend the opt out for the period of time that it may take the customer to achieve the cumulative reduction in energy intensity identified by the customer but no longer.

Added by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

4928.662 [Effective 9/12/2014] Measurement and determination of compliance with demand reduction requirements.

For the purpose of measuring and determining compliance with the energy efficiency and peak demand reduction requirements under section 4928.66 of the Revised Code, the public utilities commission shall count and recognize compliance as follows:

(A) Energy efficiency savings and peak demand reduction achieved through actions taken by customers or through electric distribution utility programs that comply with federal standards for either or both energy efficiency and peak demand reduction requirements, including resources associated with such savings or reduction that are recognized as capacity resources by the regional transmission organization operating in Ohio in compliance with section 4928.12 of the Revised Code, shall count toward compliance with the energy efficiency and peak demand reduction requirements.

(B) Energy efficiency savings and peak demand reduction achieved on and after the effective date of S.B. 310 of the 130th general assembly shall be measured on the higher of an as found or deemed basis, except that, solely at the option of the electric distribution utility, such savings and reduction achieved since 2006 may also be measured using this method. For new construction, the energy efficiency savings and peak demand reduction shall be counted based on 2008 federal standards, provided that when new construction replaces an existing facility, the difference in energy consumed, energy intensity, and peak demand between the new and replaced facility shall be counted toward meeting the energy efficiency and peak demand reduction requirements.

(C) The commission shall count both the energy efficiency savings and peak demand reduction on an annualized basis.

(D) The commission shall count both the energy efficiency savings and peak demand reduction on a gross savings basis.

(E) The commission shall count energy efficiency savings and peak demand reductions associated with transmission and distribution infrastructure improvements that reduce line losses. No energy efficiency or peak demand reduction achieved under division (E) of this section shall qualify for shared savings.

(F) Energy efficiency savings and peak demand reduction amounts approved by the commission shall continue to be counted toward achieving the energy efficiency and peak demand reduction requirements as long as the requirements remain in effect.

(G) Any energy efficiency savings or peak demand reduction amount achieved in excess of the requirements may, at the discretion of the electric distribution utility, be banked and applied toward achieving the energy efficiency or peak demand reduction requirements in future years.

Added by 130th General Assembly File No. TBD, SB 310, §1, eff. 9/12/2014.

4928.67 Standard contract or tariff providing for net energy metering.

(A)

(1) Except as provided in division (A)(2) of this section, an electric utility shall develop a standard contract or tariff providing for net metering. That contract or tariff shall be identical in rate structure, all retail rate components, and any monthly charges to the contract or tariff to which the same customer would be assigned if that customer were not a customer-generator.

(2) An electric utility shall also develop a separate standard contract or tariff providing for net metering for a hospital, as defined in section 3701.01 of the Revised Code, that is also a customer-generator, subject to all of the following:

(a) No limitation, including that in divisions (A)(31)(a) and (d) of section 4928.01 of the Revised Code, shall apply regarding the availability of the contract or tariff to such hospital customer-generators.

(b) The contract or tariff shall be based both upon the rate structure, rate components, and any charges to which the hospital would otherwise be assigned if the hospital were not a customer-generator and upon the market value of the customer-generated electricity at the time it is generated.

(c) The contract or tariff shall allow the hospital customer-generator to operate its electric generating facilities individually or collectively without any wattage limitation on size.

(B)

(1) Net metering under this section shall be accomplished using a single meter capable of registering the flow of electricity in each direction. If its existing electrical meter is not capable of measuring the flow of electricity in two directions, the customer-generator shall be responsible for all expenses involved in purchasing and installing a meter that is capable of measuring electricity flow in two directions.

(2) The electric utility, at its own expense and with the written consent of the customer-generator, may install one or more additional meters to monitor the flow of electricity in each direction.

(3) Consistent with the other provisions of this section, the measurement of net electricity supplied or generated shall be calculated in the following manner:

(a) The electric utility shall measure the net electricity produced or consumed during the billing period, in accordance with normal metering practices.

(b) If the electricity supplied by the electric utility exceeds the electricity generated by the customer-generator and fed back to the utility during the billing period, the customer-generator shall be billed for the net electricity supplied by the utility, in accordance with normal metering practices. If electricity is provided to the utility, the credits for that electricity shall appear in the next billing cycle.

(4) A net metering system used by a customer-generator shall meet all applicable safety and performance standards established by the national electrical code, the institute of electrical and electronics engineers, and underwriters laboratories.

(C) The public utilities commission shall adopt rules relating to additional control and testing requirements for customer-generators that the commission determines are necessary to protect public and worker safety and system reliability.

(D) An electric utility shall not require a customer-generator whose net metering system meets the standards and requirements provided for in divisions (B)(4) and (C) of this section to do any of the following:

(1) Comply with additional safety or performance standards;

(2) Perform or pay for additional tests;

(3) Purchase additional liability insurance.

Cite as R.C. § 4928.67

Effective Date: 10-05-1999; 2008 SB221 07-31-2008

4928.68 Rules establishing greenhouse gas emission reporting requirements.

To the extent permitted by federal law, the public utilities commission shall adopt rules establishing greenhouse gas emission reporting requirements, including participation in the climate registry, and carbon dioxide control planning requirements for each electric generating facility that is located in this state, is owned or operated by a public utility that is subject to the commission's jurisdiction, and emits greenhouse gases, including facilities in operation on the effective date of this section.

Cite as R.C. § 4928.68

Effective Date: 2008 SB221 07-31-2008

4928.69 No surcharge, service termination charge, exit fee, or transition charge.

Notwithstanding any provision of Chapter 4928. of the Revised Code and except as otherwise provided in an agreement filed with and approved by the public utilities commission under section 4905.31 of the Revised Code, an electric distribution utility shall not charge any person that is a customer of a municipal electric utility that is in existence on or before January 1, 2008, any surcharge, service termination charge, exit fee, or transition charge.

Cite as R.C. § 4928.69

Effective Date: 2008 SB221 07-31-2008

4928.70 Review of green pricing programs.

(A) The public utilities commission may periodically review any green pricing program offered in this state as part of competitive retail electric service. At the conclusion of a review, the commission may make recommendations to improve or expand the program subject of the review.

(B) The commission shall adopt rules necessary to carry out purposes of this section.

Cite as R.C. § 4928.70

Added by 129th General AssemblyFile No.125, SB 315, §101.01, eff. 9/10/2012.

4928.71 Study regarding customer choice; report.

The public utilities commission shall study whether increased energy efficiency, demand response, generation, and transmission provide increased opportunities for customer choice. The commission shall include in the study an evaluation of emerging technologies. The commission shall commence the study not later than eighteen months after the effective date of this section. At the conclusion of the study, the commission shall prepare a report of its findings and make the report available on its web site.

Cite as R.C. § 4928.71

Added by 129th General AssemblyFile No.125, SB 315, §101.01, eff. 9/10/2012.

4928.72 Multi-state study on the development of compressed natural gas infrastructures for transportation.

The public utilities commission may, in cooperation with the department of transportation, work with other states to develop a multi-state study on the development of compressed natural gas infrastructures for transportation.

Cite as R.C. § 4928.72

Added by 129th General AssemblyFile No.125, SB 315, §101.01, eff. 9/10/2012.