The Public Utilities Commission of Ohio

Thomas W. Johnson, Chairman

Energy Mandates Study Committee
December 8, 2014

Ohio | Public Utilities Commission

Chairman Balderson, Chairman Stautberg, members of the committee, thank you for the opportunity to again provide testimony to the Energy Mandates Study Committee on behalf of the Public Utilities Commission of Ohio.

As you know, my name is Tom Johnson and I serve as the chairman of the Public Utilities Commission of Ohio. My intention today is to answer many of the questions the Committee raised during my testimony on November 24.

In an attempt to best address your concerns, I have organized the questions into subject matter categories of costs to ratepayers and riders, third-party administrators, jobs and the PUCO's analysis of the U.S. EPA's Clean Power Plan. As I discussed with Chairmen Balderson and Stautberg, the PUCO will defer answering some questions until a later date, as these require further time for review and analysis. For example, to answer the more complicated questions about increased grid congestion and advanced energy, we simply need more time.

First I'll address the issue of the cost to ratepayers to comply with alternative energy and energy efficiency requirements. The PUCO would in main part direct you to riders to demonstrate the costs to ratepayers.

Riders are generally single-issue mechanisms designed to transparently recover specific costs. They are advantageous from a regulatory perspective because they allow the PUCO to examine specific costs without going through a lengthy distribution rate case process. In addition they allow for periodic reviews to ensure accuracy, and that only appropriate costs are being recovered by ratepayers. Often times riders are per kilowatt charges, but can also be fixed monthly charges, or a percentage of other costs. It is also important to note that a rider can provide a credit to customers. You also requested a list of the riders currently in place for electric distribution utilities. You will find that list included with other attachments to my testimony.

With regard to alternative energy, both electric distribution utilities and competitive retail electric suppliers must annually show a certain percentage of their sales that come from renewable energy sources. To achieve compliance with these requirements, electric utilities and suppliers purchase renewable energy credits, or RECs, from PUCO-certified renewable generators. The costs of these RECs are determined by the open market between buyers and sellers. I have provided a chart as an attachment labeled as **Exhibit A**, illustrating the 2012 report to the General Assembly regarding the average costs of RECs. The electric utilities and suppliers must demonstrate to the PUCO that they fulfilled their statutory requirements annually. The PUCO verifies and audits purchases of RECs from all companies that serve load in Ohio. In the case of utilities, costs are passed onto ratepayers of electric distribution utilities through alternative energy riders. Customers pay a per kilowatt hour charge assessed in each monthly bill, depending on their utility service territory and customer rate class. The average monthly charge for alternative energy riders is $0.001142 per kilowatt hour and the average monthly charge for energy efficiency and peak demand reduction riders is $0.007225 per kilowatt hour. Average monthly costs for the alternative energy riders are demonstrated in the attachment labeled **Exhibit B**. This particular type of rider is known as bypassable, which means that if a customer selects a competitive retail electric supplier they no longer pay the alternative energy rider charged by the electric distribution utility.

As I previously noted, competitive retail electric suppliers also must comply with renewable benchmarks, and comply the same way—by purchasing RECs. Competitive retail electric suppliers' rates are not set or approved by the Commission; therefore, they account for all of their costs in their price offers.

The cost to comply with energy efficiency and peak demand reduction standards works slightly differently. To better understand what qualifies to meet the energy efficiency and peak demand reduction standards, I'll define both. Energy efficiency (EE) means to reduce the amount of electrical energy consumed while maintaining, or improving the customer's existing level of functionality. Peak demand reduction (PDR) is the electrical energy usage reduction which the utility company is capable of achieving through actions taken by their customers at specific times. Because energy efficiency and peak demand reduction requirements apply only to electric distribution utilities, these costs are recovered through a nonbypassable rider. A nonbypassable rider is recovered from all customers of an electric distribution utility regardless of whether they shop for electric generation with the exception of those mercantile customers that pursued a rider exemption pursuant to provisions found in Senate Bill 221. The associated energy efficiency and peak demand reduction riders vary by utility and rate class. As an example, costs for residential customers range from $0.00189 to $0.0045666 per kilowatt hour. Using a residential average usage of 750 kilowatt hours per month that amounts to $1.42 to $3.42 per monthly bill. I've provided you with a breakdown of the energy efficiency rider costs based on average usage for all of Ohio's electric distribution utilities in the attachment labeled **Exhibit C**. However, I would keep in mind that people would debate whether all the costs in the EE/PDR riders are actually costs related to the mandates. I am providing you with total bill impacts range from 1.82% to 4.75%, as demonstrated in the attachment labeled **Exhibit D**.

This brings me to another cost question specifically raised by Senator Seitz at the last meeting. On the Industrial Energy Users of Ohio's website there is a cost calculator that allows users to input their monthly kWh usage, select their utility and rate class and have a monthly cost calculated that they are billed for compliance with the energy efficiency requirements. At your request we have looked into the calculations and results of the calculator and we believe they are correct.

Additionally, I was asked about the difference between payments made to third-party administrators and the shared savings that utilities receive for exceeding their energy efficiency targets. It is important to note that while both relate to energy efficiency, these two items are unrelated. Third-party administrators are essentially a tool electric utilities use to implement requirements, and shared saving is an incentive mechanism for utilities to exceed requirements.

Payments made to third-party administrators are made for contracting energy efficiency savings. These administrators partner with utilities to find and coordinate potential qualifying energy efficiency work or projects that will assist a utility in meeting its statutory energy efficiency obligations.

Shared savings is a mechanism to incent the utilities to achieve energy efficiency beyond what is statutorily required. When a utility administers its portfolio plan and is able to exceed its statutory requirements, it is also able to share in the cost savings that its customers will experience from the energy savings. The PUCO has reviewed each utility's energy efficiency and peak demand reduction programs and determined that, thus far, the programs of each utility are cost effective. In other words, the total energy cost savings of the customers, in the aggregate, exceeds the total costs of the programs. Shared savings returns a portion of this savings to the electric utility when the electric utility exceeds the statutory mandates.

Regarding what savings data is monitored -- the PUCO does evaluate all costs associated with energy efficiency achievements, including payments to third-party administrators and utilities are required to provide the PUCO with accurate data.

You also expressed interest in the data that utilities provide the PUCO, specifically related to the use of third-party administrators. The PUCO receives detailed information and data from public utilities (and from competitive suppliers) on a daily basis. Many times, the utility or other entities will claim that the information is confidential through trade secret or other legal protections. Before the PUCO publically releases or shares information of this nature, the PUCO requests the utility assert and make clear their legal grounds for protection of the information. In some instances, a utility is required to file a request for a protective order from the PUCO. Information is only kept confidential if there are legal grounds for keeping the information private. The list of third-party administrators has been determined to be public information, as this was part of the original case record. I have provided this as an attachment labeled **Exhibit E**.

I want to acknowledge another topic that was brought up at our last meeting. Several members of the committee wanted to know how many jobs have been created through the renewable and energy efficiency requirements. I do not have an answer to this question. As a regulatory agency, tracking and verifying jobs, whether they be green jobs or otherwise, is not considered by any PUCO processes. Nor does the PUCO have any reliable method by which it would do so.

I understand it may be of great interest to members of this committee and can offer some personal insight into the issue. My understanding is that there is no widely accepted definition of a green job. What one may consider to be, another may not.

As you know, the PUCO recently conducted technical analysis of the Clean Power Plan proposed by U.S. EPA earlier this year. The PUCO concentrated its analysis on the plan's effect on the electric grid with a focus on costs of implementing the plan as well as the potential impact on grid reliability. Our comments were submitted last Monday, December 1. I have provided you with a copy of these comments, as an attachment to my written testimony labeled as **Exhibit F**.

Within our comments, the PUCO highlights concern that the Clean Power Plan conflicts with the Federal Power Act, and jurisdiction that Congress has vested to the Federal Energy Regulatory Commission (FERC), and subsequently through the FERC, regional transmission organizations like PJM Interconnection.

In their comments to U.S. EPA, the Ohio Attorney General and the Ohio Environmental Protection Agency raise targeted arguments on the legality of the Clean Power Plan.

The PUCO cannot predict with certainty when the Clean Power Plan will be finalized, however in accordance with the federal notice of proposed rulemaking that was filed in June 2014, U.S. EPA will issue a final rule in June 2015.

Although the Clean Power Plan's compliance period is set to commence in 2020, it is of course possible that the timing and implementation structure may change with the final rule. Potential legal challenges over the final rule may impact the implementation of the Clean Power Plan, particularly if a stay is issued by the courts.

Chairmen and fellow members of the committee, thank you for the opportunity to participate in this important study. If you or members of the committee have questions about this topic, my staff and I will be happy to answer your questions.

2012 Report to the General Assembly for Renewable Pricing

Category	Ohio Electric Distribution Utilities Avg. $/REC	Ohio Competitive Retail Electric Service Providers Avg. $/REC
Ohio Solar	$212.23	$195.93
Other Solar	$58.75	$104.99
Ohio Non-Solar	$33.51	$13.08
Other Non-Solar	$24.93	$2.04

REC cost data were not provided by APN Starfirst, Border Energy Services, Dominion Retail, Energy Plus Holding, FirstEnergy Solutions, GDF Suez, Glacial Energy, Hess Corporation, Independence Energy Group, Linde Energy Services, Texas Retail Energy, or Verde Energy USA Ohio.

Alternative Energy Rider (AER)Typical Bill Cost as of December 4, 2014

	AEP		Dayton Power & Light	Duke Energy	FirstEnergy		
Customer Class	Columbus Southern Power	Ohio Power	DPL	Duke-Ohio	Cleveland Electric Illuminating	Ohio Edison	Toledo Edison
Average Residential	$ 1.31	$ 0.77	$ 0.62	$ 0.27	$ 1.30	$ 1.01	$ 0.77
Average Commercial	$ 506.52	$ 298.65	$ 248.04	$ 109.20	$ 501.60	$ 388.20	$ 297.30
Average Industrial	$ 9,928.80	$ 5,854.20	$ 4,960.80	$ 2,184.00	$ 9,738.00	$ 7,536.00	$ 5,778.00

Average Residential typical usage 750 kWh

Average Commercialtypical usage 300,000 kWh

Average Industrial typical usage 6,000,000 kWh

Energy Efficiency and Peak Demand Rider (EE/PDR) Typical Bill Cost as of December 4, 2014

	AEP		Dayton Power & Light	Duke Energy	FirstEnergy		
Customer Class	Columbus Southern Power	Ohio Power	DPL	Duke-Ohio	Cleveland Electric Illuminating	Ohio Edison	Toledo Edison
Average Residential	$ 3.42	$ 3.42	$ 3.43	$ 2.58	$ 3.31	$ 2.37	$ 1.42
Average Commercial	$ 1,001.70	$ 1,001.70	$ 762.27	$ 501.00	$ 512.40	$ 582.30	$ 948.90
Average Industrial	$ 5,719.80	$ 5,719.80	$ 13,050.60	$ 10,020.00	$ 5,076.00	$ 14,496.00	$ 15,606.00

Average Residential typical usage 750 kWh

Average Commercialtypical usage 300,000 kWh

Average Industrial typical usage 6,000,000 kWh

Alternative Energy and Energy Efficiency / Peak Demand Rider as a Percentage of Estimated Total Bill as of December 4, 2014

	AEP		Dayton Power & Light	Duke Energy	FirstEnergy		
Customer Class	Columbus Southern Power	Ohio Power	DPL	Duke-Ohio	Cleveland Electric Illuminating	Ohio Edison	Toledo Edison
Average Residential	3.61%	3.20%	3.64%	3.07%	4.75%	3.54%	2.25%
Average Commercial	3.59%	3.09%	3.05%	1.96%	2.80%	3.04%	3.54%
Average Industrial	2.47%	1.82%	2.96%	2.39%	2.63%	4.11%	3.89%

Average Residential typical usage 750 kWh

Average Commercialtypical usage 300,000 kWh

Average Industrial typical usage 6,000,000 kWh

Exhibit E

Third Party Administrators

FirstEnergy Ohio

Council of Small Enterprises (COSE)

County Commissioners Association

Industrial Energy Users-Ohio (IEU)

Ohio Hospital Association (OHA)

Ohio Manufacturers' Association (OMA)

Ohio Schools Council

Roth Brothers

The E Group

Association of Independent Colleges and Universities (AICUO)

AEP – Ohio

Ohio Hospital Association (OHA)

Ohio Manufacturers' Association (OMA)

Dayton Power and Light Company

Ohio Hospital Association (OHA)

Ohio Manufacturers' Association (OMA)

DUKE

Not applicable

DAYTON POWER AND LIGHT RIDERS

					Rate Schedule					
	Rider	Rider Name	Definition	Applicabilty	Residential	Residential Heating	Secondary	Primary	Primary-Substation	High Voltage
1	AER	Alternative Energy Rider	Provides recovery for advanced generation plant investments and compliance costs related to renewable energy portfolio standards.	Bypassable	$0.0008268/ kWh	$0.0008268/ kWh	$0.0008268/ kWh	$0.0008268/ kWh	$0.0008268/ kWh	$0.0008268/ kWh
2	EER	Energy Efficiency Rider	Recovers the costs associated with meeting the energy efficiency and peak demand reduction targets set forth in Section 4928.66 of the Ohio Revised Code.	Non-bypassable	$0.0045785 /kWh	$0.0045785 /kWh	$0.0035797 /kWh	$0.0025409/kWh	$0.0022489/kWh	$0.0021751/kWh
3	CBT	Competitive Bidding True-up rider	The Competitive Bid True-up Rider (CBT) recovers the difference between amounts paid to suppliers for the delivery of SSO supply, as a result of the Competitive Bidding Process (CBP) auction(s), and amounts billed to SSO customers through the Competitive Bidding (CB) Rate. This Rider also recovers costs associated with administering and implementing the CBP. These costs include CBP auction costs, CBP consultant fees, PUCO consultant fees, audit costs, and supplier default costs (if any).	Bypassable (Deferred balances exceedign 10% will be recovered in Rider RR)	$0.0001619 /kWh	$0.0001619 /kWh	$0.0001619 /kWh	$0.0001619 /kWh	$0.0001619 /kWh	$0.0001619 /kWh
4	ESSC	Electric Service Stability Charge	Intended to compensate DP&L for providing stabilized rates for customers and Provider of Last Resort Service. Replaces Rider RSC	Non-bypassable	(0-750kWh) $0.0103362 /kWh (over 750kWh) $0.0084287 /kWh	(0-750kWh) $0.0103362 /kWh (over 750kWh) $0.0084287 /kWh Summer (over 750kWh) $0.0050540/kWh Winter	Billed Demand over 5kW $1.2104318/kW Energy (0-1500kWh) $0.0101459/kWh Energy (1501-125000kWh) $0.0044547/kWh Energy (over 125000kWh) $0.0037842/kWh Maximum Charge $0.0236440	Billed Demand $1.4208780/kW Energy Charge $0.0033887/kWh Maximum Charge $0.0237494/kWh	Billed Demand $1.5092978/kW Energy Charge $0.0032482/kW	Billed Demand $1.5395867/kW Energy Charge $0.0033476/kW
5	TCRR-B	Transmission Cost Recovery Rider-Bypassable	Recovers all market-based transmission, ancillary and congestion costs or credits, imposed on or charged to the Company by FERC or PJM, which are not recovered in the TCRR-N	Bypassable	$0.0002656/kWh	$0.0023998/kWh	Demand (over 5kW) $(0.0366275)/kW Energy (0-1500kWh) $0.0001591/kWh Energy (over 1500kWh) $0.0003891/kWh Maximum Charge $0.0064142/kWh	Demand Charge $(0.0490713)/kW Energy Charge $0.0003839/kWh Maximum Charge $0.0060225/kWh	Demand Charge $(0.0490713)/kW Energy Charge $0.0003839/kWh	Demand Charge $(0.0490713)/kW Energy Charge $0.0003839/kWh
6	TCRR-N	Transmission Cost Recovery Rider-Nonbypassable	Recovers transmission-related costs imposed on or charged to the Company by FERC or PJM	Non-bypassable	$0.0049232/kWh	$0.0049232/kWh	Demand (over 5kW) $1.6727848/kW Energy (0-1500kWh) $0.0082777/kWh Energy (over 1500kWh) $0.0005034/kWh Maximum Charge $0.0152147/kWh	Demand Charge $1.4784868/kW Energy Charge $0.0005034/kWh Reactive Demand $0.3481988/kVar Maximum Charge $0.0060225/kWh	Demand Charge $1.3126352/kW Energy Charge $0.0005034/kWh Reactive Demand $0.3923485/kVar	Demand Charge $1.7026292/kW Energy Charge $0.0005034/kWh Reactive Demand $0.5077477/kVar
7	USF	Universal Service Fund Rider	Provides qualified Low-Income Customers in Ohio with income-based bills and energy efficiency education programs.	Non-bypassable	$0.0039788/kWh (0-833,000kWh) $0.0005700/kWh (over 833,000kWh)					
8	EDR	Economic Development Rider	Allows for the recovery of costs incurred as a result of economic development and job retention programs including foregone revenues	Non-bypassable	$0.0015023/kWh	$0.0015023/kWh	$0.0009036/kWh	$0.0002730/kWh	$0.0000618/kWh	$0.0000020/kWh
9	RR	Reconciliation Rider Nonbypassable	Recovers the deferred balances that exceed 10% of the base amount of riders FUEL, RPM, AER, and CBT	Non-byassable	$0.0003668/kWh	$0.0003668/kWh	$0.0003668/kWh	$0.0003668/kWh	$0.0003668/kWh	$0.0003668/kWh
10	CBP	Competitive Bidding Rate	Recovers supply costs associated with the Competitive Bidding Process	Bypassable	(0-750) $0.0057940/kWh (>750) $0.0048795/kWh	(0-750) $0.0057940/kWh Summer (>750) $0.0048795/kWh Winter (>750) $0.0032561/kWh	Demand Charge (>5kW) $0.6224697/kW Energy (0-1500kWh) $0.0067971/kWh (1500-125000kWh) $0.0028096/kWh (>125000kWh) $0.0024566/kWh Maximum Charge $0.0168763/kWh	Demand Charge: $0.7322984/kW Energy Charge: $0.0026711/kWh Maximim Charge: $0.0181684	Billed Demand $0.7716340/kW Energy Charge $0.0025789/kW	Billed Demand $0.7569049/kW Energy Charge $0.0025535/kW
11	RPM	PJM RPM Rider	Compensates DP&L for RPM related charges from PJM	Bypassable	$0.0018269/kWh	$0.0018269/kWh	Demand Charge (>5kW) $0.5168045/kW Energy (0-1500kWh) $0.0032447/kWh Maximum Charge $0.0018205/kWh	Demand Charge $0.7823587/kW	Demand Charge $0.7823587/kW	Demand Charge $0.7823587/kW

Dayton Power and Light Riders - As of 11/31/2014

#	Rider	Rider Name	Definition	Applicabilty	Rate Schedule: Residential	Residential Heating	Secondary	Primary	Primary-Substation	High Voltage
12		Excise Tax Surcharge Rider	Assessed to all non-federal government customers on all monthly billing kWh. Some Commercial and Industrial consumers are exempt from this tax, but must register with the Company prior to being released from payment of this surcharge.		(0-2000kWh) $0.00465/kWh (2001-15000kWh) $0.00419/kWh (over 15,000kWh) $0.00363/kWh	(0-2000kWh) $0.00465/kWh (2001-15000kWh) $0.00419/kWh (over 15,000kWh) $0.00363/kWh	(0-2000kWh) $0.00465/kWh (2001-15000kWh) $0.00419/kWh (over 15,000kWh) $0.00363/kWh	(0-2000kWh) $0.00465/kWh (2001-15000kWh) $0.00419/kWh (over 15,000kWh) $0.00363/kWh	(0-2000kWh) $0.00465/kWh (2001-15000kWh) $0.00419/kWh (over 15,000kWh) $0.00363/kWh	(0-2000kWh) $0.00465/kWh (2001-15000kWh) $0.00419/kWh (over 15,000kWh) $0.00363/kWh
13	**FUEL**	Fuel Rider	Recovers fuel-related costs associated with providing generation service to customers	Bypassable	$0.0270091/kWh	$0.0270091/kWh	$0.0270091/kWh	$0.0262468/kWh	$0.0259503/kWh	$0.0259503/kWh
14		Generation Tariffs	Standard Offer Generation Rates	Bypassable	(0-750kWh) $0.0481140/kWh (>750) $0.0359820	Summer: (0-750kWh) $0.0481140/kWh (>750) $0.0359820/kWh Winter: (0-750kWh) $0.0481140/kWh (>750) $0.0144450	Demand: (<5kW) $0.0000 (>5kW) $8.0831790/kW Energy: (0-1500kWh) $0.0500040/kWh (1500kWh-125000) $0.0120600/kWh (>125000) $0.0075330/kWh	Demand: $9.9701910/kW Energy: $0.0061020/kWh	Demand: $10.5404130/kW Energy: $0.0049500/kWh	Demand: $10.2951990/kW Energy: $0.0046980/kWh
15		Switching Fee Rider	Imposes a $5 fee for every switch to an Alternative Generation Supplier, as well as a $5 fee for a return to the SSO	Bypassable						

AMERICAN ELECTRIC POWER COMPANY

#	Rider	Rider Name	Definition	Other	Applicability	Rate RS	Rate RS-ES	Rate GS-1 ES
1	**USF**	Universal Service Fund	Universal service fund established by Ohio Amended Substitute Senate Bill No. 3. Applicable to all jurisdictional customers.	**Ohio Power Rate Zone** 0.72152/kWh (cents) for the first 833,000 kWh consumed each month and 0.01681 kWh (cents)for all kWh consumed each month in excess of 833,000 kWh. **Columbus Southern Power Rate Zone** 0.43882/kWh (cents) for the first 833,000 kWh consumed each month and 0.01830/kWh (cents) for all kWh consumed each month in excess of 833,000 kWh.	Non-bypassable			
2		Residential Distribution Credit	Establishes a credit for residential customers. This credit will expire May 31, 2015.	**Ohio Power & Columbus Southern Power Rate Zones** All customer bills subject to the provision of this rider, including any bills rendered under special contract, shall be adjusted by the rider credit of 3.5807% of base distribution revenue.				
3		Pilot Throughput Balancing Adjustment Rider	Establishes a decoupling mechanism and pilot project for the residential class. The rider was set at zero in 2012, but charges or credits commenced in 2013 after the company compared and calculated the previous fees are	See rate chart. All rates are cents per kWh.	Non-bypassable	**OP** 0.14837 **CSP** 0.16182	**OP** 0.14837 **CSP** 0.16182	
4	**DARR**	Deferred Asset Phase-In Rider	Allows for the recovery of phase-in costs associated with the Company's Deferred Asset Recovery Rider. Is replacing the Base Generation Capacity Rider.	**Ohio Power & Columbus Southern Power Rate Zones** All customer bills subject to the provisions of this rider, including any bills rendered under special contract, shall be adjusted by the Deferred Asset Phase-In Rider charge of 7.60% of the customer's base distribution charges schedules, excluding charges under any applicableunder the Company's riders.	Bypassable			

#	Rider	Rider Name	Definition	Other	Applicability	Rate RS	Rate RS-ES	Rate GS-1 ES
5	**GCR**	Generation Capacity Rider	Establishes seasonal as well as on-peak and off-peak rates as they pertain to generation capacity.	Rates are cents per kWh or dollars per month.	Bypassable	**OP** 0.1755	**OP** On-peak kWh 0.36343 Off-peak kWh 0.10012 **CSP** On-peak kWh 0.30371 Off-peak kWh 0.10419	**OP** On-peak kWh 0.26019 Off-peak kWh 0.05680
6	**TCRR**	Transmission Cost Recovery Rider	Recovers transmission costs. Uses projected costs and revenues.	All rates are cents per kWh or dollars per kW.	Non-bypassable	1.87674 cents per kWh	1.87674 cents per kWh	
7	**TCRR-U**	Transmission Under-Recovery Rider	Allows for the recovery of additional transmission costs to offset umder-recovery of costs to provide service. Expires 11/2015	Rates are either cents per kWh or dollars per kW.	Non-bypassable	0.03295 cents per kWh	0.03295 cents per kWh	
8		Energy Efficiency & Peak Demand Reduction Cost Recovery	Recover AEP's cost of complying with the energy savings and peak demand reduction programs. If approved by the Commission, mercantile customers that have committed their demand response or other customer-sited capabilities, whether existing or new, for integration into the Company's demand response, energy efficiency or peak demand reduction programs, may be exempted from this rider.	Rates are cents per kWh.	Non-bypassable	0.45666	0.45666	
9	**EDR**	Economic Development Cost Recovery	Mechanism to recover foregone revenue associated with an economic development customer discount.	11.44664% of the customer's distribution charges.	Non-bypassable			
10	**ESRR**	Enhanced Service Reliability	Provides funding for distribution system improvements including vegetation improvement	6.55776% of the customer's distribution charges.	Non-bypassable			
11		gridSMART	Allows for recovery of Smart Grid initiatives in AEP's territory.	Residential Customers - $0.51/month Non-Residential Customers $2.10/month	Non-bypassable			

#	Rider	Rider Name	Definition	Other	Applicability	Rate RS	Rate RS-ES	Rate GS-1 ES
12		Renewable Energy Credit Purchase Offer	Program allows customers taking electric service under the Company's standard service or open access distribution schedules that own or lease solar photovoltaic or small wind energy systems to sell RECs to the Company. Such systems must be located in the Company's service territory and	For each Renewable Energy Certificate (REC), the Company will pay the customer as follows (during the period August 1, 2008 - June 30, 2013)	Bypassable	Facility Type | $/REC 2011 | 2012 | 2013 Solar Photovoltaic | $ 300.00 | $ 262.50 | $ 262.50 Small Wind | $ 34.00 | $ 34.00 | $ 34.00		
13	RSR	Retail Stability Rider	Mechanism to adjust all customer bills by a charge per kWh for the purposes of retail stability. In 201X capacity deferrals will be recovered here.	All rates are in cents per kWh.	Non-bypassable	0.53154	0.53154	
14		Renewable Energy Technology Program	Allows customers taking electric service under the Company's standard service or open access distribution schedules that install a solar photovoltaic or wind energy system after July 1, 2011 and before June 30, 2013 to sell RECs (Renewable Energy Certificates) to the Company.	Please refer to tariff for information pertaining to incentive amounts for solar photovoltaic and wind systems.	Bypassable			
15	DIR	Distribution Investment Rider	Mechanism to adjust all customer bills by a percentage rate of the distribution charges for to recover distribution investment.	19.97891% of the customer's distribution charges.	Non-bypassable			
16		Storm Damage Recovery	Establishes rates to allow for the recovery of major storm restoration costs.	Residential Customers $2.38/month Non-Residential Customers $9.82/month	Non-bypassable			
17		Generation Resource Rider	Mechanism to adjust all customer bills for generation resource purposes.	Rate is $0.00	Non-bypassable			
18		Alternative Energy	Mechanism to adjust all customer bills with a charge per kWh to recover prudently-incurred alternative energy compliance costs.	**Ohio Power Rate Zone** Delivery Voltage | Charge (cents per kWh) Secondary | 0.10312 Primary | 0.09955 Subtransmission/Transmission | 0.09757 **Columbus Southern Power Rate Zone** Delivery Voltage | Charge (cents per kWh) Secondary | 0.17491 Primary | 0.16884 Subtransmission/Transmission | 0.16548	Bypassable			

#	Rider	Rider Name	Definition	Other	Applicability	Rate RS	Rate RS-ES	Rate GS-1 ES
19		Phase-In Recovery	Mechanism to recover on a phased-in basis the recovery of deferred fuel costs	**Ohio Power Rate Zone** Delivery Voltage — Charge (cents per kWh) Secondary — 0.4222 Primary — 0.4076 Subtransmission/Transmission — 0.3994 **Columbus Southern Power Rate Zone** Delivery Voltage — Charge (cents per kWh) Secondary — 0.00000 Primary — 0.00000 Subtransmission/Transmission — 0.00000	Non-bypassable			
20		Fixed Cost	Mechanism to adjust all customer bills with a per kWh charge for purposes of fixed fuel cost recovery.	**Ohio Power Rate Zone** Delivery Voltage — Charge (cents per kWh) Secondary — 0.59287 Primary — 0.5723 Subtransmission/Transmission — 0.5609 **Columbus Southern Power Rate Zone** Delivery Voltage — Charge (cents per kWh) Secondary — 0.74587 Primary — 0.72000 Subtransmission/Transmission — 0.70566	Bypassable			
21		Auction Phase-In	Mechanism to adjust all customer bills with a per kWh charge for purposes of a phased-in recovery of auction costs.	**Ohio Power Rate Zone** Delivery Voltage — Charge (cents per kWh) Secondary — 3.65622 Primary — 3.52938 Subtransmission/Transmission — 3.45906 **Columbus Southern Power Rate Zone** Delivery Voltage — Charge (cents per kWh) Secondary — 4.27045 Primary — 4.12230 Subtransmission/Transmission — 4.04018	Bypassable			

Rider	Rider Name	Definition	Other	Applicability	Rate RS	Rate RS-ES	Rate GS-1 ES
22	kWh Tax Rider	Applicable to all jurisdictional retail customers except that those who meet the eligibility requirements contained in section 5727.81 of the Ohio Revised Code may elect to self-assess this tax.	**Ohio Power & Columbus Southern Power Rate Zones** For the first 2,000 kWh used per month 0.465/kWh (cents) For the next 13,000 kWh used per month 0.419/kWh (cents) All kWh used in excess of 15,000 kWh per month 0.363/kWh (cents)				
23	Pool Termination Rider	Allows for the recovery of lost net revenue from retail customers based on the termination of the Pool Agreement.	Rate is $0.00				
24	Electronic Transfer Rider Provision	Funds AEP's electronic payment system.	For any General Service customer who agrees to make payments to the Company by electronic transfer, the 21 days provision in the Delayed Payment Charge in the General Service tariffs shall be modified to 22 days. If the 22nd day falls upon a weekend or the legal holidays of New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day, the payment must be received by the next business day to avoid the Delayed Payment Charge. In no event shall this Rider apply to Supplement No. 21.				
25	SEET Credit	Mechanism to adjust all customer bills with a charge per kWh for the purposes of SEET (significantly excessive earnings) credit	OP Rate Zone - NA CSP Rate Zone - $0.000358 per kWh				

OHIO EDISON COMPANY RIDERS

#	Rider	Rider Name	Definition	Applicability	Rate Schedule								Other
					RS	GS	GP	GSU	GT	STL	TRF	POL	
1	AER	Alternative Energy Resource Rider	The costs initially deferred by the Company and subsequently fully recovered through this Rider will be all costs associated with securing compliance with the alternative energy resource requirements including, but not limited to, all Renewable Energy Credits costs, any reasonable costs of administering the request for proposal, and applicable carrying costs. This rider is charged (for all rate classes) for all kWhs per kWh.	Bypassable	0.1340¢	0.1340¢	0.1294¢	0.1257¢	0.1256¢	0.1340¢	0.1340¢	0.1340¢	
2	AMI	Advanced Metering Infrastructure/ Modern Grid Rider	Cost recovery for Advanced Meter Installation. Not applicable to GT rate schedule. Charged to customers under all rate schedules (except STL) on a per customer, per bill basis. STL customers are charged per lighting unit, per month	Non-Bypassable	$0.2070	$1.0670	$15.0040	$17.0840	n/a	$0.0460	$0.2050	$0.2780	
3	BDC	Business Distribution Credit Rider	Applicable to any customer taking service under Rate Schedules GS or GP who on 4/30/09 took service under one of the following rate schedules and has not had a change of service address or a change to qualifying conditions subsequent to 4/30/09. Qualifying conditions are those in effect in the below rate schedules as they existed on 4/30/09 and continues to comply with the requirements of the previously applicable rate schedule set forth below: Electric Space Conditioning, All Electric Large General Service, Optional Electric Process Heating and Electric Boiler Load Management			Distribution charges shall be reduced by 2.000¢ per kWh for all kWhs consumed during winter billing periods	Distribution charges shall be reduced by 2.000¢ per kWh for all kWhs consumed during winter billing periods.						
4	CPP	Experimental Critical Peak Pricing	Voluntary experimental program, applied in lieu of the GEN Rider. Reflects time-of-day pricing, for all kWh per kWh for both summer and winter seasons			Capacity: 1.3625¢ Energy:6.8428¢ Capacity: 1.3625¢ Energy:6.8428¢ Capacity: 1.3625¢ Energy:4.0818¢ Capacity: 1.3625¢ Energy:6.0134¢ Capacity: 1.3625¢ Energy:6.8751¢ Capacity: 1.3625¢ Energy:3.8747¢	Capacity:1.0372¢ Energy:6.6100¢ Capacity:1.0372¢ Energy:6.6100¢ Capacity:1.0372¢ Energy:3.9430¢ Capacity:1.0372¢ Energy:5.8098¢ Capacity:1.0372¢ Energy:6.6422¢ Capacity:1.0372¢ Energy:3.7435¢	Capacity:0.8893¢ Energy:6.4281¢ Capacity:0.8893¢ Energy:6.4281¢ Capacity:0.8893¢ Energy:3.8344¢ Capacity:0.8893¢ Energy:5.6505¢ Capacity:0.8893¢ Energy:6.4601¢ Capacity:0.8893¢ Energy:3.6409¢	Capacity:0.7756¢ Energy:6.4218¢ Capacity:0.7756¢ Energy:6.4218¢ Capacity:0.7756¢ Energy:3.8307¢ Capacity:0.7756¢ Energy:5.6450¢ Capacity:0.7756¢ Energy:6.4538¢ Capacity:0.7756¢ Energy:3.6373¢				There is a Program Administrative Charge of $37.50 per month. With day-ahead notification, the applicable Midday-Peak CPP Charge shall change to 32.0667¢ per kWh during the summer as determined by the Company.
5	DCR	Delivery Capital Recovery Rider	Recovers the costs associated with delivery plant investments made since the date certain in Case No. 07-551-EL-AIR, exclusive of any delivery plant investments being recovered elsewhere.	Non-Bypassable	0.4099¢ per kWh	$1.4593 per kW of Billing Demand	$0.9861 per kW of Billing Demand	$0.4116 per kW of Billing Demand					
6	DRR	Delta Revenue Recovery Rider	Recovers the difference in revenue between the application of rates in the otherwise applicable rate schedule and the result of any economic development schedule, energy efficiency schedule, reasonable arrangement, or governmental special contract approved by the PUCO on or after 1/1/09. Charged for all kWhs per kWh	Non-Bypassable	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
7	DSE	Demand Side Management and Energy Efficiency Rider	Provides recovery for FE's EEPDR programs. Mercantile customers who enter EEPDR programs with FE are exempted from this rider.	Non-Bypassable	0.0450¢ 0.2716¢	0.0450¢ 0.2170¢	0.0450¢ 0.1491¢	0.0450¢ 0.2519¢	0.0450¢ 0.1966¢	0.0450¢ 0.0403¢	0.0450¢ 0.1566¢	0.0450¢ 0.0000¢	
8	DSM	Demand Side Management Rider	Applied to each kWh delivered during a billing month to all retail customers taking service under Rate Schedule RS	Non-Bypassable	$0.0000								
9	DUN	Dustribution Uncollectible Rider	Charged for all kWhs per kWh	Non-Bypassable	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	

10	EDR	Economic Development Rider	a. Residential Non-Standard Credit Provision- applicable to residential customers to which RDC Rider applies. Applied for all kWhs per kWh in excess of 500 kWhs per month, during winter billling periods	Non-bypassable	0.0000¢ (1.9000)¢ (1.9000)¢ (1.9000)¢ (1.9000)¢ 0.0000¢ (1.9000)¢								
			b. Interruptible Credit Provision- applicable to customers under PUCO-approved contracts containing interruptible provisions, in conjunction with ELR Rider, applied by unit of Curtailable Load as defined in Rider ELR (per kW)				($5.0000)	($5.0000)	($5.0000)				
			c. Non-Residential Credit Provision- for all kWhs per kWh						(0.0000)¢	(0.3579)¢	(1.5230)¢	(2.4799)¢	
			d. General Service- Transmission Provision						$8.0000 (1.7706)¢				
			e. Standard Charge Provision- recover the difference in revenues resulting from the application of rates in the otherwise applicable rate schedule and the application of credits in a, b, c and f of this rider				0.1777¢	0.1739¢					
			f. School Credit Provision- Credit applicable to public school					All Rider GEN charges for these rate classes shall be reduced by 8.693%					
			g. Infrastructure Improvement Provision- Recovers costs associated with certain economic expansion and new employment in Ohio		0.0478¢	0.0327¢	0.0120¢	0.0048¢	0.0015¢				
			h. Automaker Credit Provision- only applied to usage that exceeds baseline usage										(1.0000)¢ (1.2000)¢
			i. Automaker Charge Provision- Recover costs associated with implementation of the Automaker Credit Provision			0.0068¢							
11	ELR	Economic Load Response Program Rider	Demand Response program for high voltage, high demand users.										Priced per customer
12	FUEL	Fuel Rider	The Fuel Rider charge shall be reconciled to reflect the difference between actual and forecasted costs and the difference between actual and forecasted generation revenue and revenue collected under this Rider.	Bypassable	0.3267¢	0.3267¢	0.3154¢	0.3065¢	0.3062¢	0.3267¢	0.3267¢	0.3267¢	
13	GCR	Generation Cost Reconciliation Rider	Charged for all kWhs per kWh. For any given billing period, only the non-zero GCR charge will be applied.		0.3720¢ $0.0000	0.3720¢ $0.0000	0.3591¢ $0.0000	0.3490¢ $0.0000	0.3486¢ $0.0000	0.3720¢ $0.0000	0.3720¢ $0.0000	0.3720¢ $0.0000	
14	GEN	Generation Service Rider	For customers taking the SSO Generation Service from the Company. Charged for all kWhs per kWh unless otherwise noted.		Capacity:1.0893¢ Energy:6.0922¢ Capacity:1.0893¢ Energy:5.1165¢	Capacity:1.3625¢ Energy:6.0922¢ Capacity:1.3625¢ Energy:5.1165¢ Capacity:1.3625¢ Energy:10.7235¢ Capacity:1.3625¢ Energy:6.8428¢ Capacity:1.3625¢ Energy:4.0818¢ Capacity:1.3625¢ Energy:6.0134¢ Capacity:1.3625¢ Energy:6.8751¢	Capacity:1.0372¢ Energy:5.8850¢ Capacity:1.0372¢ Energy:4.9432¢ Capacity:1.0158¢ Energy:10.3588¢ Capacity:1.0372¢ Energy:6.6100¢ Capacity:1.0372¢ Energy:3.9430¢ Capacity:1.0372¢ Energy:5.8098¢ Capacity:1.0372¢ Energy:6.6422¢	Capacity:0.8893¢ Energy:5.7230¢ Capacity:0.8893¢ Energy:4.8077¢ Capacity:0.8893¢ Energy:10.0737¢ Capacity:0.8893¢ Energy:6.4281¢ Capacity:0.8893¢ Energy:3.8344¢ Capacity:0.8893¢ Energy:5.6505¢ Capacity:0.8893¢ Energy:6.4601¢	Capacity:0.7756¢ Energy:5.7174¢ Capacity:0.7756¢ Energy:4.8030¢ Capacity:0.7756¢ Energy:10.0638¢ Capacity:0.7756¢ Energy:6.4218¢ Capacity:0.7756¢ Energy:3.8307¢ Capacity:0.7756¢ Energy:5.6450¢ Capacity:0.7756¢ Energy:6.4538¢	Capacity:0.0000¢ Energy:6.0922¢ Capacity:0.0000¢ Energy:5.1165¢	Capacity:0.9373¢ Energy:6.0922¢ Capacity:0.9373¢ Energy:5.1165¢	Capacity:0.0000¢ Energy:6.0922¢ Capacity:0.0000¢ Energy:5.1165¢	

						Capacity:1.3625¢ Energy:3.8747¢	Capacity:1.0372¢ Energy:3.7435¢	Capacity:0.8893¢ Energy:3.6409¢	Capacity:0.7756¢ Energy:3.6373¢				
15	HNM	Hospital Net Metering Rider	Available to qualifying hospitals having self-generation equipment located on the Hospital's premises that operates in parallel with the Company's facilities.										Hospital shall be charged for all electricity used in accordance with the rate schedule for which the Hospital would otherwise qualify. All electricity generated by the Hospital shall be credited on an hourly basis for the time the Hospital's electricity is generated, at the locational marginal price of energy quoted by the applicable RTO.
16	LEX	Line Extension Cost Recovery Rider	Charged for all kWhs per kWh	Non-Bypassable	0.0009¢								
17	NDU	Non-Distribution Uncollectible Rider	Charged for all kWhs per kWh	Bypassable	0.0446¢								
18		Net Energy Metering Rider	Customer-generator facility must use as its fuel either solar, wind, biomass, landfill gas, or hydropower, or use a microturbine or a fuel cell located on the customer-generator's premises and is intended primarily to offset part or all of the customer's electricity requirements.		The provisions of this rider will be applied to the rate schedule to which the customer would be assigned if that customer were not a customer-generator. The customer-generator will be billed or credited charges and applicable riders as measure by the meter.								
19	NMB	Non-Market-Based Services Rider	Recovers non-market-based costs, fees, or charges imposed on or charged to the Company by FERC or a regional transmission organization, independent transmission operator, or similar organization approved by FERC. This Rider may be updated: 1) to account for changes in existing non-market-based costs, fees or charges and 2) to include any non-market-based costs, fees or charges that were not yet in effect on the effective date of this Rider and/or otherwise imposed on or charged to the Company by FERC or RTO.	Non-Bypassable	0.5131¢ per kWh	$1.7488 per kW of Billing Demand	$2.0283 per kW of Billing Demand	$1.6558 per kW of Billing Demand	$1.4477 per kVa of Billing Demand	$0.0000 per kWh	0.4757¢ per kWh	0.0000¢ per kWh	
20	OLR	Optional Load Response Program Rider	Demand Response program for high voltage, high demand users.										Priced per customer
21	PIR	Phase-In Recovery Rider	Recovers costs associated with phase-in recovery bonds issued to securitize costs for which the Company was previously authorized recovery	Non-Bypassable	0.0176¢	0.0176¢	0.0176¢	0.0176¢	0.0176¢	0.0176¢	0.0176¢	0.0176¢	
22	PUR	PIPP Uncollectible Rider	Recovers uncollectible expense associated with PIPP customers to the extent such expense is incurred by the Company and is not recovered elsewhere. Charged for all kWhs per kWh	Non-Bypassable	0.0067¢	0.0067¢	0.0067¢	0.0067¢	0.0067¢	0.0067¢	0.0067¢	0.0067¢	
23	RAR	Reasonable Arrangement Rider	Recovery of the difference in revenue from the application of rates in the otherwise applicable rate schedule and this Rider shall be realized as part of the Company's Delta Revenue Recovery Rider and shall be subject to review by the PUCO	Non-Bypassable Recovered in DRR									
24	RDC	Residential Distribution Credit Rider	Applicable to any customer taking service under Rate Schedule RS who took service from the Company under one of the following rate schedules as of January 1, 2007, or any subsequent customer at that same service address, who continues to comply with the requirements of the previously applicable rate schedule set forth below, excluding customers who began service from the Company subsequent to April 30, 2009 who otherwise would qualify for service under this Rider on the basis of service identified as "Residential Water Heating" below: Residential Schedule (Solely under the Optional Load Management Rate), Residential Add-On Heat Pump, Residential Water Heating, Residential Space Heating, Residential Water Heating and Space Heating, Optional Electrically Heated Residential Apartment Schedule.	Is a rate. There is no true-up mechanism.	A customer's distribution charges as set forth in Rate Schedule RS shall be reduced by 1.77¢ per kWh for all kWhs in excess of 500 kWhs consumed by the customer during each winter billing period.								

Ohio Edison Company Riders - As of 11/31/2014

25	RER	Residential Electric Heating Recovery Rider	Recovers deferred purchased power costs which represent the differential between the amounts paid by customers that received or are receiving Rider RGC credits and the amounts that otherwise would have been paid by those customers but for the Commission's orders and entries in the 10-176-EL-ATA proceeding, including applicable interest	Non-Bypassable Recovered in EDR and RER	RER1:0.0000¢ RER2:0.5678¢								
26	RGC	Residential Generation Credit Rider	Applicable to any customer taking service under Rate Schedule RS who took service fro mthe Company under one of the following rate schedules as of January 1, 2007, or any subsequent customer at that same service address, who continues to comply with the requirements of the previously applicable rate schedule set forth below and who uses electricity as their primary or sole source of heat at that address: Residential Space Heating, Residential Optional Time-of-Day, Residential Optional Controlled Service Rider, Residential Load Management Rate, and Residential Optional Electrically Heated Residential Apartment Schedule. Credited for all kWhs in excess of 1,250kWhs, per kWh, consumed by the customer during each winter billing period.	Non-Bypassable Recovered in EDR and RER	(2.5900)¢								Additional Provision: Any customer receiving this credit as applicable above, and who takes electric generation service from a certified supplier, will have generation charges reduced by 1.90¢ per kWh for all kWhs in excess of 500 kWhs consumed during each winter billing period.
27	RTP	Experimental Real Time Pricing Rider	RTP Program is voluntary. Its purpose is to test customer response to hourly price signals quoted by PJM. Participation offers customers the opportunity to manage their electric costs by either shifting load from higher price to lower price periods or by adding new load during lower price periods			3.7387¢ 3.0497¢	3.2062¢ 2.5511¢	2.8963¢ 2.2677¢	2.7770¢ 2.1493¢				Customers also subject to $150 monthly Program Administrative Charge
28	SDC	School Distribution Credit Rider	Applicable to any public school district that is not taking service under the Company's Business Distribution Credit Rider and either was served under the Company's Energy for Education II program on 12/31/08 or is a new building in a school district that was served under Energy for Education II program on 12/31/08			The sum of distribution charges specified in Company's GS, GP, or GSU rates including all applicable riders shall be reduced by 8.693%							
29	SKT	State kWh Tax Rider	A state kWh tax shall be applied to each kWh delivered to a customer taking service under all rate schedules unless a customer elects to be a self-assessing purchaser that has been approved by the Ohio Department of Taxation.			First 2,000 kWhs 0.465¢ per kWh Next 13,000 kWhs 0.419¢ per kWh All Excess over 15,000 kWhs 0.363¢ per kWh							
30	USF	Universal Service Fund Rider	Exclusive purpose of providing funding for the low-income customer assistance programs and for the Consumer Education Program and paying for the administrative costs of both programs	Non-bypassable	A charge of 0.15843¢ per kWh for the first 833,000 kWh, and 0.10461¢ per kWh for the kWh above 833,000 kWh added to the energy charge of all applicable rate schedules								
31	DFC	Deferred Fuel Cost Recovery Rider	Reflects eligible fuel costs deferred from 1/06 thru 12/07, plus associated approved carrying costs on the unrecovered deferred cost balance.		0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	
32	DGC	Deferred Generation Cost Recovery Rider	Reflects recovery of generation costs deferred from June 2009 through May 2011 due to any future Commission Order plus the associated approved carrying costs on the unrecovered deferred cost balance. Also reflects recovery of Generation costs deferred from 1/09 thru 5/09 due to Commission Opinion and Order in Case No. 09-21-EL-ATA plus associated approved carrying costs on the unrecovered deferred cost balance.		0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	
33	DSI	Delivery Service Improvement Rider	Pays for distribution improvements.	Non-Bypassable	$0.0000	$0.0000	$0.0000	$0.0000					

***** *The shaded items need to be removed from OE's tariffs as they are no longer relevant.* *****

CLEVELAND ELECTRIC ILLUMINATING COMPANY RIDERS

#	Rider	Rider Name	Definition	Applicability	Rate Schedule RS	GS	GP	GSU	GT	STL	TRF	POL	Other
1	AER	Alternative Energy Resource Rider	The costs initially deferred by the Company and subsequently fully recovered through this Rider will be all costs associated with securing compliance with the alternative energy resource requirements including, but not limited to, all Renewable Energy Credits costs, any reasonable costs of administering the request for proposal, and applicable carrying costs. This rider is charged (for all rate classes) for all kWhs per kWh.	Bypassable	0.1732¢	0.1732¢	0.1672¢	0.1625¢	0.1623¢	0.1732¢	0.1732¢	0.1732¢	
2	AMI	Advanced Metering Infrastructure/ Modern Grid Rider	Cost recovery for Advanced Meter Installation. Not applicable to GT rate schedule. Charged to customers under all rate schedules (except STL) on a per customer, per bill basis. STL customers are charged per lighting unit, per month	Non-Bypassable	$0.2070	$1.0670	$15.0040	$17.0840	n/a	$0.0460	$0.2050	$0.2780	
3	BDC	Business Distribution Credit Rider	Applicable to any customer taking service under Rate Schedules GS or GP who on 4/30/09 took service under one of the following rate schedules and has not had a change of service address or a change to qualifying conditions subsequent to 4/30/09. Qualifying conditions are those in effect in the below rate schedules as they existed on 4/30/09 and continues to comply with the requirements of the previously applicable rate schedule set forth below: Electric Space Conditioning, All Electric Large General Service, Optional Electric Process Heating and Electric Boiler Load Management			Distribution charges shall be reduced by 1.50¢ per kWh for all kWhs consumed during winter billing periods	Distribution charges shall be reduced by 0.50¢ per kWh for all kWhs consumed during winter billing periods.						
4	CDR	CEI Delta Revenue Recovery Rider	Recovers the difference in revenue from the application of rates in the otherwise applicable rate schedule and the application of any special contract entered into prior to 1/1/09 and that continues in effect in 2009. Applies for all kWhs per kWh	Non-Bypassable				(0.0110)¢					
5	CPP	Experimental Critical Peak Pricing	Voluntary experimental program, applied in lieu of the GEN Rider. Reflects time-of-day pricing, for all kWh per kWh for both summer and winter seasons			Capacity: 1.3452¢ Energy:6.8428¢ Capacity: 1.3452¢ Energy:6.8428¢ Capacity: 1.3452¢ Energy:4.0818¢ Capacity: 1.3452¢ Energy:6.0134¢ Capacity: 1.3452¢ Energy:6.8751¢ Capacity: 1.3452¢ Energy:3.8747¢	Capacity:1.0158¢ Energy:6.6100¢ Capacity:1.0158¢ Energy:6.6100¢ Capacity:1.0158¢ Energy:3.9430¢ Capacity:1.0158¢ Energy:5.8098¢ Capacity:1.0158¢ Energy:6.6422¢ Capacity:1.0158¢ Energy:3.7435¢	Capacity:0.9791¢ Energy:6.4281¢ Capacity:0.9791¢ Energy:6.4281¢ Capacity:0.9791¢ Energy:3.8344¢ Capacity:0.9791¢ Energy:5.6505¢ Capacity:0.9791¢ Energy:6.4601¢ Capacity:0.9791¢ Energy:3.6409¢	Capacity:0.8319¢ Energy:6.4218¢ Capacity:0.8319¢ Energy:6.4218¢ Capacity:0.8319¢ Energy:3.8307¢ Capacity:0.8319¢ Energy:5.6450¢ Capacity:0.8319¢ Energy:6.4538¢ Capacity:0.8319¢ Energy:3.6373¢				There is a Program Administrative Charge of $37.50 per month. With day-ahead notification, the applicable Midday-Peak CPP Charge shall change to 32.0667¢ per kWh during the summer as determined by the Company.
6	DCR	Delivery Capital Recovery Rider	Recovers the costs associated with delivery plant investments made since the date certain in Case No. 07-551-EL-AIR, exclusive of any delivery plant investments being recovered elsewhere.	Non-Bypassable	0.5770¢ per kWh	$2.5731 per kW of Billing Demand	$0.9604 per kW of Billing Demand	$0.6652 per kW of Billing Demand					
7	DRR	Delta Revenue Recovery Rider	Recovers the difference in revenue between the application of rates in the otherwise applicable rate schedule and the result of any economic development schedule, energy efficiency schedule, reasonable arrangement, or governmental special contract approved by the PUCO on or after 1/1/09. Charged for all kWhs per kWh	Non-Bypassable	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
8	DSE	Demand Side Management and Energy Efficiency Rider	Provides recovery for FE's EEPDR programs. Mercantile customers who enter EEPDR programs with FE are exempted from this rider.	Non-bypassable	0.0450¢ 0.3962¢	0.0450¢ 0.2319¢	0.0450¢ 0.1258¢	0.0450¢ 0.1517¢	0.0450¢ 0.0396¢	0.0450¢ 0.0541¢	0.0450¢ 1.2354¢	0.0450¢ 0.0000¢	
9	DSM	Demand Side Management Rider	Applied to each kWh delivered during a billing month to all retail customers taking service under Rate Schedule RS	Non-Bypassable	$0.0000								
10	DUN	Dustribution Uncollectible Rider	Charged for all kWhs per kWh	Non-Bypassable	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
11	EDR	Economic Development Rider	a. Residential Non-Standard Credit Provision- applicable to residential customers to which RDC Rider applies. Applied for all kWhs per kWh in excess of 500 kWhs per month, during winter billing periods	Non-bypassable	(1.9000)¢ (1.9000)¢ (0.5000)¢ (1.9000)¢ (1.9000)¢ (1.9000)¢								
			b. Interruptible Credit Provision- applicable to customers under PUCO-approved contracts containing interruptible provisions, in conjunction with ELR Rider, applied by unit of Curtailable Load as defined in Rider ELR (per kW)				($5.0000)	($5.0000)	($5.0000)				
			c. Non-Residential Credit Provision- for all kWhs per kWh d. General Service- Transmission Provision						(0.0000)¢ $8.0000 (1.7706)¢	(0.0000)¢	(2.9207)¢	(0.0000)¢	

Cleveland Electric IlluminatingRiders - As of 11/31/2014

			e. Standard Charge Provision- recover the difference in revenues resulting from the application of rates in the otherwise applicable rate schedule and the application of credits in a, b, c and f of this rider				0.1690¢	0.2994¢					
			f. School Credit Provision- Credit applicable to public school				All Rider GEN charges for these rate classes shall be reduced by 8.693%						
			g. Infrastructure Improvement Provision- Recovers costs associated with certain economic expansion and new employment in Ohio		0.0478¢	0.0327¢	0.0120¢	0.0048¢	0.0015¢				
			h. Automaker Credit Provision- only applied to usage that exceeds baseline usage										(1.0000)¢ (1.2000)¢
			i. Automaker Charge Provision- Recover costs associated with implementation of the Automaker Credit Provision			0.0068¢							
12	ELR	Economic Load Response Program Rider	Demand Response program for high voltage, high demand users.										Priced per customer
13	FUEL	Fuel Rider	The Fuel Rider charge shall be reconciled to reflect the difference between actual and forecasted costs and the difference between actual and forecasted generation revenue and revenue collected under this Rider.	Bypassable	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
14	GCR	Generation Cost Reconciliation Rider	Charged for all kWhs per kWh. For any given billing period, only the non-zero GCR charge will be applied.		0.3720¢ $0.0000	0.3720¢ $0.0000	0.3591¢ $0.0000	0.3490¢ $0.0000	0.3486¢ $0.0000	0.3720¢ $0.0000	0.3720¢ $0.0000	0.3720¢ $0.0000	
15	GEN	Generation Service Rider	For customers taking the SSO Generation Service from the Company. Charged for all kWhs per kWh unless otherwise noted.		Capacity:1.1223¢ Energy:6.0922¢ Capacity:1.1223¢ Energy:5.1165¢	Capacity:1.3452¢ Energy:6.0922¢ Capacity:1.3452¢ Energy:5.1165¢ Capacity:1.3452¢ Energy:10.7235¢ Capacity:1.3452¢ Energy:6.8428¢ Capacity:1.3452¢ Energy:4.0818¢ Capacity:1.3452¢ Energy:6.0134¢ Capacity:1.3452¢ Energy:6.8751¢ Capacity:1.3452¢ Energy:3.8747¢	Capacity:1.0158¢ Energy:5.8850¢ Capacity:1.0158¢ Energy:4.9432¢ Capacity:1.0158¢ Energy:10.3588¢ Capacity:1.0158¢ Energy:6.6100¢ Capacity:1.0158¢ Energy:3.9430¢ Capacity:1.0158¢ Energy:5.8098¢ Capacity:1.0158¢ Energy:6.6422¢ Capacity:1.0158¢ Energy:3.7435¢	Capacity:0.9791¢ Energy:5.7230¢ Capacity:0.9791¢ Energy:4.8077¢ Capacity:0.9791¢ Energy:10.0737¢ Capacity:0.9791¢ Energy:6.4281¢ Capacity:0.9791¢ Energy:3.8344¢ Capacity:0.9791¢ Energy:5.6505¢ Capacity:0.9791¢ Energy:6.4601¢ Capacity:0.9791¢ Energy:3.6409¢	Capacity:0.8319¢ Energy:5.7174¢ Capacity:0.8319¢ Energy:4.8030¢ Capacity:0.8319¢ Energy:10.0638¢ Capacity:0.8319¢ Energy:6.4218¢ Capacity:0.8319¢ Energy:3.8307¢ Capacity:0.8319¢ Energy:5.6450¢ Capacity:0.8319¢ Energy:6.4538¢ Capacity:0.8319¢ Energy:3.6373¢	Capacity:0.0000¢ Energy:6.0922¢ Capacity:0.0000¢ Energy:5.1165¢	Capacity:0.2489¢ Energy:6.0922¢ Capacity:0.2489¢ Energy:5.1165¢	Capacity:0.0000¢ Energy:6.0922¢ Capacity:0.0000¢ Energy:5.1165¢	
16	HNM	Hospital Net Metering Rider	Available to qualifying hospitals having self-generation equipment located on the Hospital's premises that operates in parallel with the Company's facilities.										Hospital shall be charged for all electricity used in accordance with the rate schedule for which the Hospital would otherwise qualify. All electricity generated by the Hospital shall be credited on an hourly basis for the time the Hospital's electricity is generated, at the locational marginal price of energy quoted by the applicable RTO.
17	LEX	Line Extension Cost Recovery Rider	Charged for all kWhs per kWh	Non-Bypassable	0.0006¢	0.0006¢	0.0006¢	0.0006¢	0.0006¢	0.0006¢	0.0006¢	0.0006¢	
18	NDU	Non-Distribution Uncollectible Rider	Charged for all kWhs per kWh	Bypassable	0.0700¢	0.0700¢	0.0700¢	0.0700¢	0.0700¢	0.0700¢	0.0700¢	0.0700¢	
19		Net Energy Metering Rider	Customer-generator facility must use as its fuel either solar, wind, biomass, landfill gas, or hydropower, or use a microturbine or a fuel cell located on the customer-generator's premises and is intended primarily to offset part or all of the customer's electricity requirements.		The provisions of this rider will be applied to the rate schedule to which the customer would be assigned if that customer were not a customer-generator. The customer-generator will be billed or credited charges and applicable riders as measure by the meter.								
20	NMB	Non-Market-Based Services Rider	Recovers non-market-based costs, fees, or charges imposed on or charged to the Company by FERC or a regional transmission organization, independent transmission operator, or similar organization approved by FERC. This Rider may be updated: 1) to account for changes in existing non-market-based costs, fees or charges and 2) to include any non-market-based costs, fees or charges that were not yet in effect on the effective date of this Rider and/or otherwise imposed on or charged to the Company by FERC or RTO.	Non-Bypassable	0.4030¢ per kWh	$1.4399 per kW of Billing Demand	$1.9045 per kW of Billing Demand	$1.6927 per kW of Billing Demand	$1.4879 per kVa of Billing Demand	$0.0000 per kWh	0.0942¢ per kWh	0.0000¢ per kWh	
21	OLR	Optional Load Response Program Rider	Demand Response program for high voltage, high demand users.										Priced per customer

Cleveland Electric IlluminatingRiders - As of 11/31/2014

22	PIR	Phase-In Recovery Rider	Recovers costs associated with phase-in recovery bonds issued to securitize costs for which the Company was previously authorized recovery	Non-Bypassable	0.1327¢	0.1327¢	GP1=0.1291¢ GP2=0.0302¢	GSU1=0.1264¢ GSU2=0.0302¢	GT1=0.1262¢ GT2=0.0302¢	0.1327¢	0.1327¢	0.1327¢	
23	PTR	Peak Time Rebate Rider	Only available to customers taking service at locations within the particular geographic area identified in FE's Smart Grid Modernization Initiative, who are not taking service under CPP or RTP. Participants will be assigned a Critical Peak Period, and during the months of June through August, the Company will call up to 15 CPE's each year.		Rebate amount of $0.40 per kWh reduced during CPE								
24	PUR	PIPP Uncollectible Rider	Recovers uncollectible expense associated with PIPP customers to the extent such expense is incurred by the Company and is not recovered elsewhere. Charged for all kWhs per kWh	Non-Bypassable	0.0074¢	0.0074¢	0.0074¢	0.0074¢	0.0074¢	0.0074¢	0.0074¢	0.0074¢	
25	RAR	Reasonable Arrangement Rider	Recovery of the difference in revenue from the application of rates in the otherwise applicable rate schedule and this Rider shall be realized as part of the Company's Delta Revenue Recovery Rider and shall be subject to review by the PUCO	Non-bypassable. Recovered in DRR									
26	RCP	Residential Critical Peak Pricing Rider	Only available to customers taking service at locations within the particular geographic area identified in FE's Smart Grid Modernization Initiative, who are not taking generation service from a certified supplier or during the period the customer is taking service under PTR. Applied in lieu of GEN Rider		Off-Peak 3.9570¢ On-Peak 7.1321¢ Critical Peak 34.1326¢ Capacity Charges 1.1223¢ Energy Charges 5.1165¢								
27	RDC	Residential Distribution Credit Rider	Applicable to any customer taking service under Rate Schedule RS who took service from the Company under one of the following rate schedules as of January 1, 2007, or any subsequent customer at that same service address, who continues to comply with the requirements of the previously applicable rate schedule set forth below, excluding customers who began service from the Company subsequent to April 30, 2009 who otherwise would qualify for service under this Rider on the basis of service identified as "Residential Water Heating" below: Residential Schedule (Solely under the Optional Load Management Rate), Residential Add-On Heat Pump, Residential Water Heating, Residential Space Heating, Residential Water Heating and Space Heating, Optional Electrically Heated Residential Apartment Schedule.	This is a rate with no true-up mechanism.	A customer's distribution charges as set forth in Rate Schedule RS shall be reduced by 1.70¢ per kWh for all kWhs in excess of 500 kWhs consumed by the customer during each winter billing period.								
28	RER	Residential Electric Heating Recovery Rider	Recovers deferred purchased power costs which represent the differential between the amounts paid by customers that received or are receiving Rider RGC credits and the amounts that otherwise would have been paid by those customers but for the Commission's orders and entries in the 10-176-EL-ATA proceeding, including applicable interest	Non-Bypassable. Is recovered in the EDR and RER.	RER1:0.0000¢ RER2:0.3161¢								
29	RGC	Residential Generation Credit Rider	Applicable to any customer taking service under Rate Schedule RS who took service fro mthe Company under one of the following rate schedules as of January 1, 2007, or any subsequent customer at that same service address, who continues to comply with the requirements of the previously applicable rate schedule set forth below and who uses electricity as their primary or sole source of heat at that address: Residential Schedule (Solely under the Optional Load Management Rate), Residential Add-On Heat Pump, Residential Space Heating, Residential Water Heating and Space Heating, Optional Electrically Heated Residential Apartment Schedule. Credited for all kWhs per kWh consumed by the customer during each winter billing period.	Non-Bypassable. Is recovered in the EDR and RER	(2.1000)¢								Additional Provision: Any customer receiving this credit as applicable above, and who takes electric generation service from a certified supplier, will have generation charges reduced by 1.90¢ per kWh for all kWhs in excess of 500 kWhs consumed during each winter billing period.
30	RTP	Experimental Real Time Pricing Rider	RTP Program is voluntary. Its purpose is to test customer response to hourly price signals quoted by PJM. Participation offers customers the opportunity to manage their electric costs by either shifting load from higher price to lower price periods or by adding new load during lower price periods			3.7214¢ 3.0324¢	3.1848¢ 2.5297¢	2.9861¢ 2.3575¢	2.8333¢ 2.2056¢				
31	SDC	School Distribution Credit Rider	Applicable to any public school district that is not taking service under the Company's Business Distribution Credit Rider and either was served under the Company's Energy for Education II program on 12/31/08 or is a Cleveland Municipal School District building that was served by the Company on 1/21/09			The sum of distribution charges specified in Company's GS, GP, or GSU rates including all applicable riders shall be reduced by 8.693%							
32	SKT	State kWh Tax Rider	A state kWh tax shall be applied to each kWh delivered to a customer taking service under all rate schedules unless a customer elects to be a self-assessing purchaser that has been approved by the Ohio Department of Taxation.			First 2,000 kWhs 0.465¢ per kWh Next 13,000 kWhs 0.419¢ per kWh All Excess over 15,000 kWhs 0.363¢ per kWh							
33	USF	Universal Service Fund Rider	Exclusive purpose of providing funding for the low-income customer assistance programs and for the Consumer Education Program and paying for the administrative costs of both programs		A charge of 0.16007¢ per kWh for the first 833,000 kWh, and 0.05680¢ per kWh for the kWh above 833,000 kWh added to the energy charge of all applicable rate schedules								
34	DFC	Deferred Fuel Cost Recovery Rider	Reflects eligible fuel costs deferred from 1/06 thru 12/07, plus associated approved carrying costs on the unrecovered deferred cost balance.		0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	

35	DGC	Deferred Generation Cost Recovery Rider	Reflects recovery of generation costs deferred from June 2009 through May 2011 due to any future Commission Order plus the associated approved carrying costs on the unrecovered deferred cost balance. Also reflects recovery of Generation costs deferred from 1/09 thru 5/09 due to Commission Opinion and Order in Case No. 09-21-EL-ATA plus associated approved carrying costs on the unrecovered deferred cost balance.`		0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	
36	DSI	Delivery Service Improvement Rider	Pays for distribution improvements.	Non-Bypassable	$0.0000	$0.0000	$0.0000	$0.0000					
37	GRC	Grandfathered Contract Riders	Applicable only to customer facilities taking service under a special contract entered into with the Company prior to 1/1/2001.										EFC rate is 1.3918¢ per kWh. The tariff rate's generation charge shall be reduced by the fuel portion charge equivalent to the applicable EFC rider charge. Customer's either elect to pay a $.30 per month per meter charge associated with the metering equipment necessary to effectively implement that off-peak option, or has metering equipment to determine off-peak demand measurement First 2,000 kWh $0.00465 per kWh Next 13,000 kWh$0.00419 per kWh All Excess Over 15,000 kWh $0.00363 per kWh Credit shall equal the Statutory kWh Tax.

****** *The shaded items need to be removed from CEI's tariffs as they are no longer relevant.*******

TOLEDO EDISON COMPANY RIDERS

#	Rider	Rider Name	Definition	Applicability	Rate Schedule								Other
					RS	GS	GP	GSU	GT	STL	TRF	POL	
1	AER	Alternative Energy Resource Rider	The costs initially deferred by the Company and subsequently fully recovered through this Rider will be all costs associated with securing compliance with the alternative energy resource requirements including, but not limited to, all Renewable Energy Credits costs, any reasonable costs of administering the request for proposal, and applicable carrying costs. This rider is charged (for all rate classes) for all kWhs per kWh.	Bypassable	0.1027¢	0.1027¢	0.0991¢	0.0964¢	0.0963¢	0.1027¢	0.1027¢	0.1027¢	
2	AMI	Advanced Metering Infrastructure/ Modern Grid Rider	Cost recovery for Advanced Meter Installation. Not applicable to GT rate schedule. Charged to customers under all rate schedules (except STL) on a per customer, per bill basis. STL customers are charged per lighting unit, per month	Non-Bypassable	$0.2070	$1.0670	$15.0040	$17.0840	n/a	$0.0460	$0.2050	$0.2780	
3	BDC	Business Distribution Credit Rider	Applicable to any customer taking service under Rate Schedules GS or GP who on 4/30/09 took service under one of the following rate schedules and has not had a change of service address or a change to qualifying conditions subsequent to 4/30/09. Qualifying conditions are those in effect in the below rate schedules as they existed on 4/30/09 and continues to comply with the requirements of the previously applicable rate schedule set forth below: Electric Space Conditioning, All Electric Large General Service, Optional Electric Process Heating and Electric Boiler Load Management			Distribution charges shall be reduced by 1.5000¢ per kWh for all kWhs consumed during winter billing periods	Distribution charges shall be reduced by 0.5000¢ per kWh for all kWhs consumed during winter billing periods.						
4	CPP	Experimental Critical Peak Pricing	Voluntary experimental program, applied in lieu of the GEN Rider. Reflects time-of-day pricing, for all kWh per kWh for both summer and winter seasons			Capacity: 1.3684¢ Energy:6.8428¢ Capacity: 1.3684¢ Energy:6.8428¢ Capacity: 1.3684¢ Energy:4.0818¢ Capacity: 1.3684¢ Energy:6.0134¢ Capacity: 1.3684¢ Energy:6.8751¢ Capacity: 1.3684¢ Energy:3.8747¢	Capacity:1.1155¢ Energy:6.6100¢ Capacity:1.1155¢ Energy:6.6100¢ Capacity:1.1155¢ Energy:3.9430¢ Capacity:1.1155¢ Energy:5.8098¢ Capacity:1.1155¢ Energy:6.6422¢ Capacity:1.1155¢ Energy:3.7435¢	Capacity:0.9749¢ Energy:6.4281¢ Capacity:0.9749¢ Energy:6.4281¢ Capacity:0.9749¢ Energy:3.8344¢ Capacity:0.9749¢ Energy:5.6505¢ Capacity:0.9749¢ Energy:6.4601¢ Capacity:0.9749¢ Energy:3.6409¢	Capacity:0.8066¢ Energy:6.4218¢ Capacity:0.8066¢ Energy:6.4218¢ Capacity:0.8066¢ Energy:3.8307¢ Capacity:0.8066¢ Energy:5.6450¢ Capacity:0.8066¢ Energy:6.4538¢ Capacity:0.8066¢ Energy:3.6373¢				There is a Program Administrative Charge of $37.50 per month. With day-ahead notification, the applicable Midday-Peak CPP Charge shall change to 32.0667¢ per kWh during the summer as determined by the Company.
5	DCR	Delivery Capital Recovery Rider	Recovers the costs associated with delivery plant investments made since the date certain in Case No. 07-551-EL-AIR, exclusive of any delivery plant investments being recovered elsewhere.	Non-Bypassable	0.4858¢ per kWh	$1.7736 per kW of Billing Demand	$0.7226 per kW of Billing Demand	$0.1931 per kW of Billing Demand					
6	DRR	Delta Revenue Recovery Rider	Recovers the difference in revenue between the application of rates in the otherwise applicable rate schedule and the result of any economic development schedule, energy efficiency schedule, reasonable arrangement, or governmental special contract approved by the PUCO on or after 1/1/09. Charged for all kWhs per kWh	Non-Bypassable	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
7	DSE	Demand Side Management and Energy Efficiency Rider	Provides recovery for FE's EEPDR programs. Mercantile customers who enter EEPDR programs with FE are exempted from this rider.	Non-bypassable	0.0450¢ 0.1440¢	0.0450¢ 0.2734¢	0.0450¢ 0.2713¢	0.0450¢ (0.2589)¢	0.0450¢ 0.2151¢	0.0450¢ 0.0291¢	0.0450¢ 0.1072¢	0.0450¢ 0.0000¢	
8	DSM	Demand Side Management Rider	Applied to each kWh delivered during a billing month to all retail customers taking service under Rate Schedule RS	Non-Bypassable	$0.0000								

9	DUN	Distribution Uncollectible Rider	Charged for all kWhs per kWh	Non-Bypassable					0.0012¢				
10	EDR	Economic Development Rider	a. Residential Non-Standard Credit Provision- applicable to residential customers to which RDC Rider applies. Applied for all kWhs per kWh in excess of 500 kWhs per month, during winter billling periods	Non-bypassable	(1.9000)¢ (1.9000)¢ (0.5000)¢ (1.9000)¢ (1.9000)¢								
			b. Interruptible Credit Provision- applicable to customers under PUCO-approved contracts containing interruptible provisions, in conjunction with ELR Rider, applied by unit of Curtailable Load as defined in Rider ELR (per kW)				($5.0000)	($5.0000)	($5.0000)				
			c. Non-Residential Credit Provision- for all kWhs per kWh						(0.0000)¢	(0.0000)¢	(0.7235)¢	(0.0000)¢	
			d. General Service- Transmission Provision						$8.0000 (1.7706)¢				
			e. Standard Charge Provision- recover the difference in revenues resulting from the application of rates in the otherwise applicable rate schedule and the application of credits in a, b, c and f of this rider				0.0871¢	0.3797¢					
			f. School Credit Provision- Credit applicable to public school					All Rider GEN charges for these rate classes shall be reduced by 8.693%					
			g. Infrastructure Improvement Provision- Recovers costs associated with certain economic expansion and new employment in Ohio		0.0478¢	0.0327¢	0.0120¢	0.0048¢	0.0015¢				
			h. Automaker Credit Provision- only applied to usage that exceeds baseline usage										(1.0000)¢ (1.2000)¢
			i. Automaker Charge Provision- Recover costs associated with implementation of the Automaker Credit Provision				0.0068¢						
11	ELR	Economic Load Response Program Rider	Demand Response program for high voltage, high demand users.										Priced per customer
12	FUEL	Fuel Rider	The Fuel Rider charge shall be reconciled to reflect the difference between actual and forecasted costs and the difference between actual and forecasted generation revenue and revenue collected under this Rider.	Bypassable	0.1058¢	0.1058¢	0.1022¢	0.0993¢	0.0992¢	0.1058¢	0.1058¢	0.1058¢	
13	GCR	Generation Cost Reconciliation Rider	Charged for all kWhs per kWh. For any given billing period, only the non-zero GCR charge will be applied.		0.3720¢ $0.0000	0.3720¢ $0.0000	0.3591¢ $0.0000	0.3490¢ $0.0000	0.3486¢ $0.0000	0.3720¢ $0.0000	0.3720¢ $0.0000	0.3720¢ $0.0000	
14	GEN	Generation Service Rider	For customers taking the SSO Generation Service from the Company. Charged for all kWhs per kWh unless otherwise noted.		Capacity:1.1425¢ Energy:6.0922¢ Capacity:1.1425¢ Energy:5.1165¢	Capacity:1.3684¢ Energy:6.0922¢ Capacity:1.3684¢ Energy:5.1165¢ Capacity:1.3684¢ Energy:10.7235¢ Capacity:1.3684¢ Energy:6.8428¢ Capacity:1.3684¢ Energy:4.0818¢ Capacity:1.3684¢ Energy:6.0134¢ Capacity:1.3684¢ Energy:6.8751¢ Capacity:1.3684¢ Energy:3.8747¢	Capacity:1.1155¢ Energy:5.8850¢ Capacity:1.1155¢ Energy:4.9432¢ Capacity:1.1155¢ Energy:10.3588¢ Capacity:1.1155¢ Energy:6.6100¢ Capacity:1.1155¢ Energy:3.9430¢ Capacity:1.1155¢ Energy:5.8098¢ Capacity:1.1155¢ Energy:6.6422¢ Capacity:1.1155¢ Energy:3.7435¢	Capacity:0.9749¢ Energy:5.7230¢ Capacity:0.9749¢ Energy:4.8077¢ Capacity:0.9749¢ Energy:10.0737¢ Capacity:0.9749¢ Energy:6.4281¢ Capacity:0.9749¢ Energy:3.8344¢ Capacity:0.9749¢ Energy:5.6505¢ Capacity:0.9749¢ Energy:6.4601¢ Capacity:0.9749¢ Energy:3.6409¢	Capacity:0.8066¢ Energy:5.7174¢ Capacity:0.8066¢ Energy:4.8030¢ Capacity:0.8066¢ Energy:10.0638¢ Capacity:0.8066¢ Energy:6.4218¢ Capacity:0.8066¢ Energy:3.8307¢ Capacity:0.8066¢ Energy:5.6450¢ Capacity:0.8066¢ Energy:6.4538¢ Capacity:0.8066¢ Energy:3.6373¢	Capacity:0.0000¢ Energy:6.0922¢ Capacity:0.0000¢ Energy:5.1165¢	Capacity:0.5269¢ Energy:6.0922¢ Capacity:0.5269¢ Energy:5.1165¢	Capacity:0.0000¢ Energy:6.0922¢ Capacity:0.0000¢ Energy:5.1165¢	

15	HNM	Hospital Net Metering Rider	Available to qualifying hospitals having self-generation equipment located on the Hospital's premises that operates in parallel with the Company's facilities.										Hospital shall be charged for all electricity used in accordance with the rate schedule for which the Hospital would otherwise qualify. All electricity generated by the Hospital shall be credited on an hourly basis for the time the Hospital's electricity is generated, at the locational marginal price of energy quoted by the applicable RTO.
16	LEX	Line Extension Cost Recovery Rider	Charged for all kWhs per kWh	Non-Bypassable				0.0009¢					
17	NDU	Non-Distribution Uncollectible Rider	Charged for all kWhs per kWh	Bypassable				0.0872¢					
18		Net Energy Metering Rider	Customer-generator facility must use as its fuel either solar, wind, biomass, landfill gas, or hydropower, or use a microturbine or a fuel cell located on the customer-generator's premises and is intended primarily to offset part or all of the customer's electricity requirements.		The provisions of this rider will be applied to the rate schedule to which the customer would be assigned if that customer were not a customer-generator. The customer-generator will be billed or credited charges and applicable riders as measure by the meter.								
19	NMB	Non-Market-Based Services Rider	Recovers non-market-based costs, fees, or charges imposed on or charged to the Company by FERC or a regional transmission organization, independent transmission operator, or similar organization approved by FERC. This Rider may be updated: 1) to account for changes in existing non-market-based costs, fees or charges and 2) to include any non-market-based costs, fees or charges that were not yet in effect on the effective date of this Rider and/or otherwise imposed on or charged to the Company by FERC or RTO.	Non-Bypassable	0.4508¢ per kWh	$1.4455 per kW of Billing Demand	$1.6994 per kW of Billing Demand	$1.9093 per kW of Billing Demand	$2.1950 per kVa of Billing Demand	$0.0000 per kWh	0.2060¢ per kWh	0.0000¢ per kWh	
20	OLR	Optional Load Response Program Rider	Demand Response program for high voltage, high demand users.										Priced per customer
21	PIR	Phase-In Recovery Rider	Recovers costs associated with phase-in recovery bonds issued to securitize costs for which the Company was previously authorized recovery	Non-Bypassable	0.0276¢	0.0276¢	0.0276¢	0.0276¢	0.0276¢	0.0276¢	0.0276¢	0.0276¢	
22	PUR	PIPP Uncollectible Rider	Recovers uncollectible expense associated with PIPP customers to the extent such expense is incurrec by the Company and is not recovered elsewhere. Charged for all kWhs per kWh	Non-Bypassable	0.0069¢	0.0069¢	0.0069¢	0.0069¢	0.0069¢	0.0069¢	0.0069¢	0.0069¢	
23	RAR	Reasonable Arrangement Rider	Recovery of the difference in revenue from the application of rates in the otherwise applicable rate schedule and this Rider shall be realized as part of the Company's Delta Revenue Recovery Rider and shall be subject to review by the PUCO	Non-Bypassable Recovered in DRR									

Toledo Edison Company Riders - As of 11/31/2014

24	RDC	Residential Distribution Credit Rider	Applicable to any customer taking service under Rate Schedule RS who took service from the Company under one of the following rate schedules as of January 1, 2007, or any subsequent customer at that same service address, who continues to comply with the requirements of the previously applicable rate schedule set forth below, excluding customers who began service from the Company subsequent to April 30, 2009 who otherwise would qualify for service under this Rider on the basis of service identified as "Residential Water Heating" below: Residential Add-On Heat Pump, Residential Water Heating, Residential Space Heating, Residential Water Heating and Space Heating, Residential Apartment Rate.	This is a rate. There is no true-up mechanism.	A customer's distribution charges as set forth in Rate Schedule RS shall be reduced by 1.76¢ per kWh for all kWhs in excess of 500 kWhs consumed by the customer during each winter billing period.								
25	RER	Residential Electric Heating Recovery Rider	Recovers deferred purchased power costs which represent the differential between the amounts paid by customers that received or are receiving Rider RGC credits and the amounts that otherwise would have been paid by those customers but for the Commission's orders and entries in the 10-176-EL-ATA proceeding, including applicable interest	Non-Bypassable Recovered in EDR and RER	RER1:0.0000¢ RER2:0.2446¢								
26	RGC	Residential Generation Credit Rider	Applicable to any customer taking service under Rate Schedule RS who took service from the Company under one of the following rate schedules as of January 1, 2007, or any subsequent customer at that same service address, who continues to comply with the requirements of the previously applicable rate schedule set forth below and who uses electricity as their primary or sole source of heat at that address: Residential ADd-On Heat Pump, Residential Space Heating, Residential Space Heating and Water Heating, Residential Apartment Rate. RGC1 Will apply for all kWhs in excel of 2,000 kWhs, per kWh, RGC2 will apply for the first 2,000 kWhs, per kWh.	Non-bypassable. Recovered in EDR and RER	(1.4100)¢ (2.2300)¢								Additional Provision: Any customer receiving this credit as applicable above, and who takes electric generation service from a certified supplier, will have generation charges reduced by 1.90¢ per kWh for all kWhs in excess of 500 kWhs consumed during each winter billing period.
27	RTP	Experimental Real Time Pricing Rider	RTP Program is voluntary. Its purpose is to test customer response to hourly price signals quoted by PJM. Participation offers			3.7446¢ 3.0556¢	3.2845¢ 2.6294¢	2.9819¢ 2.3533¢	2.8080¢ 2.1803¢				Customers also subject to $150 monthly Program Administrative
28	SDC	School Distribution Credit Rider	Applicable to any public school district that is not taking service under the Company's Business Distribution Credit Rider and either was served under the Company's Energy for Education II program on 12/31/08 or is a new building in a school district that was served under Energy for Education II program on 12/31/08		The sum of distribution charges specified in Company's GS, GP, or GSU rates including all applicable riders shall be reduced by 8.693%								
29	SKT	State kWh Tax Rider	A state kWh tax shall be applied to each kWh delivered to a customer taking service under all rate schedules unless a customer elects to be a self-assessing purchaser that has been approved by the Ohio Department of Taxation.		First 2,000 kWhs 0.465¢ per kWh Next 13,000 kWhs 0.419¢ per kWh All Excess over 15,000 kWhs 0.363¢ per kWh								
30	USF	Universal Service Fund Rider	Exclusive purpose of providing funding for the low-income customer assistance programs and for the Consumer Education Program and paying for the administrative costs of both programs	Non-bypassable	A charge of 0.09692¢ per kWh for the first 833,000 kWh, and 0.05610¢ per kWh for the kWh above 833,000 kWh added to the energy charge of all applicable rate schedules								
31	DSI	Delivery Service Improvement Rider	Pays for distribution improvements.	Non-Bypassable	$0.0000	$0.0000	$0.0000	$0.0000					
32	DFC	Deferred Fuel Cost Recovery Rider	Reflects eligible fuel costs deferred from 1/06 thru 12/07, plus associated approved carrying costs on the unrecovered deferred cost balance.		0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	

Toledo Edis											
33	DGC	Deferred Generation Cost Recovery Rider	Reflects recovery of generation costs deferred from June 2009 through May 2011 due to any future Commission Order plus the associated approved carrying costs on the unrecovered deferred cost balance. Also reflects recovery of Generation costs deferred from 1/09 thru 5/09 due to Commission Opinion and Order in Case No. 09-21-EL-ATA plus associated approved carrying costs on the unrecovered deferred cost balance.`	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢	0.0000¢

******** The shaded items need to be removed from TE's tariffs as they are no longer relevant.********

N

DUKE ENERGY OHIO RIDERS

#	Rider	Rider Name	Definition	Rate Schedule Other	Applicability	RS
1	PTR	Peak Time Rebate Residential Pilot Program	Voluntary program that offers residential customers the opportunity to reduce electric costs by reducing their electric usage during critical peak load periods. No more than 500 customers may participate. Customers will receive a bill credit of $0.2800 per kWh of load reduction if they respond Company the day before.		Non-bypassable	$0.2800 per kWh
2	DR-IKE	Storm Recovery Rider	Allows the Company to recover costs incurred due to Hurricane Ike.		Non-bypassable	$0.00 per month
3	DIR	Development Incentive Rider	This rider is designed to encourage economic development or redevelopment in the Company's service territory. It consists of three parts: (1) The Economic Development Program (2) Urban Redevelopment Program (3) Brownfield Rdevelopment Program	Customer must meet requirements of applicable program(s). Customer must comply with all terms of the tariff rate associated with the service taken, except that the monthly distribution demand charge shall be reduced by up to fifty percent for a period of 24 months. No Rate Charged to Customers Under Rider DIR.	Terminates May '15 No customers No delta recovery	
4	USR	Universal Service Fund	Universal service fund established by Ohio Amended Substitute Senate Bill No. 3. Rider is applicable to all jurisdictional retail customers, including interdepartmental sales, in the Company's electric service area.	All kWh are subject to the Universal Service Fund Rider. The amount to be charged monthly beginning January 2, 2014 shall be as follows: First 833,000 kWh - $0.0010791 per kWh. All Additional kWh - $0.0004690 per kWh	Non-bypassable	
5	PLM	Peak Load Management	Program is voluntary and offers Customers the opportunity to reduce electric costs by managing their usage during peak load periods. Customers served under Standard Rates DS, DP and TS or Rate RTP may participate in one of 3 options offered under the program: (a) reduce demand to a specified amount (b) reduce energy usage below their baseline (c) sell the output of any Customer-owned self generation to Company.	Option (a) Customer agrees to limit their demand to a Firm Load Level. Company will establish a bill credit, and will provide buy-through energy, if available, to be billed based on price quotes. Customers will be billed for all usage above the Firm Load Level at such buy-through quotes. If buy-through is not available and customer does not reduce usage, Customer will be billed for all usage above the Firm Load Level at $10.00 per kWh. Option (b) Customer agrees to reduce energy usage below their Baseline Level. Reductions below the Baseline Level during such periods will be credited at the Energy Buy-Back Price Quotes provided to the Customer by the Company.		

#	Rider	Rider Name	Definition	Rate Schedule Other	Applicability	RS
				Option © Customer agrees upon notification by the Company to sell the output of their electric generator to the Company. Customer and Company will mutually agree on the amount of generation to be sold back and the conditions under which a request to run the generator can be issued. Company will establish a bill credit to be given to the customer.		
6	UE-GEN	Uncollectible Expense Electric Generation	This rider enables the recovery of uncollectible accounts expense related to generation service including Percentage of Income Payment (PIPP) customer installments not collected through the Universal Service Fund Rider.	Residential Customers: A charge of $0.000184 per kWh shall be applied to all kWh delivered. Non-Residential Customers: A charge of ($0.07) per bill shall be applied to each non-residential customer.	Non-bypassable	
7	BTR	Base Transmission Rider	Allows for recovery of the cost to provide retail transmission service.		Non-bypassable	$0.004826 per kWh\kW
8	DR-IM	Infrastructure Modernization	Recovers costs associated with investments to Duke's distribution system including automation measures.		Non-bypassable	$4.83 per month
9	DR-ECF	Economic Competitiveness Fund	Economic development rider.	Applicable to all retail jurisdictional customers. $0.000312 per kWh	Non-bypassable	

#	Rider	Rider Name	Definition	Rate Schedule Other	Applicability	RS
10	**DR-SAW & SAW-R**	Energy Efficiency Cost Recovery	Allows Duke to recover costs of its EE programs. Mercantile customers who enter EE programs are exempted from this rider.	Applicable to service rendered under the provisions of Rates RS, ORH, TD-AM, TD, RS3P, RSLI, TD-CPP_LITE, and TD-LITE (residential class) and Rates DS, DM, DP, TS, EH, GS-FL, SFL-ADPL, RTP and CUR (non-residential class). The monthly amount computed under each of the rate schedules to which this rider is applicable shall be increased or decreased by the energy DR-SAW Charge at a rate per kWh of monthly consumption and, where applicable, a rate per kW of monthly billing demand. Refer to tariff for formulas used to determine rates.	Non-bypassable	
11	**UE-ED**	Uncollectible Expense Electric Distribution	This rider enables the recovery of incremental uncollectible accounts expense above what is recovered in base rates and includes Percentage of Income Payment (PIPP) customer installments not collected through the Universal Service Fund Rider.	A charge of $0.000136 per kWh shall be applied to all kWh delivered to residential customers. A charge of ($0.18) per bill shall be applied to each non-residential customer.	Non-bypassable	
12	AER-R	Alternative Energy Recovery	This rider enables the recovery of all the Company's cost for complying with Ohio's renewable energy requirements under Section 4928.64 of Ohio Revised Code, including the acquisition costs of renewable energy credits.	A charge of $0.000364 per kWh shall be applied to all kWh delivered to all applicable customers.	Bypassable	
13	**RC**	Retail Capacity	Establishes market based capacity charges. For the term of the Electric Security plan approved in Case No. 11-3549-EL-SSO, Rider RC rates will be calculated based on the wholesale Final Zone Capacity Price (FZCP) associated with the annual auctions conducted by PJM Interconnection, LLC.	All rates are per kWh/kW	Bypassable	Summer, 1st 1000 kWh $0.013000 Summer, Addt'l kWh $0.017273 Winter, 1st 1000 kWh $0.013000 Winter, Addt'l kWh $0.002999

#	Rider	Rider Name	Definition	Rate Schedule	Applicability	
				Other		RS
14	**RE**	Retail Energy	Provides recovery of energy costs. Rider RE recovers costs related to the provisions of electric energy (kWh) in the Duke Energy service territory, as determined through the competitive bid process (SSO Auction). For the purpose of deriving Rider RE rates from the overall SSO Auction results, the costs of capacity included in the price of the SSO Auction result will be deducted from the overall price of the SSO Auction approved by the Commission for delivery during the rate-effective year.	All rates are per kWh	Bypassable	Summer, 1st 1000 kWh $0.047951 Summer, Addt'l kWh $0.057051 Winter, 1st 1000 kWh $0.047951 Winter, Addt'l kWh $0.026654
15	ESSC	Electric Security Stabilization	The purpose of this rider is to provide stability and certainty regarding the Company's provision of retail electric service as a Fixed Resource Requirement entity as defined by the Regional Transmission Operator while also operating under the current Electric Security Plan as approved by the Commission.	All rates are per kWh/kW	Non-bypassable	Summer, 1st 1000 kWh $0.007124 Summer, Addt'l kWh $0.009465 Winter, 1st 1000 kWh $0.007124 Winter, Addt'l kWh $0.001644
16	**LFA**	Load Factor Adjustment	The purpose of this rider is to stabilize electric service by enhancing the benefits associated with high load factor customers under current rates. The rider will be structured with a demand charge and an energy credit. The energy credit will be used to reduce the customer's applicable energy charges for electric service, representing a decrease in charges to the customer. The credit provided in this rider will be adjusted quarterly to ensure, in the aggregate, that the dollars credited via this rider are equal to the charges.	LFA Charges are per kW/kVA LFA Credits are per kWh Rates affected are DS, DP, TS	Interclass balancing Revenue neutral	

#	Rider	Rider Name	Definition	Rate Schedule Other	Applicability	RS
17	**SCR**	Supplier Cost Reconciliation	The Supplier Cost Reconciliation Rider recovers any differences between payments made to suppliers, as determined through the competitive bid process (SSO Auction), and the revenues collected through Rider RC and Rider RE.	The charge for all customers is $0.001846 per kWh	Non-bypassable	
	EE-PDRR	Energy Efficiency and Peak Demand Response Recovery Rate	Allows for rates to be applied related to EE & Peak Demand Response Recovery.	Residential Customers $0.003443 per kWh Non-Residential Customers $0.001405 per kWh (Other Than Service Under Rates DS, DP, TS, RTP) Non-Residential Customers Under Rates DS, DP, TS, RTP $0.001670 per kWh		
18	**EE-PDR**	Energy Efficiency and Peak Demand Response Recovery	Establishes provisions for the recovery of costs associated with the energy efficiency and peak demand response programs.	Rider EE-PDR applies to the following rates: RS, ORH, TD-AM, TD, CUR, RS3P, RSLI, TD-LITE, TD-CPP_LITE, TD-2012, DS, GS-FL, EH, DM, DP, TS, SFL-ADPL The monthly amount computed under each of the rate schedules to which the rider is applicable shall be increased or decreased by the EE-PDR Charge at a rate per kWh of monthly consumption and, where applicable, a rate per kilowatt of monthly billing demand, in accordance with the formula outlined in the Company tariff.	Non-bypassable	
19	**DDR**	Distribution Decoupling	As a three-year pilot program or until the Company's next distribution rate case, applicable customers shall be assessed a monthly charge or credit which reflects an adjustment to rates that will effectively remove Duke Energy Ohio's distribution-related through-put incentive.	All DDR charges/credits per kWh Rates TD-2012 & TD-2013 $0.000168 All Other Applicable Rates - See Chart	Non-bypassable	0.000168

#	Rider	Rider Name	Definition	Rate Schedule Other	Applicability	RS
20	**DM-I**	Industrial Demand Management Pilot Program	Applicable to industrial customers who employ manufacturing processes that are time sensitive, have an average actual monthly demand not exceeding six hundred kilowatts, and require a defined year-round off peak period.	Monthly charge of $7.50 for each installed TOU meter. Billing occurs per the provisions of "off peak" and "on peak" periods outlined in the Company tariff.	Bypassable	
21	**OET**	Ohio Excise Tax	Applicable to all jurisdictional retail customers except that those who meet the eligibility requirements contained in section 5727.81 of the Ohio Revised Code may elect to self-assess this tax.	Applicable to all usage on and after May 1, 2001 as follows: First 2,000 kWh - $0.00465 per kWh Next 13,000 kWh - $0.00419 per kWh Additional kWh - $0.00363 per kWh	Bypassable	
22	**RTO**	Regional Transmission Organization	Allows for charges that include costs charged to or imposed upon the Company by FERC and FERC-approved RTOs.			$0.000000 per kWh
23	**RECON**	Fuel and Reserve Capacity Reconciliation	Allows for recovery of fuel costs.	The charge/(credit) for residential customers is $0.000000 per kWh. The charge/(credit) for non-residential customers, excluding TS, is $0.000000 per kWh. The charge/(credit) for TS customers is $0.000000 per kWh. **No Rate Charged to Customers Under Rider RECON.**		
24	**GSS**	Generation Support Service	Applicable to any general service customer having generation equipment capable of supplying all or a portion of its power requirements for other than emergency purposes and who requires supplemental maintenance or backup power.	Monthly Distribution Reservation Charge See Rates DS, DP, TS Monthly Transmission Cost Recovery Reservation Charge Rates DS, DP, TS - Per Rider BTR/RTO		

#	Rider	Rider Name	Definition	Rate Schedule Other	Applicability	RS
25	NM-H	Net Metering - Hospitals	Hospital customer generators that are billed or credited the difference in an applicable billing period between the amount of electricity supplied by the Company and the amount of electricity generated by the hospital that is delivered to the Company.	Electricity charged at rate hospital would pay if not taking service under Rider NM-H. Electricity credited at the market value (PJM) as of the time the hospital generated the electricity. **No Rate Charged to Customers Under Rider NM-H.**		
26	NM	Net Metering	Customers on this rate are billed or credited the difference in an applicable billing period between the amount of electricity supplied by the Company and the amount of electricity generated by such respective Customer that is delivered to the Company.	Electricity charged at normal customer rate. Electricity credited by using the kWh charge as determined by Rider RE, Retail Energy, of the applicable rate tariff. **No Rate Charged to Customers Under Rider NM.**		
27	TS	Temporary Service	Rate of service for customers who obtain service for no more than 6 months.	Normal charges for service under applicable rate. Customer will also pay in advance the entire cost of installing and removing facilities. **No Rate Charged to Customers Under Rider TS.**		

#	Rider	Rider Name	Definition	Rate Schedule Other	Applicability	RS
28	X	Line Extension Policy	Rate to extend existing distribution lines to serve new customers.	**Residential Single Family Homes:** Company shall be responsible for all costs of standard service installation up to $5,000 per lot. Customers shall be responsible for any costs above $5,000. Customer shall be responsible for the incremental costs of premium services (Company's cost for premium installation minus the cost of a standard installation). **Residential, Non-master-metered, Multifamily Installations:** Company shall be responsible for all costs of standard service installation up to $2,500 per unit. Customers shall be responsible for any costs above $2,500. Customer shall be responsible for the incremental costs of premium services (Company's cost for premium installation minus the cost of a standard installation). **Nonresidential Customers:** Company shall be responsible for 60% of the cost of standard service installation. Customer shall remit 40% of the cost of standard service installation prior to the start of construction. This shall be considered Contribution in Aid of Construction (CIAC). Customer shall be responsible for the incremental costs, including CIAC costs, of premium services (Company's cost for installation minus the cost of a standard installation).		

#	Rider	Rider Name	Definition	Rate Schedule Other	Applicability	RS
29	**EEPF**	Electricity Emergency Procedures for Long Term Fuel Shortages	Establishes emergency procedures.	Outlines voluntary and mandatory percentage reductions in power consumption by customers during periods of protracted fuel shortage. Provides for penalties to be assessed for non-compliance. No Rate Charged to Customers Under Rider EEPF.		
30	**EEPC**	Emergency Electric Procedures	Establishes emergency procedures.	Outlines procedures for the curtailment of electric service due to emergency conditions. Defines essential customers and provides terms for reduced service to those customers. No Rate Charged to Customers Under Rider EEPC.		
31	**LM**	Load Management	Establishes off peak provisions for customers receiving service under their respective distribution or transmission service rate schedules.	Outlines terms for customers with demand meters having a programmable time-of-use register and an average monthly demand that does not exceed 500 kilowatts. Also outlines terms for customers with an interval meter. No Rate Charged to Customers Under Rider LM.		
32	**TES**	Thermal Energy Storage	Outlines service agreements for customers who install thermal heating or cooling.	Customers' bills shall be computed in accordance with the provisions of the respective distribution or transmission service tariff, or as provided for by Rider LM. No Rate Charged to Customers Under Rider TES.		

#	Rider	Rider Name	Definition	Rate Schedule Other	Applicability	RS
33	**GP**	Green Power	Establishes a program for customers who wish to purchase green units including RECs.	The GoGreen Program includes the purchase of Renewable Energy Certificates and/or Carbon Credits related to alternative energy sources. Minimum purchase is 2 100kWh units. Additional purchases to be made in 100 kWh unit increments. Cost for the units is shown under the affected rates. All other rates will have an individually calculated GoGreen rate per service agreement which may also include carbon credits.		$1.00 per unit per month
34	**EER**	Energy Efficiency Revolving Loan Program	Energy efficiency loan program established by Ohio Amended Substitute Senate Bill No. 3. The rider is applicable to all jurisdictional retail customers, including interdepartmental sales.	The amount charged is $0.09 per customer per month. The rider shall remain in effecft no later than December 31, 2010.		
35	**BDP**	Backup Delivery Point Capacity	Allows for additional electric delivery points to be made available to non-residential customers who request the service.	Connection Fee - Required only if an additional metering point is required $300.00 Monthly charges will be based on the unbundled distribution and/or transmission rates of the customer's most applicable rate schedule and the contracted-for reserved backup delivery point capacity. Customer shall also be responsible for the acceleration of costs to the extent that the revenue requirement for such costs exceeds the monthly charges established above, if any, which would not have otherwise been incurred by the Company absent such request for additional delivery points.		

#	Rider	Rider Name	Definition	Rate Schedule Other	Applicability	RS
36	**MDC**	Meter Data Charges	Applies to customers that have meter pulse equipment and/or interval metering equipment.	One Month of electric Interval Meter Data $24.00 Twelve months of electric Interval Meter Data $32.00 Interval Meter Data Printout $13.00 Electric monthly interval data with graphical capability accessed via the internet $20.00 per month		
37	**MSC**	Meter Service Charges	Applies to customers that request the Company to install interval metering and meter pulse equipment and to provide certain meter related services that otherwise are not provided by the Company.	Standard Meter Tests $41.00 Replace Meter with Interval Meter and Modem - 15 minute intervals $446.00 Replace Meter with Interval Meter and Modem 5 minute intervals $968.00 Installation of Meter Pulse Equipment $380.00 Additional Trips to Meter Site $58.00/visit Cellular telephone installation and monthly access fee $55.00/month		
38	**SBS**	Summary Billing Service Pilot	Company will render one Summary Billing Statement each month that will summarize the customer's accounts. Additionally, customers may elect to receive a report that provides details of the associated accounts.	No Rate Charged to Customers Under Rider SBS.		

******** The shaded are listed by Duke as riders, but do not involve routine recovery filing.********

BEFORE
THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Carbon Pollution Emission Guidelines for	:	EPA-HQ-OAR-2013-0602
Existing Stationary Sources Electric	:	
Utility Generation Units.	:	

COMMENTS
SUBMITTED ON BEHALF OF
THE PUBLIC UTILITIES COMMISSION OF OHIO

December 1, 2014

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COMMENTS
SUBMITTED ON BEHALF OF
THE PUBLIC UTILITIES COMMISSION OF OHIO

I. Introduction

The Public Utilities Commission of Ohio (PUCO) is charged with ensuring that all consumers in Ohio have access to reliable electric service at affordable rates. These consumers include Ohio's roughly 11.5 million residents, as well as the businesses that support these residents and Ohio's growing economy.

Ohio's economy is energy intensive due to the strength of Ohio's industrial/manufacturing industries. In 2012, Ohio had the sixth highest energy consumption rate in the United States, and on an annual basis more than 50 percent of Ohio's energy consumption is derived from the industrial/manufacturing industries. The impact of these industries extends to the furthest corners of Ohio, as they often serve as the lifeblood of entire cities and regions. Ohio's residents and communities are dependent on these industries for employment and prosperity.

The continued availability then of reliable electric service at affordable rates is critical to the success of Ohio's economy and the health of its residents. The PUCO will not debate the policy merits of a plan to reduce carbon emissions from electric generating units (EGUs). Instead, the PUCO will explain the technical flaws in the Clean Power Plan (CPP) and identify the impact of the CPP on the delivery of reliable and affordable electric service to consumers in the state of Ohio.

A. Ohio's generation is deregulated and resides in an economic marketplace

If the United States Environmental Protection Agency (US EPA) is to attempt to regulate carbon emissions from Ohio EGUs, it is of singular importance that US EPA has a full understanding of the regulatory environment that these EGUs exist within.

The PUCO's authority is conferred by state statute. As the regulation of public utilities is complex and exceptionally technical in nature, the Ohio General Assembly tasks the PUCO with promulgating administrative rules in order to carry out the responsibilities that the statute has established. While the PUCO has significant discretion in carrying out its statutory responsibilities, over the past 15 years its jurisdiction has changed significantly due to changes in Ohio's electricity laws. Ohio has transitioned from a vertically-integrated, traditional rate of return utility construct, where an incumbent utility provides service from generation to local distribution, to a competitive retail generation market where customers can choose their generation supplier.

Currently, Ohio is one of only 13 states in the country that is completely deregulated and offers energy choices for electricity and natural gas.[1] The EGUs that were previously regulated through traditional rate of return ratemaking and were part of a larger vertically-integrated utility are now either entirely divested from Ohio's electric distribution utilities or are currently undergoing the necessary corporate separation to achieve this deregulated construct.[2]

Because Ohio no longer regulates generation facilities, the state generally relies on the wholesale electric market to meet the state's energy and capacity needs. Wholesale electric markets are open and accessible to approved parties that can offer, purchase or resell electricity as a commodity. Due to the open nature of wholesale electric markets, participating parties range from independent power producers and utility generation affiliates to competitive marketers or suppliers. In a deregulated state, energy prices are set not by regulated rates of return but by competition and market forces.

This construct contrasts sharply with the majority of states that have traditional, vertically-integrated utilities. Under the traditional approach, an incumbent utility maintains responsibility for generation, transmission and distribution. Utilities charge generation rates set by state regulators and receive a rate of return. Consequently, vertically-integrated states maintain exclusive jurisdiction over individual generation units, whereas

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[1] Consistent with Ohio Revised Code 4928.143(B), while a deregulated state, Ohio does offer the option for an electric distribution utility to file an electric security plan that includes provisions relating to the supply and pricing of electric generation service.

[2] The Dayton Power and Light Company is in the process of divesting its generation assets from the distribution utility company. Full corporate divestiture will be complete by 2017.

Ohio relies on other regional and federal entities to manage electricity markets that send appropriate price signals to incent and maintain generation units.

As a result of Ohio's shift to a competitive electricity market, the PUCO relies on the Federal Energy Regulatory Commission (FERC) to regulate interstate transmission and the wholesale sales of electricity pursuant to the Federal Power Act (FPA). FERC reviews the activities in wholesale markets to determine whether electric rates are just and reasonable. In addition, FERC is responsible for protecting the reliability of high voltage interstate transmission systems and setting reliability standards.

In order to facilitate open and competitive marketplaces, FERC authorized the creation of regional transmission organizations (RTO) to move electricity from generation units across interstate regions. PJM Interconnection, LLC (PJM) is the RTO charged with coordinating the movement of wholesale electricity across Ohio. By coordinating the transmission of electricity, PJM can provide long-term planning that identifies the most efficient and cost-effective means to ensure reliability on a regional basis.

PJM's territory includes all or portions of 13 states and the District of Columbia. Ohio accounts for more than one-fifth of the load that PJM serves, making Ohio the largest state served by PJM. In fact, Ohio's energy load is larger than the combined loads of Maryland, Delaware, New Jersey and the District of Columbia.

PJM schedules and dispatches generation resources based upon a concept called security constrained economic dispatch (SCED). Specifically, PJM considers and selects the least expensive generation resources to dispatch first in order to meet energy demands while maintaining the reliability of the transmission grid. As demand increases, PJM selects more expensive generation resources to dispatch. Prices subsequently increase as PJM calls on more expensive generation to meet increases in demand.

Because less efficient generation units may not be called upon as frequently as more efficient generation resources under PJM's SCED mechanism, PJM created a capacity construct called the Reliability Pricing Model (RPM). One of the objectives of RPM is to encourage all generation units to be available to serve consumers during periods of high demand. In this capacity marketplace, generation units are paid to be available and ready for periods of peak demand. These units are then paid again if dispatched through the daily energy marketplace by PJM's SCED mechanism.

The PJM capacity market not only ensures that generation units are available; it serves an additional role of providing long-term price signals. The goal of these long-term price signals created through PJM's capacity market is to allow for the continued maintenance of all existing generation facilities and to provide an incentive for the development of new generation resources to maintain reliability.

These capacity and SCED mechanisms promulgated by PJM are sensitive economic marketplaces. These marketplaces are overseen by PJM and an independent market monitor (IMM) who serves to ensure that these economic marketplaces are not polluted by non-economic and anti-competitive behavior.

US EPA, through its proposed CPP, would considerably alter the nature of these economic marketplaces via the introduction of environmental considerations. As the PUCO's comments will set forth, the introduction of environmental considerations not only serves to conceptually damage these economic marketplaces, but to increase considerably the cost of electricity to consumers. Furthermore, the introduction of environmental considerations into PJM's economic markets would place some generation units in Ohio at risk for closure. Simply put, the CPP threatens the primary principle that the PUCO exists to protect – the delivery of reliable electric service at affordable rates.

B. Clean Power Plan

On June 2, 2014, US EPA issued a notice of proposed rulemaking to establish emission guidelines for states to address greenhouse gas (GHG) emissions from existing fossil fuel-fired EGUs. This proposal, known as the Clean Power Plan, or CPP, creates state specific carbon dioxide (CO_2) emission targets.

The CPP utilizes four "building blocks" to derive each state's CO_2 emission targets. In building block 1, the CPP asserts that coal-fired EGUs could achieve a six percent heat rate reduction which would allow for an equivalent six percent reduction in CO_2 emissions. In building block 2, the CPP proposes an additional means to reduce carbon emissions through the re-dispatch of natural gas combined cycle (NGCC) units to an increased capacity factor of 70 percent.

In building block 3, the CPP proposes and sets targets for the increased use of renewable and nuclear resources. Finally, in building block 4, the CPP calls for greater use of demand-side energy efficiency (EE) programs to further reduce carbon emissions.

C. Clean Air Act Section 111(d)

US EPA asserts that it has the authority to promulgate the CPP through Section 111(d) of the Clean Air Act (CAA), and that the CPP meets the best system of emissions reduction (BSER). The BSER acts as the model for the standard of performance for each state in reducing GHG.

In accordance with the CAA, to achieve the proposed emissions reductions, the BSER must take cost considerations into account, as well as health, environmental and energy impacts.[3] US EPA avers that the CPP's four building blocks comprise the BSER. The CPP requires individual state compliance, and also provides a mechanism to submit a regional plan that would incorporate multiple states' compliance targets.

II. Comments of the Public Utilities Commission of Ohio

The PUCO's legal and technical comments reflect its unique perspective as the state regulator of Ohio's public utilities. In addition to our comments, the Ohio Environmental Protection Agency (Ohio EPA) and the Ohio Attorney General are submitting comments addressing the CPP. Throughout these comments, the PUCO will cross-reference certain matters within Ohio EPA's and the Ohio Attorney General's comments that primarily fall under their respective competencies.

The PUCO's comments first identify legal challenges to the CPP. The PUCO understands that the CPP reflects a proposed rule that is not yet finalized. However, in

[3] 42 U.S.C. § 7411(a)(1), 2013; See Appendix B:1.

order to preserve all legal and appellate rights, legal arguments are raised herein. In addition, Ohio EPA and the Ohio Attorney General address legal concerns with the CPP in their respective comments.[4] These comments do not equate to a brief that is to be submitted to a court of law.

The majority of the comments will address (assuming *arguendo* that the CPP survives a legal challenge) the technical flaws of the CPP as they pertain to Ohio. These technical comments are addressed by building block. Included in these technical comments are precise analyses and data that expose cost and reliability concerns for Ohio's consumers.

A. Legal Arguments

1. The CPP conflicts with specific reliability responsibilities vested with FERC.

In the CPP, US EPA uses CAA Section 111(d) as the basis to justify its emission reduction requirements. However, the CAA was not intended to be used as a mechanism to regulate electric power systems, as evidenced by the FPA's specific references to both the United States Department of Energy (US DOE) and FERC in regard to generation use and electricity reliability. The FPA not only speaks to electric generation, unlike the

[4] "Ohio EPA Comments on US EPA's June 18, 2014 Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule," Ohio Environmental Protection Agency, [79 FR 34830], 2014, 19-34.

CAA, it includes a mandate requiring the federal agency to ensure reliability and the adequacy of retail electric service. The CPP would prevent, or at the very least limit, FERC from carrying out its legislative mandate.

a. Through the FPA, Congress vested authority with FERC to ensure the reliability and the adequacy of electric service.

The FPA clearly vests authority over reliability and electric service adequacy with FERC. As stated in the FPA, US DOE has the authority to require power plants to operate. However, the statute also provides, upon any claim of inadequate or insufficient service by a state regulatory commission, that FERC must take action and respond to any allegations that have been raised. Responding to state commission claims is not permissive; FERC has an obligation to:

> [p]erform any and all acts, and to prescribe, issue, make, amend, and rescind such order, rules, and regulations as it may find necessary or appropriate to carry out the provisions of the Federal Power Act.[5]

As discussed, the CPP's four building blocks place reliability in a precarious position. Even if the CPP is deemed permissible, deference must be given to the FPA if reliability concerns are raised. The FPA, as the most relevant and specific statute, must prevail in any future conflicts that may arise as a result of the CPP's strain on reliability.

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[5] 16 U.S.C. § 825h; See Appendix B:2.

b. The CPP could prevent FERC from carrying out its responsibility directed from Congress.

By mandating the means and methods by which states must reduce carbon emissions from systems of generation, the CPP undermines FERC's ability to fulfill its legislative mandate requiring it to resolve claims of inadequate generation service. Consequently, the CPP, even if legally permissible, must yield to the FPA as it prevents a federal agency from fulfilling a legislative mandate.[6] The CPP cannot be implemented because it would prevent a federal agency from carrying out its clear, unambiguous legislative mandate.

c. The principles of statutory construction dictate that the FPA prevails over the CPP and requires the establishment of a reliability safety valve to avoid interference with a nondiscretionary legislative mandate.

Consistent with the principles of statutory construction, there is an implicit presumption that where both a general statute and specific statute appear to address the matter, the more specific statute must prevail.[7] Congress has assigned FERC, through FPA 207, an explicit mandate requiring FERC to fix or address any allegation of inadequate service. The CPP, under Section 111(d), dramatically alters the nation's treatment of electric energy in interstate commerce, and creates a conflict with the FPA. This conflict

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6 *See* The Electricity Journal, Jan./Feb/2012, Vol 25, Issue 1, "Walking the Line between the Clean Air Act and the Federal Power Act: Balancing Emission Reductions and Bulk Power Reliability". *See also* 551 US 644, 661-669 (2007); 426 US 776 at 778 (1976); 421 F.3d 618, 630 (8th Cir. 2005). See Appendix B:18.

7 *Id*.

foreshadows the possibility of a generation unit operating under environmental constraints needing to run more frequently than permitted under the CPP construct. As both the FPA and CAA would dictate how a generation unit should operate, the FPA would prevail as it explicitly assigns authority to FERC to correct inadequate service that hinders reliability, while the CAA does not.[8]

Further, as there is no evidence CAA 111(d) was intended to supersede the FPA's assignment of reliability assurance to FERC, the CPP must introduce a reliability safety valve to avoid preventing a federal agency from fulfilling a legislative mandate.

2. The CPP regulates the use of electric energy in interstate commerce, violating principles of cooperative federalism.

US EPA, through the CPP, wades into foreign jurisdictional waters. Whether intentional or not, US EPA is attempting to manipulate an economic marketplace for wholesale power that is regulated by FERC. Exclusive jurisdiction over all facilities for such transmission or sale of electric energy is vested to FERC consistent with FPA section 201(b)(1).[9]

US EPA's attempted market usurpation would coerce RTOs into an enforcement role whereby RTOs would become responsible for, at a minimum, the dispatch elements of any approved CPP state plans. This would evoke two legal quandaries under FPA 201. First, US EPA does not have the jurisdiction to create new duties for RTOs; that

8 *See Bulova Watch Company v. United States*, 365 U.S. 753, 758; See Appendix B:21.

9 16 U.S.C. § 824(b)(1); See Appendix B:3.

authority is vested with FERC. Likewise, RTOs are charged with ensuring reliability through economic principles, not environmental enforcement.

Finally, the CPP expands into matters that are traditionally reserved to the states, including the siting and permitting of generation facilities.[10]

a. The CPP would violate FPA 201 by creating a means in which state implementation plans would interfere with wholesale power markets that are regulated by FERC.

If building block 2 is implemented as proposed by US EPA, the CPP would unequivocally impact wholesale power markets that are regulated by FERC. Building block 2 would place NGCC units at the front of the dispatch line, and coal-fired units at the back, distorting a marketplace that is based upon economic bidding and pricing. Aside from distorting this marketplace, the legal reality is that by creating a resource preference for the sale of electric energy or changing the way energy resources are dispatched in wholesale energy markets, US EPA has exceeded its jurisdiction and contradicted FPA 201.

The FPA clearly vests FERC with authority over the construction and operation of wholesale electric markets. In Order 2000,[11] FERC amended its regulations to identify characteristics and functions that must be met prior to forming an RTO or independent

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[10] As acknowledged by FERC, integrated resource planning and authority of the siting, permitting and construction of transmission facilities are substantive matters traditionally reserved to the states. *See* Order No. 1000, FERC Stats. & Regs., 31, 107, and 323; See Appendix B:23.

[11] 89 FERC § 61,285, Dec. 20, 1999, 18 CFR part 35; See Appendix B:4.

system operator. The formation of RTOs was encouraged by FERC in order to "promote efficiency in wholesale electricity markets and ensure that electricity consumers pay the lowest possible price for reliable service." Although FERC still has the authority to determine whether rates are just and reasonable, RTOs have ratemaking authority under FPA 205.[12] US EPA, through the CPP, proposes to change the entire complexion of a marketplace that is not within its jurisdiction to change.

b. The CPP creates new duties and assigns responsibility to RTOs.

Under FPA 205, FERC, through Order 2000, has provided guidance and authority to establish RTOs. Only FERC possesses the authority to direct public utilities and non-public utilities to consider regional coordination associated with joining an RTO.[13] Further, it is FERC, not US EPA, that sets the characteristics and requirements an RTO must meet in order to provide reliable, non-discriminatory service. US EPA, through the CPP, wedges itself between FERC and RTOs by tasking enforcement and new dispatch responsibilities upon RTOs.

RTOs are responsible for setting regional capacity requirements to maintain reliability. Regional capacity obligations are then assigned to load serving entities throughout the RTO region. The responsibility for reliability is not permissive. FERC and the North

[12] 16 U.S.C. § 825(d); See Appendix B:20.

[13] 89 FERC 61,285 (1999).

America Electric Reliability Corporation (NERC) standards require RTOs to maintain reliability over multi-state electric systems.

US EPA lacks authority through CAA 111(d) to assign generation dispatch parameters to the RTOs, whether that assignment is explicit or implicit. By changing the methodology in which generation is dispatched by the RTOs, US EPA treads on the jurisdiction of FERC. As will be discussed herein, the CPP allows for each individual state to dispatch generation without regard to regional electricity markets. Not only that, but by allowing each state within an RTO to determine its own unique dispatch parameters, the CPP creates the likelihood of contradictory and conflicting implementation plans between states.

Further, the CPP places RTOs in the precarious position of being tasked with following contradictory state dispatch instructions. Specifically, Ohio would need to direct PJM, as the system operator, how and when generating units within the state's borders must be operated to ensure state compliance. PJM would then, *de facto*, become the statutory agent responsible for ensuring Ohio's compliance, as PJM would need to report back to Ohio which units are being dispatched in accordance with the principles set forth in building block 2.

c. The CPP's regulation of generation dispatch extends to matters subject to state regulation.

In the state of Ohio, PJM is responsible for SCED. Deregulated states like Ohio place their trust in RTOs to ensure there is resource adequacy to meet load forecasts in an economically sound manner. Although Ohio operates in a competitive retail electric market, the PUCO still maintains the ability to ensure that there is sufficient electricity to meet demand. Ultimately, PJM is responsible for long-term forecasting that must consider energy demand, peak loads and reserves. Nonetheless, while Ohio presently does not perform IRP functions, US EPA steps into resource planning jurisdiction that rests with RTOs or states.

Under the CPP, deregulated states that have deferred some of their resource planning rights would be forced to allow a federal entity, with no jurisdictional authority or expertise over wholesale electric markets, to dictate how states should meet energy demand. Even as the federal entities responsible for ensuring reliability, neither FERC nor NERC have the jurisdictional authority to perform state IRP functions. US EPA has completely overstepped its authority in this regard as well.

3. Even if the CPP were jurisdictionally permissible, it still conflicts with the FPA because changing economic dispatch to environmental dispatch would cause rates to no longer be just and reasonable.

In addition to the fact that each state may establish its own dispatch priorities and policies to the detriment of RTOs and neighboring states, the CPP does not consider that the corresponding rate changes as a result of re-dispatch may become unjust and unreasonable. As a result, US EPA, through the CPP, violates the FPA.

FERC has both the authority and responsibility to ensure that rates, charges, classifications and services of public utilities are just and reasonable and not unduly discriminatory under FPA sections 205 and 206. Specifically, FPA section 205 requires FERC to ensure that all "rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the [FERC], and all rules and regulations, affecting or pertaining to such rates or charges" are just and reasonable. Similarly, FPA section 206 requires FERC to prevent any rate, charge or classification that is unjust and unreasonable, or unduly discriminatory or preferential. Market-based rates can be considered just and reasonable so long as there are no barriers to new entry and transmission market power is mitigated in nature.

The impacts of the CPP, coupled with the proposed 111(b) regulations, would not only lead to the premature retirement of many coal-fired generation units, but would preclude any likelihood of another coal generation facility being built. While this goal is certainly ambitious, the reality is that its impact on the wholesale electric marketplace would increase costs for Ohio's consumers dramatically.

The CPP is not only harmful to Ohio's economy, but to the entire wholesale market within PJM. By limiting and removing participation of coal-fired generation units from the PJM footprint, these units cannot participate in organized wholesale markets. Consequently, generation rates would not be just and reasonable as required by the FPA.

B. The CPP's timing and implementation schedule is neither credible nor viable.

The ambitious compliance deadlines within the CPP do not account for the multiple layers of structural changes that would have to take place prior to developing an implementation plan. Specifically, the CPP lays out the following deadlines:

Final rule:	June 2015
Deadline for initial plan submittals:	June 2016
Extended deadline for plan submittal:	June 2017
Extended deadline for multi-state submittal:	June 2018
CPP performance start date:	January 2020

It would take at least several years for state legislatures and administrative agencies to amend and revise their respective statutes and administrative rules. Even if the CPP could be established on a more aggressive timeline, the earliest possible date for performance to start based on the proposed plan is 2022. Furthermore the timeline ignores necessary planning that must occur within the RTO construct as well as reliability planning that must occur with NERC.

1. The proposed schedule does not provide adequate time for changes in state law.

Under the current proposal, Ohio would be given at most two years to not only develop and create an implementation plan, but to implement necessary legislative revisions through the Ohio General Assembly and subsequent rulemaking through state agencies.[14]

As Ohio EPA sets forth within its comments, significant time would be necessary to draft legislation and engage in the implementation process.[15] Typically, a minimum of six months would be required to draft all necessary legislative changes to Ohio's current competitive retail electric service laws. This legislation would then need to be introduced before the Ohio General Assembly, hearings held and the statutory language vetted and eventually adopted. The Ohio General Assembly would likely need to devote several years to implementing the extensive overhaul necessary to meet the path charted in the CPP.[16]

After the Ohio General Assembly takes action, the burden would shift to state regulatory agencies like the PUCO and Ohio EPA to update and amend administrative rules.

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[14] The PUCO understands that there is an extended deadline available for multi-state plans, however, this is equally unrealistic. A multi-state plan would require more time than an additional year for coordination between multiple states. Further, it is likely that a multi-state plan would require an interstate compact, necessitating approval from Congress.

[15] "Ohio EPA Comments on US EPA's June 18, 2014 Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule," Ohio Environmental Protection Agency, [79 FR 34830], 2014, 128-130.

[16] *Id.*

The PUCO is familiar with this process and it could take anywhere from 18 to 24 months to complete.

Specifically, the PUCO is required by law to conduct an initial workshop on any proposed rule revisions, open a docket for that rule and solicit feedback from stakeholders. Once the PUCO approves new or amended rules after allowing an open and participatory process, the rules remain subject to a rehearing process. This rehearing process typically takes at least six months to complete. Realistically, in light of these two processes, Ohio legislative and rulemaking proceedings would likely require extensive time beyond the CPP's overly ambitious timeline.

2. Because the CPP changes the treatment of generation resources, additional time must be allocated for the regional transmission organization to amend its tariffs and update its structure.

There are 14 jurisdictions that are members of PJM,[17] each with their own policy objectives and generation resource mix. It would take an extensive amount of time for each state to develop an implementation plan in order to meet the CPP's stringent timeframe. PJM would need to review each of these plans in order to determine how to structure the current marketplace, determine any reliability implications and update its tariffs.

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[17] The District of Columbia is also a member of PJM but is not required to submit a State Implementation Plan.

Upon the submission of implementation plans, PJM would likely conduct an up-front analysis of each state plan to evaluate both intrastate and interstate reliability issues. Modeling reliability impacts would be an intensive process for PJM, particularly because there is no hard deadline in the CPP as there was in Mercury and Air Toxics Standards (MATS) by which PJM could measure the impacts of the CPP. This is further complicated by the possibility that states may submit multi-state regional plans with deadlines beyond those of single state plans. PJM would need to run its reliability analysis multiple times to reflect the multitude of possibilities that could arise from the submittal of many different state plans. PJM would also need ample time to update the structure of its markets and to amend tariffs based upon all of these plans

3. The proposed schedule does not contemplate the intricacies of a forward capacity market.

As previously discussed, PJM's RPM capacity construct is based on making capacity commitments three years ahead of the actual electricity delivery year. The rationale behind a forward capacity market, as opposed to a short-term capacity market, is to stimulate investment in new generation and maintain existing generation by creating long-term price signals.

In order to participate in the RPM process, generators are required to meet "must offer requirements" during the actual delivery year. PJM depends upon these generation units to offer their resources into energy markets during the actual delivery day. By the time the final rule is issued in June 2015, PJM would have already conducted its capacity auction for the 2018/2019 delivery year.

The CPP appears to be unfamiliar with this concept. RTOs depend upon all existing generation units and plan ahead for future years in order to ensure there is sufficient generation to meet demand. At a minimum, the availability of certain generation units that have already been earmarked to produce energy would be placed in doubt, causing uncertainty for PJM, states, markets, the economy and all energy consumers. It would be unclear whether units that have already committed to produce energy in the forward capacity market would be able to perform as originally contemplated.

The CPP does not address impacts on forward capacity markets or provide additional time for implementation in light of forward capacity markets. It is impossible for state plans to be implemented by the latest possible deadline of 2018, particularly when capacity generation resources will have already been procured through 2021/2022. Assuming there are no administrative challenges or burdens, the earliest possible compliance year for all states in the PJM footprint is 2022.

4. The proposed schedule does not provide adequate time for NERC to perform necessary reliability analyses.

NERC, the designated electric reliability organization for the United States, strives to ensure that the electric grid maintains the high standard of reliability to which Americans are accustomed. NERC protects reliability by creating standards for the grid that are meant to address reliability risks and threats. In addition, NERC preserves reliability by monitoring the generation resource mix, generation retirements, capacity reserve margins, transmission planning and other items necessary to meet a high standard of reliability.

NERC, in a study entitled "Potential Reliability Impacts of EPA's Clean Power Plan" (NERC Reliability Study) expresses concern that the schedule proposed by US EPA is too ambitious. In its report, NERC states:

> State and regional plans must be approved by the EPA, which is anticipated to require up to one year, leaving as little as six months to two years to implement the approved plan. Areas that experience a large shift in their resource mix are expected to require transmission enhancements to maintain reliability. Constructing the resource additions, as well as the expected transmission enhancements, may represent a significant reliability challenge given the constrained time period for implementation. While the EPA provides flexibility for meeting compliance requirements within the proposed time frame, there appears to be less flexibility in providing reliability assurance beyond the compliance period.[18]

The NERC Reliability Study goes on to expound upon transmission development and construction, stating that "long lead times for transmission development and construction require long-term system planning – typically a 10-15 year outlook."[19]

Again, US EPA, through the CPP, takes an approach whereby it seeks to act in the energy industry without the requisite knowledge or understanding of the plan's far-reaching impacts. The NERC Reliability Study highlights that the risks to reliability are legitimate. Reliability of the electric grid cannot be compromised, as the health of this

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[18] "Potential Reliability Impacts of EPA's Clean Power Plan," North American Electric Reliability Corporation, Nov. 2014, 2. See Appendix B:17.

[19] *Id*. at 20.

nation's economy and populous depends on the delivery of reliable energy. Based upon the NERC Reliability Study, it appears that the CPP and its ambitious implementation timeframe could inflict serious harm by jeopardizing reliability.

C. Assumption Flaws

In calculating the state of Ohio's goal emission rate, the CPP relies on faulty assumptions instead of using the best available information.

1. Mathematical Flaws

In Appendices 1 and 2, the CPP does not use correct generation figures for Ohio. To illustrate, consider the following:

- The Dresden Plant's net generation for 2012 was 2,599,011 megawatt hours (MWh), whereas US EPA's eGRID data calculated it as 470,486 MWh.
- The "Under Construction NGCC Capacity (MW)" for Ohio is stated at 539 megawatts (MW) for the Dresden Plant. However, the Dresden Plant has been built and is already accounted for by US EPA in the existing NGCC calculations.
- US EPA calculates existing Ohio nuclear capacity at 2,150 MW using United States Energy Information Administration (US EIA) data. US EIA Form 860 states that Ohio's existing nameplate capacity is 2,282.5 MW.

The CPP assumes that all generation units can run on nameplate capability. Both summer and winter capabilities are significantly less than nameplate capability. In Ohio, the summer capability for NGCC plants is 447.2 MW less than the nameplate capability.[20] This error most impacts building block 2, which relies extensively on generation dispatch capabilities.

2. Mass-Based Emission Target Flaws

Assuming *arguendo* that the mass-based approach is even viable, it is worth noting that there were errors in U.S. EPA's Nov. 6, 2014 addendum providing new guidance for converting target emissions rates to mass emissions targets. Specifically, in converting pounds to tons, US EPA relies upon a figure of 2204.62, whereas the original June 2 Notice of Proposed Rulemaking relied upon a figure of 2,000. Consequently, there is a large rounding differential by using a weighted average emission rate to re-dispatch NGCC plants in building block 2. By applying a 70 percent capacity factor to each NGCC unit individually (as opposed to all generation units at once), there is a difference of over 5 millions tons of CO_2 emissions. The mass-based calculation also omits EE within the spreadsheet. As a result of this omission, the formula US EPA relies upon adds and subtracts the same value for EE in the same equation, i.e. *Ohio Final Mass Equivalent Generation Level= Historical Effected Fossil Generation + Incremental RE – Under Construction Nuclear – Incremental EE + Incremental EE.*

In addition to the mass-based calculation errors and general mathematical flaws, faulty assumptions for each building block are discussed below. Assuming *arguendo* that

[20] "Ohio EPA Comments on US EPA's June 18, 2014 Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule," Ohio Environmental Protection Agency, [79 FR 34830], 2014, 132.

the CPP survives legal scrutiny, the following should be considered by US EPA upon the construction of a final rule.

D. Building Block 1

1. Building block 1 is not technically feasible.

Ohio EPA, in its comments, highlights concerns regarding the heat rate improvement assumptions that are relied upon in the CPP. The PUCO shares these concerns and urges US EPA to account for the flawed assumptions contained within building block 1. Accordingly, the PUCO adopts and incorporates these comments by reference.[21]

2. The NERC reliability study highlights other faults with US EPA's regression analysis.

NERC also cites numerous problems with US EPA's regression analysis in building block 1. The NERC Reliability Study states that US EPA fails to account for (1) coal-fired plant retrofits; (2) subcritical vs. supercritical boiler designs; (3) fluidized bed combustion, integrated gasification combined-cycle (IGCC), and pulverized coal; (4) unit size and age; and (5) coal quality variations in moisture and ash.[22]

E. Building Block 2

1. The CPP's re-dispatch analysis ignores established dispatch control systems.

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21 *Id*.

22 "Potential Reliability Impacts of EPA's Clean Power Plan," North American Electric Reliability Corporation, Nov. 2014, 8. See Appendix B:17.

Ohio's status as a state that has separated and deregulated generation from distribution merits further discussion, as the construction of building block 2 is clearly devoid of this reality.

Ohio relies upon PJM to operate the bulk electric system and dispatch generation on a least-cost economic basis. Due to its status as a restructured state, Ohio depends on PJM and does not use an IRP process to determine what classification of generation units must be used, or when generating units can and cannot run. Rather, market forces provide the necessary incentives for generating resources to be built within the state, as well as to determine when existing units will run. Ohio's generating units may be owned by affiliates of regulated distribution utilities or may operate as independent merchant generators. The CPP's building block 2 fails to account for the generation dispatch structure that exists in a deregulated state.

In order to allow for Ohio to dispatch natural gas generating units at a 70 percent efficiency rate, dramatic industry overhauls would be needed. When determining which generators are required to ensure reliability, PJM considers cost and unit efficiency on a locational basis through SCED. Contrary to PJM's economic dispatch principles, the CPP suggests that PJM would need to perform environmental dispatch in lieu of economic dispatch. Rather than use pure economic efficiency to dispatch generation, PJM would be forced to take into account generation unit characteristics and essentially pick which units run more frequently, regardless of cost considerations. As previously discussed, this places PJM in an enforcement role for the 13 states and the District of

Columbia within PJM's footprint. Logistically, PJM may be faced with numerous dispatch plans that it must consider while also ensuring system reliability.

The CPP's environmental dispatch obligation cannot coexist within the SCED model. Advocates of the current construction of building block 2 have argued that RTOs could maintain the SCED model by artificially adding costs to carbon-emitting EGUs to ensure that these units dispatch less frequently, or not at all, while at the same time preserving the economic market maintained by PJM. This contemplated construct completely ignores the fundamental principles upon which SCED was developed. If building block 2 is implemented as proposed within the CPP, costs for these units would be artificial in nature. Unit efficiency would be ignored as no consideration would be given to the technical difficulties associated with ramping-up and ramping-down units. The SCED model would be decimated.

The PUCO opposes any such artificial adders or penalties to the SCED economic marketplace, as the goal of this economic marketplace is to ensure the delivery of reliable electricity to its consumers at affordable rates. It can be stated with absolute certainty that a carbon penalty would drastically increase the cost of electricity to Ohio consumers, as described in the next section. Furthermore, if coal units are not being utilized efficiently and are not being dispatched to allow for cost recovery, these plants may close, creating reliability concerns for all Ohio consumers.

2. Cost Impacts of Building Block 2

a. Quantifiable costs: changing economic dispatch to environmental dispatch would raise wholesale market prices by 39 percent and would cost Ohioans $2.5 billion more per year in electric costs in 2025.

To quantify the costs associated with implementing environmentally constrained dispatch for electricity in the PJM footprint, the PUCO utilized Ventyx's PROMOD IV cost modeling software. This software is a widely recognized, industry standard nodal production cost model that simulates the commitment and dispatch process of wholesale electricity markets under various scenarios. PROMOD IV is commonly used by RTOs and market participants for purposes such as transmission expansion planning and cost-benefit analysis. The PUCO maintains that the PROMOD IV modeling software is the proper tool to produce unbiased analysis relating to wholesale electricity markets and has leveraged this capability to support testimony in a number of proceedings before the PUCO.[23]

The PUCO's modeling methodology is superior to US EPA's Integrated Planning Model (IPM) for a number of reasons. Specifically, PROMOD IV accounts for losses and congestion that occur in the grid and the constraints that these impose on the reliable operation of electricity markets. Any model that does not fully and accurately account for these factors on both a regional and sub-regional level, including US EPA's IPM

[23] See Public Utilities Commission of Ohio Proceedings In the Matter of the Application of The Dayton Power and Light Company to Establish a Standard Service Offer in the Form of an Electric Security Plan, et al. Case Nos. 12-426-EL-SSO; and In the Matter of the Application of Ohio Power Company For Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143, in the Form of an Electric Security Plan, et al., Case Nos. 13-2385-EL-SSO.

model, would underestimate the impact of the proposed rule. Additionally, PROMOD IV not only allows for analysis to be conducted under current conditions, but also allows for forward-looking transmission cases to be incorporated into the dispatch algorithm. This facilitates long-term as well as short-term analysis, both of which are required due to the nature of US EPA's proposed rule.

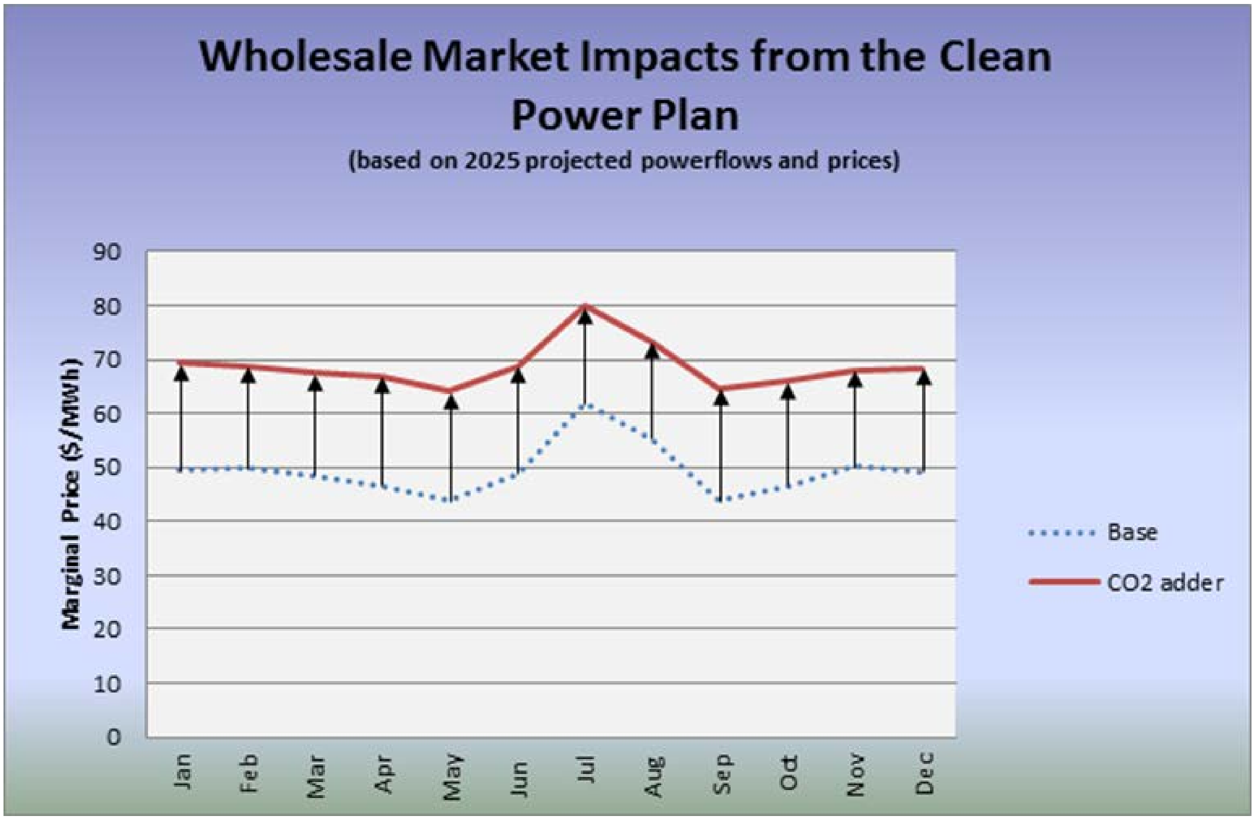
To the extent possible, the PUCO's modeling runs leveraged independent third-party data and transmission topography. Future transmission cases were developed to be consistent with transmission expansion planning expectations at the RTO level and were informed by PJM's Regional Transmission Expansion Planning and market efficiency studies.[24] All fuel price inputs represent nominal (non-inflation adjusted) values.

To analyze the impact of building block 2, the PUCO used PJM's 2025 market efficiency case as the base case. Using PJM's study, the PUCO placed a dispatch penalty on CO_2 emissions until the 70 percent utilization threshold was achieved for all existing and new NGCC units in Ohio. Additionally, the PUCO increased the price of natural gas in the building block 2 analysis to match US EPA's assumption that the proposed rule would increase natural gas prices by 10 percent.

The PUCO's modeling demonstrates that the switch from economic dispatch to environmental dispatch, as a result of building block 2, would cause wholesale market energy prices to be 39 percent higher in calendar year 2025 than prices would otherwise be without building block 2. The economic dispatch modeling is illustrated in the figure

[24] The PJM 2025 Market Efficiency Case was used in this analysis.

below. Compliance with building block 2 would cost Ohioans approximately $2.5 billion (in nominal dollars) more for electricity in 2025 alone.[25] The aggregate total price increase as a result of the CPP would be substantial.[26]



A 39 percent increase in energy prices is significant. Looking at the bigger picture, when considering economic impacts beyond just the price of electricity, the CPP would impose more strain on Ohioans as the cost of goods and services would increase as

25 See Appendix A.

26 As demonstrated in Appendix A, PUCO Staff used 2025 as the model compliance year. Between 2020-2024, actual costs will likely be less than $2.5 billion per year in nominal dollars, while the years between 2026-2029 will likely have higher costs than $2.5 billion per year in nominal dollars. However, it is worth noting that this estimate is conservative. It does not contemplate new generation beyond PJM's generation queue, nor does it include any likely transmission or infrastructure upgrades that would occur as a result of generation redispatch.

businesses are forced to pass on higher electricity costs. Given the combination of higher direct electricity costs and the fact that these costs would flow to every part of Ohio's economy, Ohioans would undoubtedly face financial hardship as a result of the CPP's sweeping reforms if the rule is finalized in its proposed form.

b. Presently unquantifiable but additional costs: the CPP would create presently unquantifiable, but major cost impacts due to increased capacity pricing and likely transmission upgrades.

By recommending a 70 percent utilization of natural gas-fired combined cycle units, the CPP would place additional financial pressure on the remaining existing fleet of coal-fired generation. Put simply, coal plants must run less in order for natural gas plants to run more. In running less, existing coal units would incur more start and slow down cycles. These units were never intended to be operated in this manner and cannot physically or economically operate as an efficient load-following resource.

This technical concern, coupled with the economic reality of coal-fired generators receiving less revenue due to less frequent dispatch, places tremendous pressure on existing coal-fired EGUs. This additional pressure would make many of the coal-fired generators that survived MATS vulnerable to retirement. If enough vulnerable generation opts for retirement, reliability of the grid would very quickly become threatened and costs would most certainly increase for consumers.

Any retirement of low-cost resources in the PJM capacity market would result in higher cost units clearing the market. Ohio recently experienced capacity prices as high as $357 per MW-day in the Cleveland area where prices were $125 per MW-day the preceding year, largely because of generation retirements. This increase in capacity pricing would of course be passed through to consumers and result in another major rate increase. The increased cost to consumers resulting from higher capacity clearing prices would be in addition to the increased costs discussed in the preceding section. The increased costs discussed in the previous section are related to the dispatch of electricity, or energy markets, whereas this section addresses capacity markets and associated pricing. All of these costs would be passed through to consumers.

In cases where sufficient capacity does exist but not in the correct location, retirements have resulted in expansive transmission projects. These projects, many occurring as a result of MATS, have cost Ohioans approximately $650 million dollars.[27] It stands to reason that as a result of the CPP, similarly expansive transmission projects would be launched due to coal plant vulnerabilities. This, again, is another cost impact of the CPP that Ohio consumers would be forced to bear.

The combined impact of increased energy market pricing, increased capacity market pricing and transmission upgrades would likely result in Ohio consumers paying exorbitantly higher electricity bills as a result of the CPP's lack of analysis of regional electric markets.

These increased costs would impact each of Ohio's residential, commercial and industrial/manufacturing customers. Residential consumers would have a harder time paying their bills and less money to support other aspects of Ohio's economy. Businesses would have higher production costs and less money available to employ Ohioans. Ohio's industrial/manufacturing industries would have far greater production costs, impacting not only their Ohio employee base, but also increasing the cost of their

[27] "Ohio EPA Comments on US EPA's June 2, 2014 Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule," Ohio Environmental Protection Agency, [79 FR 34830], 2014, 9. See Appendix B:5.

products which has far-reaching economic ramifications for those businesses and the state as a whole.

3. Reliability Impacts of Building Block 2

a. NERC has identified key reliability impacts created by building block 2.

The NERC Reliability Study highlights the reliability impacts of coal-fired generation units that may be forced into retirement as a result of building block 2. Specifically, the NERC Reliability Study explains that NGCC units typically follow the load of energy throughout the day. NGCC units are best suited to follow load as opposed to being relied upon for base load capacity like coal-fired units.[28]

The NERC Reliability Study touts the importance of diversification of fuel sources to offset unforeseen events such as abnormal weather, regional transfers and unplanned outages. Fuel diversification is also necessary to ensure reliability and minimize cost impacts.[29] Building block 2 challenges the principles of fuel diversity as a result of its increased reliance on natural gas.

The NERC Reliability Study provides that "[w]ith greater reliance on natural-gas-fired generation, the resiliency and fuel diversification that is currently built into the

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[28] "Potential Reliability Impacts of EPA's Clean Power Plan," North American Electric Reliability Corporation, Nov. 2014, 9. See Appendix B:17.

[29] *Id*.

system may be degraded, which NERC has highlighted in recent gas-electric interdependency assessments."[30]

NERC utilizes this past winter's polar vortex as a prime example of how fuel diversity is necessary to ensure grid reliability. In September 2014, NERC produced a study reviewing the events of the polar vortex. In that study NERC reported that 55 per-cent of total outages experienced during the polar vortex are attributable to natural gas-fired generators.[31] NERC went on to state that:

> Increased reliance on natural gas during the polar vortex exposed the industry to various challenges with fuel supply and delivery. This increased reliance, compounded by generation outages during the extreme conditions, increased the risks to the reliable operation of the BPS.
>
> As the industry relies more on natural-gas-fired capacity to meet electricity needs, it is important to examine potential risks associated with increased dependence on a single fuel type. The extent of these concerns varies from Region to Region; however, they are most acute in areas where power generators rely on interruptible natural gas pipeline transportation.
>
> Unlike coal and fuel oil, natural gas is not typically stored on site. As a result, real-time delivery of natural gas through a network of pipelines and bulk gas storage is critical to support electric generators. Natural gas is widely used outside the power sector, and the demand from other sectors—particularly coincident end-user gas peak demand during cold winter weather—critically affects gas providers' ability to deliver interruptible transportation service in the power sector. Additionally, demand for natural gas is expected to grow in other sectors (e.g., transportation, exports, and manufacturing).

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30 *Id*.

31 "Polar Vortex Review," North American Electric Reliability Council, Sep. 2014, 13. See Appendix B:19.

The PUCO will further examine the issues associated with gas/electric coordination below. It can be said with certainty that, purely from a reliability perspective, the NERC Reliability Study highlights that an even greater reliance on natural gas-fired generation, as contemplated in the CPP, would place reliability of the electric grid in jeopardy.

b. The CPP ignores the economic realities of fuel procurement for natural gas electric generation as well as the physical difficulty of fuel delivery to natural gas generators.

While Ohio is fortunate to be geographically situated in an area with extensive natural gas growth and development, the increased reliance on natural gas that is associated with a 70 percent NGCC generation utilization rate in the CPP ignores the economic realities of procuring natural gas, as well as the physical challenges of fuel delivery to NGCC units.

i. Firm fuel arrangements and spot market natural gas procurement can be volatile and costly.

The CPP is devoid of any analysis discussing the economic reality of procuring natural gas for NGCC units. If NGCC generators are to achieve a 70 percent utilization rate, these generators must consider purchasing firm fuel from a supplier via a firm-fuel contract. These firm fuel arrangements are not presently the industry standard due to their exorbitant costs and practical difficulties. Natural gas suppliers are generally betrothed first to natural gas distribution utilities and their consumers regarding the delivery of fuel. Electric generators take a subordinate role to gas utilities even if the generator has a firm fuel contract.

NGCC units that do not have firm fuel arrangements rely on the spot market to acquire fuel. This spot market can be volatile, especially during periods of high demand.[32] This scenario presented itself during the polar vortex this past winter. Natural gas units that did not go offline during the polar vortex were required to purchase fuel at high spot prices during the month of January, resulting in a record setting amount of uplift payments in excess of $650 million in the PJM footprint.[33]

The polar vortex highlights the difficult economic reality NGCC units face when purchasing fuel. This economic reality, of course, is passed through to consumers, creating yet another unquantifiable, but potentially massive rate increase as a result of the CPP and impacting reliability as stated by NERC.

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[32] Just this past winter alone, the Henry Hub Natural Gas Spot Price almost doubled from its 2013 levels of $4 to almost $8 in January 2014. ("*Henry Hub Natural Gas Spot Price*," United States Energy Information Administration, accessed: Oct. 22, 2014: http://www.eia.gov/dnav/ng/hist/rngwhhdd.htm). See Appendix B:6.

[33] In order to ensure that generation units or demand resources do not operate at a loss when following dispatch instructions from PJM, uplift credits are provided to resources that meet their obligations.

ii. Increased natural gas consumption requires physical infrastructure changes that are both capital and time intensive.

As new generation units come online and existing units are called-upon less frequently, constraints would arise that inhibit the physical delivery of fuel to an NGCC unit. Intensive analysis would need to be performed on a regional basis to determine how much gas would need to be drawn from the system and what proper pressure methodologies would need to be employed in order to identify capacity constraints, particularly in specific bottlenecks.

Further, as NERC points out, investment in natural gas-fired generation takes anywhere from "three to five years to plan, permit, sign contract capacity, finance, and build additional pipeline capacity, in addition to placing replacement capacity (*e.g.*, NGCC/CT units) in service. In light of the expeditious time frame set forth in the CPP, there may not be sufficient time for the necessary pipeline infrastructure or related resource capacity to be ready by 2020."[34] Additional infrastructure would be necessary not only to accommodate new natural gas generation, but to offset coal plant retirements.

The costs associated with this arbitrary 70 percent utilization rate would not only affect the electric consumer, but would increase costs to the natural gas utility consumer. Natural gas consumers may also be exposed to pass-through costs associated with the siting of new pipelines.

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[34] "Potential Reliability Impacts of EPA's Clean Power Plan," North American Electric Reliability Corporation, Nov. 2014, 10. See Appendix B:17.

4. Other Faulty Assumptions in Building Block 2

a. The CPP's volatility snapshot is not appropriate.

The CPP seems to conflate the concepts of volatility and affordability in its attempt to depict expected price increases as within acceptable, normal limits. Historically, electricity prices do exhibit a high degree of volatility, largely due to the volatile nature of fuel costs. However, this volatility manifests itself in both the upward and downward direction. In 2008, energy price volatility resulted in significant decreases in end-user consumer costs. In fact, it is quite easy to imagine a scenario in which energy prices may be significantly volatile from year to year with no appreciable net trend either upwards or downwards in consumer costs. Conflating the concept of volatility with affordability is an insufficient justification of whether the economic implications of the proposed rule are indeed tolerable.

b. The CPP's 70 percent capacity factor inappropriately utilizes nameplate capacity instead of seasonal capability.

The CPP relies on nameplate capability in calculating its 70 percent capacity factor for NGCC units. By utilizing nameplate capability, the CPP ignores the most precise information available that provides a true reflection of a generation unit's capability. Electric utility forecast reports that are filed before the PUCO require the use of net seasonal capability figures instead of nameplate capacity, as net seasonal capability accurately captures the demonstrated ability of generation equipment.[35] Seasonal capability considerations, as opposed to nameplate capacity, are also consistent with regional reliability standards.

Nameplate capacity reflects a nominal value that represents the size of the generator. However, this information does not actually indicate a generation unit's capability. It does not account for the generation unit's physical make-up, including the balance of plant equipment and systems as well as auxiliary loads. Nameplate capacity also does not take into consideration unit specific conditions like ambient temperature, humidity and elevation. Using seasonal capability, as opposed to nameplate capacity, better reflects the net capability of an NGCC unit.

5. Building block 1 and building block 2 are contradictory in implementation.

If heat rates are improved as contemplated by building block 1, coal-fired units would become more economic on a variable basis. Coal units, via the typical SCED model, would then be dispatched more and would displace NGCC units in dispatch. This is contra to the intent behind building block 2, which mandates that NGCC units be called upon at higher rates, and coal-fired units at lower rates. Further, the owner of a coal-fired EGU would be hesitant to invest in heat rate improvements if the unit would be

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[35] Ohio Adm. Code 4901:5-5-01(D). See Appendix B:7.

dispatched less. This demonstrates the contradictory nature of concurrently implementing building block 1 and building block 2.

NERC also highlights the lack of symmetry between building block 1 and building block 2. According to the NERC Reliability Study, as a result of building block 2, coal units would cycle more often; therefore, heat rate improvements across the entire coal fleet would be unlikely. Simply put, if coal units are dispatched less they would have to cycle on and off more often, thereby increasing the heat rate. This lack of symmetry would prove challenging to any state like Ohio that has a substantial coal fleet and is attempting to meet the requirements of building block 1.[36]

F. Building Block 3

1. The CPP's attempt to apply a blanket, national approach to renewable energy (RE) ignores the intricacies of Ohio's laws and policy.

Assuming the CPP survives likely legal challenges, the proposed RE targets fail to utilize state-specific approaches in determining their respective building block requirements. Individual state renewable portfolio standards (RPS) and energy efficiency programs reflect state-specific energy policy objectives, existing generation portfolios, varying degrees of electric market restructuring, participation in RTOs and other diverse characteristics embodied in state legislation and policy. The CPP, while preaching flexibility, does not fully take these individual state approaches into account in developing building

[36] "Potential Reliability Impacts of EPA's Clean Power Plan," North American Electric Reliability Corporation, Nov. 2014, 8. See Appendix B:17.

block 3. Assuming *arguendo*, that building block 3 is permissible, the following issues exist.

a. The CPP's Ohio RE targets are inconsistent with state law in Ohio.

The RE targets utilized in the CPP do not reflect current law in Ohio. US EPA should utilize 6.5 percent as the 2020 effective RE level for Ohio in deriving Ohio's RE targets, rather than the number included in the original calculation.[37] Furthermore, as state legislatures control the adoption and amendment of RPS policies, US EPA must account for this by allowing states to amend their implementation plans and adjust goal emission rates accordingly, assuming RPS mandates are included in state plans.

b. The CPP's NERC-based regions reflect a bias against states with RPS standards.

The CPP creates a RE generation target for Ohio based upon the average of all 2020 RPS requirements in the NERC-based East Central region. States without RPS mandates in this region, however, are excluded from this calculation.[38] This exclusion manufactures more aggressive RE targets for the RPS states within the region, ignoring

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[37] Ohio Substitute Senate Bill Number 310, 130th General Assembly, Regular Session, 2014. See Appendix B:8.

[38] Virginia and West Virginia do not have RPS mandates, but rather have voluntary targets. (Virginia: Incentives/Policies for Renewables & Efficiency, DSIRE, accessed: Nov 26, 2014, http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=VA10R&re=1&ee=1; West Virginia: Incentives/Policies for Renewables & Efficiency, DSIRE, accessed: Nov 26, 2014, http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=WV05R&re=1&ee=1). See Appendix B:9.

the reality across the country that renewables have not yet penetrated all state market-places. The CPP can correct this by utilizing state-specific RPS requirements (or lack thereof) in considering RE benchmarks, as opposed to using this regional approach.

c. The CPP wrongfully excludes hydropower generation in determining the annual growth formula for Ohio.

The CPP incorrectly excludes hydropower generation from the calculations used to determine Ohio's growth factor rate (as discussed in a subsequent section). Although the CPP correctly notes that hydropower generating capacity has been relatively flat over the last 20 years, this broad generalization does not take into account Ohio's distinctive characteristics.

It is true that only a handful of states have large, existing hydroelectric facilities. However, over the past 15 years, significant hydropower projects have been developed and are continuing to be developed along the Ohio River within the PJM footprint in the East Central region.[39]

The CPP should recognize these investments in hydropower capacity in Ohio and the region. The CPP should include Ohio's 2012 hydropower generation in the 2012 historical baseline RE data and utilize hydropower generation in determining the annual growth factor used for calculating Ohio's RE generation targets.

[39] "Hydroelectric Power," American Municipal Power, Inc., accessed: Nov. 10, 2014, http://www.amppartners.org/generation/hydro. See Appendix B:10.

d. Ohio's growth factor rate is incorrect.

While the PUCO notes its continuous objection to the legality of the CPP, assuming *arguendo* that the CPP survives legal challenge, the proposed RE targets in the CPP should be modified to reflect a state-specific approach that is consistent with state law and adjusts for the numerical flaws discussed above.

e. The CPP does not account for deviations from historical norms.

The CPP uses an unrealistic assumption in its calculations by failing to account for the expansion of RPS requirements that are not within historical norms of deployment. Additionally, the CPP could create an unintended consequence of driving-up costs for RE resources. As detailed below, the CPP assumes that costs associated with implementing the BSER would be "reasonable" by analyzing historical RPS compliance costs.

> RE generation at the levels represented in the best practices scenario can be achieved at reasonable costs. This finding has been confirmed with more recent RPS cost data, including a report that determined 2010-2012 retail electricity price impacts due to state RPS policies to be less than two percent, with only two states experiencing price impacts greater than three percent.[40]

However, the CPP evaluation does not take into consideration the cost suppression effect of the federal Production Tax Credit and the Investment Tax Credit, which expire at the end of 2013 and 2014, respectively. Additionally, as RPS requirements continue to

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[40] "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," United States Environmental Protection Agency, 79 Fed. Reg. 34,830, 34,869, Jun. 2, 2014 (to be codified at 40 C.F.R. pt. 60). See Appendix B:11.

grow over time, it is possible that RE may be difficult or infeasible to procure due to the technical or economic availability of RE resources. Most states address these potential constraints through RPS policies containing *force majeure* and annual compliance payment provisions that address resource availability, as well as cost cap provisions that address unusual pressure for cost increases to ratepayers.

f. The CPP does not include Ohio's *force majeure* or cost-cap provisions in calculating the RE target.

Ohio includes *force majeure* and cost-cap provisions in its alternative energy rules that are codified in the state statute. An electric utility or electric service company may modify its RPS compliance obligation, if the PUCO determines that *force majeure* conditions exist, based on the demonstration of the electric utility or electric service company.

> 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.[41]

An electric utility or electric services company may not be required to fully comply with a specific RPS benchmark if the PUCO determines that the cost cap provisions have been met based on proof provided by the electric utility or electric service company:

> 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

[41] Ohio Adm. Code 4901:1-40-06(A)(1). See Appendix B:12.

> 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.[42]
>
> 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.[43]

The CPP ignores future cost considerations when creating the RE target for Ohio. Should the CPP be deemed legally permissible, US EPA should modify it in accordance with the state-specific considerations outlined above.

2. The CPP should not utilize a floor-based approach for setting RE targets.

The CPP's floor-based approach for setting Ohio's RE targets is faulty. The CPP uses US EIA's 2012 net generation from RE sources (wind, hydroelectric conventional, other biomass, wood and wood derived fuels, and solar thermal and photovoltaic) for the total electric power industry in Ohio. If Ohio's goal is modified to include specific floor-based requirements it would limit the ability of the state to create a plan for compliance with the state goals, and would operate *contra* to the flexibility principles preached by US EPA in developing this plan.

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[42] Ohio Adm. Code 4901:1-40-07(B). See Appendix B:13.

[43] Ohio Adm. Code 4901:1-40-07(E). See Appendix B:14.

3. The CPP does not provide guidance that would allow states to receive credit for out of state RE and EE measures.

Assuming *arguendo* that the CPP is deemed legally permissible, Ohio should be allowed to take credit for RE and EE measures that occur out of state but are funded, at least in part, by Ohio. States are able to demonstrate that reductions would not be double-counted by using currently structured RECs for interstate trading of renewable energy attributes.[44] In addition, RECs can be issued, tracked and retired through attribute tracking systems. The attribute tracking systems provide a reliable means to demonstrate that RE attributes are not being double-counted. This is especially critical for states like Ohio in which RPS policies have been designed to include out-of-state resources. The PUCO is troubled by the implementation changes that would have to occur as necessitated by the CPP.

4. The NERC reliability study outlines important reliability challenges associated with building block 3.

The NERC Reliability Study sets forth the following concerns with Building Block 3, all of which could impact the reliability of the electric grid:[45]

- The CPP analysis relies on resource projections that may overestimate reasonably achievable expansion levels and

[44] Double-counting is prohibited in Ohio consistent with Ohio Administrative Code 4901:1-40-04(D)(4). See Appendix B:15.

[45] "Potential Reliability Impacts of EPA's Clean Power Plan," North American Electric Reliability Corporation, Nov. 2014, 13. See Appendix B:17.

exceed NERC and industry plans and do not fully reflect the reliability consequences of renewable resources.

- Increased reliance on variable or renewable energy resources (VER) can significantly impact reliability operations and require more transmission and adequate essential reliability services (ERS) to maintain reliability.

- With a greater reliance on VERs, transmission and related infrastructure expansion, lead times may not align with the CPP implementation timeline.

The CPP lacks meaningful discussion on how to mitigate any detrimental impacts that may arise as a result of an increased reliance on VERs.

G. Building Block 4

The CPP establishes Ohio's EE targets based on presumptions from outdated figures. As a result, the CPP penalizes states that were early adopters of EE goals and mandates. The CPP also fails to take Ohio's state law into account when devising Ohio's EE targets in building block 4. Further, the CPP fails to consider costs associated with EE achievements made prior to 2012.

1. The CPP punishes states that began implementing EE requirements prior to 2012.

The CPP's EE target for Ohio is inconsistent with Ohio's state law and actually punishes Ohio as an early adopter of EE standards. The CPP provides more favorable targets to states that have not yet implemented EE programs, as well as states that have programs in their infancy. Further, these states are given substantially more leeway through a more gradual glide path to meet the CPP's mandates. Consequently, it appears that Ohio has been punished for its early action rather than receiving credit for it; as a result, the CPP's EE targets for Ohio are grossly overestimated.

2. The CPP's Ohio EE targets are inconsistent with state law in Ohio.

a. Ohio's larger electric consumers can soon opt out of state EE programs.

The CPP's assumptions do not reflect the fact that, in Ohio, larger electric customers will soon be able to opt out of state-mandated electric utility EE programs.[46] Ohio is uniquely situated in that larger electric customers will maintain the flexibility and discretion to determine whether continued participation in EE programs is in their best interests based on their individual circumstances. Due to these Ohio opt-out provisions, participation rates will likely change over time, making the number of participants impossible to predict. The CPP's EE targets for Ohio are based on electricity consumption levels that include customers who may become non-participants under Ohio's EE programs. The CPP's overestimation of Ohio's EE targets, would both increase costs and shift those higher costs associated with EE to the remaining ratepayers, and is contra to Ohio law.

b. The CPP's EE targets for Ohio do not use a gross savings reporting mechanism.

[46] See Appendix B:8.

Ohio cannot easily quantify annual incremental electricity savings in the manner that the CPP proposes. The PUCO depends upon evaluation, measurement and verification (EM&V) reports that are created by an independent third party to determine EE savings. Assuming *arguendo* that building block 4 is permissible, the CPP should consider using a gross savings reporting mechanism to allow for maximum consideration of energy savings that may not be reflected by just considering EE on a net savings basis. Currently, the PUCO considers EE on a gross savings basis. Revising the PUCO's tracking methodologies to a net savings basis would be costly, difficult to implement and contrary to Ohio statute.

3. The CPP's one-size-fits-all model ignores states processes.

On a broader basis, these distinctions between the CPP and Ohio programs highlight the importance of avoiding any disruption that could nullify Ohio's well-established state processes. The CPP's attempt to harmonize state approaches into a one-size-fits-all model ignores Ohio's unique approach towards RE and EE for electric utilities. Ohio has state-specific restrictions on what types of facilities are classified as renewable energy that may differ from other state or federal classifications. The CPP adopts a one-size-fits-all policy that does not give Ohio discretion to define RE resources consistent with its own statutes and policies.

Similarly, Ohio's EE standards are defined differently than EE standards in other states. The CPP should provide deference to the Ohio General Assembly's jurisdiction over state policy and safeguard such flexibility to avoid a scenario where a federal entity is forcing a state to violate its own laws. Because every state's RE and EE requirements are different, a wide range of options for EM&V protocols is critical so that states can develop plans tailored to individual state needs and conditions.

4. The NERC reliability study outlines important reliability challenges associated with building block 4.

The NERC Reliability Study sets forth the following concerns with building block 4, all of which could impact reliability of the electric grid.[47]

- US EPA appears to overestimate the amount of energy efficiency expected to reduce electricity demand over the compliance time frame. The results of overestimation have implications to electric transmission and generation infrastructure needs.

- Substantial increases in energy efficiency programs exceed recent trends and projections. Several sources, including but not limited to NERC, US EIA, EPRI, and various utilities, have published reports, analysis, and forecasts for energy efficiency that do not align with the CPP's assumed declining demand trend.

- The CPP assumption appears to underestimate costs and may underestimate the capital investments that would be required by utilities to sustain energy efficiency performance through 2030.

- The offsetting requirements in more coal retirements, along with expansions in natural gas and VERs, in a constrained time period could potentially result in reliability or ERS constraints.

[47] "Potential Reliability Impacts of EPA's Clean Power Plan," North American Electric Reliability Corporation, Nov. 2014, 16. See Appendix B:17.

The CPP lacks an appropriate analysis of the serious reliability impacts building block 4 would place on the nation's electric grid.

H. The CPP's nuclear capacity considerations reflect a bias towards new nuclear generation facilities.

The PUCO opposes the CPP's approach toward nuclear energy. As proposed, the CPP's nuclear capacity considerations reflect an inherent bias towards building new nuclear capacity. The CPP acknowledges that new nuclear capacity is extremely costly, which translates into a bias towards traditional, vertically-integrated states that utilize rate of return regulation. All five nuclear EGU's that are currently under construction are in traditionally regulated states.[48] Consequently, the superficial nuclear considerations penalize deregulated states such as Ohio which depend on market conditions to develop new generating units.

Not only do the CPP's nuclear capacity considerations disadvantage deregulated states, the CPP again overgeneralizes by using a national six percent proxy for the amount of nuclear capacity at risk of retirement. While the six percent figure is derived from the US EIA Annual Energy Outlook, it fails to reflect the fact that Ohio's nuclear generation fleet accounts for almost 12 percent of the state's electricity generation portfolio.[49]

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[48] The units currently under construction include: Watts Bar 2 in Tennessee; Vogtle 3-4 in Georgia; and Summer 2-3 in South Carolina. (See *U.S. Nuclear Power Plants*, NUCLEAR ENERGY INST., accessed: Nov. 12, 2014, http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants). See Appendix B:16.

[49] "Where does Ohio's electricity come from?" Public Utilities Commission of Ohio; See Appendix B:22.

III. Support for the Pennsylvania Public Utility Commission (PAPUC)

Pennsylvania is similarly situated to Ohio in the electricity marketplace. Pennsylvania is a deregulated state that relies on wholesale markets. It also serves a similarly large load that drives its economy. As such, both Ohio and Pennsylvania would experience similar negative impacts from the CPP. Accordingly, the PUCO specifically adopts the following positions as expressed in the comments from PAPUC:

- Coal-fired generation in PJM is currently under severe stress.[50]
- EPA's estimated 70% utilization rate for NGCC plants may not be achievable.[51]
- EPA's building block 2 proposal fails to account for the effects of extreme weather events on availability of NGCC resources as well as the lack of electric/gas supply coordination.[52]
- EPA's building block 2 proposal fails to consider the existing regulatory delays in approving interstate natural gas pipelines by the FERC.[53]

IV. Reliability Safety Valve

As previously discussed, if the CPP were to withstand legal challenges discussed in these comments and the comments of Ohio EPA and Ohio Attorney General, the

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[50] "PAPUC Comments on US EPA's June 18, 2014 Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule," at 29-30.

[51] *Id.* at 35-36.

[52] *Id.* at 36-39.

[53] *Id.* at 39-43.

PUCO supports the concept of a reliability safety valve as proposed by PJM and other RTOs. There must be a mechanism in place to assess or mitigate the stress the CPP would place on the electric grid. Absent a reliability safety valve, there is no means for RTOs to ensure availability of short-term capacity during times of peak usage. This safety valve, if evoked, should not act to the detriment of states and their CO_2 goal rates. If the safety valve is evoked to ensure reliability of the electric grid, state rates should be adjusted to account for the trigger of the safety valve.

V. Conclusion

The PUCO appreciates the opportunity to submit comments to US EPA regarding the proposed Clean Power Plan. The PUCO again asserts that the CPP is not legally enforceable as constructed. However, assuming *arguendo* that the CPP survives legal scrutiny, the PUCO respectfully requests that US EPA consider these comments when constructing the final CPP rule, and specifically, Ohio's goal emission rates.

The PUCO also implores US EPA to consider the overarching necessity of delivering reliable and affordable electric service to Ohio's consumers. This need is vital to the health and well-being of Ohio's consumers and economy.

Respectfully submitted,

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PUCO staff conducted an analysis regarding the utilization of building block 2 in US EPA's proposed CPP. The primary modeling tool used to complete this analysis was PROMOD IV, a dispatch simulation software licensed from Ventyx. The analysis considered a base case, which represented business as usual assuming no building block 2 compliance, and a change case, which represented a future where a forced 70 percent utilization of NGCC units fulfilled Ohio's proposed compliance obligations per building block 2. The analysis holds all other variables constant except the studied effect. Consequently, it was necessary to make many assumptions in order to conduct this analysis. The following is a list of key assumptions:

- PJM's 2025 market efficiency case was used in this analysis as the base case.

- Since an increased reliance on natural gas would generally exert an upward pressure on natural gas prices, staff adjusted the natural gas prices between the change case and the base case. Staff used US EPA's estimate of a 10 percent increase in natural gas prices in the change case while conducting the analysis.

- In order to cause existing and new NGCC units in Ohio to be dispatched at 70 percent of their potential, it was necessary to modify the cost at which resources with differing environmental characteristics are bid into the PJM market. To cause NGCC units to be dispatched in lieu of other resources, a carbon price adder of $27/ton[54] for all coal and oil fired units was derived. Because Ohio is part of a larger market, and the prevailing assumption is that other states would also comply with the CPP, the PUCO staff assumed that all coal and oil units in PJM were affected by the CO_2 cost adder.

- The CO_2 cost adder was assumed to be an actual cost that is incurred by generating units and reflected in their bids to supply energy. This cost would, therefore, be reflected in the locational marginal price that load serving entities pay for electricity.

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[54] The Midcontinent Independent System Operator's (MISO's) estimate of the cost to comply with building block 2 starting in 2020 is $53/ton. The MISO estimate is an overall cost that includes both energy and capacity costs. The estimate was included in a presentation titled "GHG Regulation Impact Analysis - Initial Study Results", given during the Planning Advisory Committee meeting on 9/17/2014.

- The PJM 2025 market efficiency case included Senate Bill 221 benchmarks prior to recent legislative changes. Such impacts were considered equally in both the base case and the change case.

- All units assumed to be in the PJM Interconnection queue in the 2025 market efficiency case were treated as new future units in both the base case and the change case.

- For purposes of the analysis, the effects of a mass-based standard were not studied.

- The AEP-Dayton Hub, was utilized as the pricing point for comparison of the future electricity prices under the base case and the change case.

- Despite the disagreement with US EPA in regard to the use of nameplate capacity in determining utilization potential, the analysis used nameplate capacity when calculating utilization to resemble US EPA's expectations as closely as possible.

- PROMOD outputs of locational marginal electricity prices and EDU load forecasts were used to predict the wholesale market impacts to Ohio. The calculations are included in the tables in this appendix.

2025 Load Forecasts of Ohio Electricity Distribution Utilities and 2025 AEP-Dayton Hub Electricity Price (in Nominal Dollars)

Month	Company 1 Generation (MWh)	Company 2 Generation (MWh)	Company 3 Generation (MWh)	Company 4 Generation (MWh)	Total Monthly EDU Load (MWh)	2025 Wholesale Electricity Price Difference at the AD Hub ($/MWh)	Total Cost of Electricity Uplift due to the Clean Power Plan
Jan	1,964,959.86	4,106,219.68	4,735,823.96	1,305,898.46	12,112,901.97	$19.98	$241,978,988.37
Feb	1,811,848.53	3,619,723.93	4,192,515.49	1,166,432.06	10,790,520.01	$18.88	$203,757,254.48
Mar	1,770,120.84	3,676,924.92	4,397,486.89	1,095,744.59	10,940,277.24	$18.84	$206,169,415.12
Apr	1,598,507.32	3,284,641.92	4,008,130.73	963,919.03	9,855,199.01	$20.39	$200,959,888,39
May	1,726,484.09	3,422,119.26	4,117,329.47	1,008,840.48	10,274,773.30	$20.02	$205,730,694.09
Jun	1,979,531.51	3,721,231.95	4,358,103.74	1,104,844.92	11,163,712.12	$19.81	$221,206,443.86
Jul	2,187,387.95	4,206,344.95	4,763,571.18	1,172,737.95	12,330,042.04	$18.10	$223,121,127.10
Aug	2,183,357.71	4,015,790.38	4,748,354.97	1,232,729.76	12,180,232.81	$17.90	$217,998,000.46
Sep	1,782,744.33	3,439,585.14	4,056,464.60	1,003,704.44	10,282,498.51	$20.98	$215,678,079.69
Oct	1,642,793.13	3,373,458.01	4,056,464.60	994,497.51	10,067,213.25	$19.35	$194,839,775.67
Nov	1,719,443.13	3,440,855.11	4,044,828.67	1,026,036.39	10,231,163.30	$17.79	$181,979,207.78
Dec	1,964,158.31	3,902,714.27	4,444,925.69	1,199,447.42	11,511,245.68	$19.22	$221,244,031.67
Total Annual Company Load	22,331,336.72	44,209,609.53	51,924,000.00	13,274,833.00	131,739,779.20	$19.27	$2,534,662,906.68

2025 NGCC Generation

Month	Ohio NGCC (MWh)
Jan	3,528,578.10
Feb	2,265,089.81
Mar	2,703,712.99
Apr	3,779,072.14
May	3,269,461.44
Jun	2,902,552.12
Jul	3,961,680.12
Aug	3,482,712.58
Sep	3,310,253.47
Oct	3,892,749.31
Nov	3,384,197.35
Dec	3,080,197.62
Total	39,560,257.81

2025 LMP comparison at the AD Hub

	Base Case ($/MWh)	Change Case ($/MWh)
Jan	49.34	69.32
Feb	49.83	68.72
Mar	48.58	67.42
Apr	46.61	67.01
May	44.04	64.07
Jun	48.95	68.77
Jul	61.90	80.00
Aug	55.33	73.23
Sep	43.78	64.76
Oct	46.62	65.97
Nov	50.20	67.99
Dec	49.24	68.46
	49.54	68.81
	% Increase	38.90%

Nameplate Capacity (MW)	Capacity Factor (%)	Average NGCC (MW)
6,368	70.92	4,516